Standard Review Projects and AB 1082/1083 Pilots

Evaluation Year 2025 (Year 5)

Third-Party Evaluation Report

September 2026













Prepared for
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San Diego Gas & Electric, and Liberty Utilities)
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Acronym List

Acronym	Definition
AB	Assembly Bill
ACF	Advanced Clean Fleets
ACS	American Community Survey
ACT	Advanced Clean Trucks
ADA	Americans with Disabilities Act
AFDC	Alternative Fuels Data Center
AL	Advice Letter
AMI	Advanced metering infrastructure
APL	Approved Product List
AR5	IPCC's published fifth assessment report
BABA	Build America, Buy America
BAU	Business-as-usual
BEV	Battery electric vehicle
BTM	Behind-the-meter
CaaS	Charging as a Service
CAISO	California Independent System Operator
CARB	California Air Resources Board
CBG	Census block group
CCFR	California Clean Fuel Reward
CCS	Combined Charging System
CEC	California Energy Commission
CFI	Charging and Fueling Infrastructure
CH_4	Methane
CNG	Compressed natural gas
CO	Carbon monoxide
COBRA	CO-Benefits Risk Assessment Health Impacts Screening and Mapping tool
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CVRP	Clean Vehicle Rebate Project
DAC	Disadvantaged Community
DC	Direct current
DCFC	Direct current fast charger
DGE	Diesel gallon equivalent
DMV	Department of Motor Vehicles
DOE	U.S. Department of Energy
DPR	Department of Parks and Recreation
DSA	Division of the State Architect
EMFAC	Emissions Factors
EPA	U.S. Environmental Protection Agency
EV	Electric vehicle
EV-HP	EV high-power
EVAS	EV Advisory Services
EVSE	Electric vehicle supply equipment
EVSP	Electric vehicle service provider
EY	Evaluation Year

Acronym	Definition
FCEV	Fuel cell electric vehicle
FHWA	Federal Highway Administration
GGE	Gasoline gallon equivalent
GHG	Greenhouse gas, here including CO_2, CH_4, and N_2O
GSE	Ground Support Equipment
GVWR	Gross vehicle weight rating
GWP	Global Warming Potential
HVIP	Hybrid and Zero Emission Truck and Bus Voucher Incentive Project
ICE	Internal combustion engine
ICT	Innovative Clean Transit
IOU	Investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IRA	Inflation Reduction Act
ISO	International Organization for Standardization
IV-2SLS	Instrumental variable two-stage least squares
kW	Kilowatt
kWh	Kilowatt-hour
L1	Level 1
L2	Level 2
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicle
LMI	Low- and moderate-income
MCS	Megawatt Charging System
MDHD	Medium- and heavy-duty
ME&O	Marketing, education, and outreach
MPA	Master participation agreement
MW	Megawatt
MWh	Megawatt-hour
MT	Metric ton
NEVI	National Electric Vehicle Infrastructure
N_2O	Nitrous oxide
NH_3	Ammonia
NO_X	Oxides of nitrogen
NPS	Net Promoter Score
NSP	Network service provider
NTG	Net-to-gross
OEM	Original equipment manufacturer
OIR	Order Instituting Rulemaking
OLS	Ordinary least squares
ORION	Off-Road Inventory Online
PAC	Program Advisory Committee
PAI	Program Attribution Index
PAO	Public Advocates Office
PG&E	Pacific Gas & Electric Company
PHEV	Plug-in hybrid electric vehicle
PM	Particulate matter
PTD	Program-to-Date

Acronym	Definition
PYDFF	Power Your Drive for Fleets
REDWDS	Responsive, Easy Charging Products with Dynamic Signals
ROG	Reactive organic gas
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SO_2	Sulfur dioxide
SO_x	Oxides of sulfur
SRP	Standard Review Projects
SUV	Sport utility vehicle
TCM	Truck Choice Model
TCO	Total cost of ownership
TEAS	Transportation Electrification Advisory Services
TEC	The Energy Coalition
TOU	Time-of-use
TRU	Transportation refrigeration unit
TTM	To-the-meter
VAP	Vehicle acquisition plan
V2G	Vehicle-to-grid
VGI	Vehicle-grid integration
VSL	Value of a statistical life
ZEV	Zero-emission vehicle

1. Executive Summary

This report summarizes findings and lessons learned from an independent evaluation of 12 active programs to build electric vehicle (EV) charging infrastructure for light-, medium-, and heavy-duty vehicles, administered by four California Utilities. These programs were authorized under California Public Utilities Commission (CPUC) decisions in 2018 and 2019[1] and support goals in Senate Bill (SB) 350 Clean Energy and Pollution Reduction Act of 2015 and Assembly Bills (AB) 1082 and 1083. This report builds on the Evaluation Year (EY) 2024 report[2] with new findings and lessons learned for EY2025.

Table 1 summarizes the 12 active transportation electrification programs and their authorized budgets.

Table 1. Summary of Utility Programs

Utility	Program	Description	Budget
Southern California Edison (SCE)	Charge Ready Transport	Public and private fleet medium- and heavy-duty (MDHD) make-ready and customer infrastructure.	$342.6M
	Schools Pilot	Direct installation of and incentives for make-ready infrastructure and chargers at K–12 schools, community colleges, and universities.	$9.9M
	Parks Pilot	Direct installation of and incentives for make-ready infrastructure and chargers at public parks and beaches.	$9.9M
Pacific Gas & Electric (PG&E)	EV Fleet	Public and private fleet MDHD make-ready and customer infrastructure.	$236.3M
	Schools Pilot	Direct installation of and incentives for make-ready infrastructure and chargers at K–12 schools, community colleges, and universities.	$5.8M
	Parks Pilot	Direct installation of and incentives for make-ready infrastructure and chargers at public parks and beaches.	$5.5M
	EV Fast Charge	Installation of Utility-owned direct current fast chargers (DCFCs).	$22.4M
San Diego Gas & Electric (SDG&E)	Power Your Drive for Fleets	Public and private fleet MDHD make-ready and customer infrastructure.	$107.4M
	Schools Pilot	Direct installation of and incentives for make-ready infrastructure and chargers at K–12 schools, community colleges, and universities.	$9.9M
	Parks Pilot	Direct installation of make-ready infrastructure and chargers at public parks and beaches.	$8.8M
Liberty Utilities	Schools Pilot	Direct installation of and incentives for make-ready infrastructure and chargers at K–12 schools, community colleges, and universities.	$3.9M
	Parks Pilot	Direct installation of and incentives for make-ready infrastructure and chargers at public parks and beaches.	$0.78M

[1] Decisions 18-05-040, 19-08-026, and 19-11-017.

[2] For EY2024 impacts, please see: Cadmus, Energetics, et al. (2025). *Standard Review Projects and AB 1082/1083 Pilots: Evaluation Year 2024 (Year 4) Third-Party Evaluation Report*. www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/sb-350-te/srp-ab10821083-2024-evaluation-report092025.pdf

1.1. Terminology

Throughout this report, the Evaluation Team uses several technical terms:

- **Site.** A single geographic location at which a Utility customer has installed charging ports as part of one of the 12 Utility programs.[3]
- **Charging Station.** A site with one or more EV charging ports.
- **EY2025 Sites.** Sites activated in calendar year 2025.
- **Program-to-Date (PTD) Sites.** Sites activated in the program from inception through the end of 2025.
- **2025 Actual.** Impacts in calendar year 2025 from PTD sites.
- **PTD Actual.** Impacts in all years from PTD sites.
- **10-Year Projection.** Projected impacts from PTD sites through 10 years of equipment life.
- Electric Vehicle Supply Equipment (EVSE). A charger with one or more ports.
- **Ports.** The connectors that can concurrently charge vehicles from a single EVSE.
- **Light-duty vehicles (LDVs).** Class 1 and Class 2a vehicles. Gross vehicle weight rating (GVWR) up to 8,500 lbs.
- **Medium-duty vehicles (MDVs).** Class 2b through Class 6 vehicles. GVWR between 8,501 lbs. and 26,000 lbs.
- **Heavy-duty vehicles (HDVs).** Class 7 and Class 8 vehicles. GVWR over 26,001 lbs.
- **Unexpected Charging.** Charging sessions that do not align with typical charging behavior at workplace sites (i.e., overnight and weekends).

This evaluation uses the following conventions to describe the status of sites as they advance toward activation and use:

- **Utility Construction Completed:** Sites where the Utility has completed its part of the installation. This could be to-the-meter (TTM), behind-the-meter (BTM), or a turnkey installation.
- **Activated:** Sites with charging stations installed and available for use.
- **Operational:** Sites for which advanced metering infrastructure (AMI) and/or electric vehicle service provider (EVSP) energy usage data have been received from the Utility or EVSP.
- **Closed Out:** Sites for which financial documentation has been finalized by the Utility and incentives for the installed chargers have been paid.[4]

[3] Utilities sometimes refer to a site as a "project."

[4] At some closed out sites, the Utilities still plan to pay incentives for future chargers.

Table 2 summarizes site counts denoted in this evaluation for EY2025 and the program to date. EY2025 sites, shown in white columns, include sites that reached a given site status (such as Activated) between January 1, 2025, and December 31, 2025. PTD sites, shown in green columns, include all sites since the launch of the program that reached a given site status as of December 31, 2025.

Table 2. Site Counts for EY2025 Sites and PTD Sites

Utility	Program	Utility Construction Completed		Activated		Operational		Closed Out	
		EY2025	PTD	EY2025	PTD	EY2025	PTD	EY2025	PTD
SCE	Charge Ready Transport	33	132	29	115	29	115	21	76
	Schools	5	30	8	30	9	30	2	21
	Parks	0	0	0	0	0	0	0	0
PG&E	EV Fleet	72	182	60	170	57	159	84	158
	Schools	3	15	3	15	3	15	3	15
	Parks	0	0	0	0	0	0	0	0
	EV Fast Charge	5	36	3	32	3	32	10	32
SDG&E	PYDFF	15	41	12	37	12	37	5	28
	Schools	7	26	7	26	7	25	5	22
	Parks	0	11	0	11	0	11	0	11
Liberty Utilities	Schools	0	1	0	1	0	1	0	1
	Parks	0	0	0	0	0	0	0	0
Total		140	474	122	437	120	425	130	364

Counts in Table 2 are not additive between the four site statuses (Utility Construction Completed, Activated, Operational, and Closed Out). In general, the site count in the Closed Out column is a subset of sites in the Operational column, which is a subset of sites in the Activated column, which is a subset of sites in the Utility Construction Completed column. Since program inception to the end of 2025, the MDHD programs have had the most sites reach Utility Construction Completed (355), followed by the Schools Pilots (72), PG&E EV Fast Charge (36), and the Parks Pilots (11).

1.2. Findings

This section summarizes program findings. For simplicity, programs are grouped into two program bundles based on similarities in program design:

- **MDHD Bundle:** PG&E EV Fleet, SCE Charge Ready Transport, and SDG&E PYDFF
- **Public Charging Bundle:** Liberty Schools and Parks, PG&E EV Fast Charge, PG&E Schools and Parks, SCE Schools and Parks, and SDG&E Schools and Parks

Table 3 summarizes the program impacts by bundle for EY2025.

Table 3. Program Impacts by Bundle

Impact Parameter	MDHD Bundle		Public Charging Bundle	
	EY2025	PTD	EY2025	PTD
Population of Activated Sites	101	322	21	115
Ports Installed in Analyzed Sites	1,905	5,489	167	835
EVs Supported [a]	2,790	8,715	N/A	N/A
Electric Energy Consumption (MWh)	22,396	176,254	348	14,253
Petroleum Displacement (diesel gallon equivalent [DGE])	1,848,923	14,871,619	21,896	1,090,721
Greenhouse Gas (GHG) Emission Reduction (metric tons [MT]) [b]	14,756	122,353	193	8,928
Oxides of Nitrogen (NO_X) Reduction (kg) [c]	4,896	96,526	N/A	N/A
Particulate Matter (PM_{10}) Reduction (kg)	94	1,402	1	45
Particulate Matter ($PM_{2.5}$) Reduction (kg)	88	1,306	1	41
Reactive Organic Gas (ROG) Reduction (kg)	965	12,124	11	811
Carbon Monoxide (CO) Reduction (kg)	85,550	722,384	467	24,771

[a] The Team derived the EVs supported value for MDHD programs from applicants' vehicle acquisition plan (VAP). This value represents the maximum number of vehicles expected to be supported by the charging infrastructure.
[b] GHGs include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) multiplied by their respective Global Warming Potential (GWP) as defined by the Intergovernmental Panel on Climate Change (IPCC) published fifth assessment (AR5). See *Appendix B* for details).
[c] The Team did not report NO_X for public charging, because unlike most MDHD market sectors for which the counterfactual is a diesel, the counterfactual for the LDV market sector is a gasoline internal combustion engine (ICE).

1.3. Lessons Learned

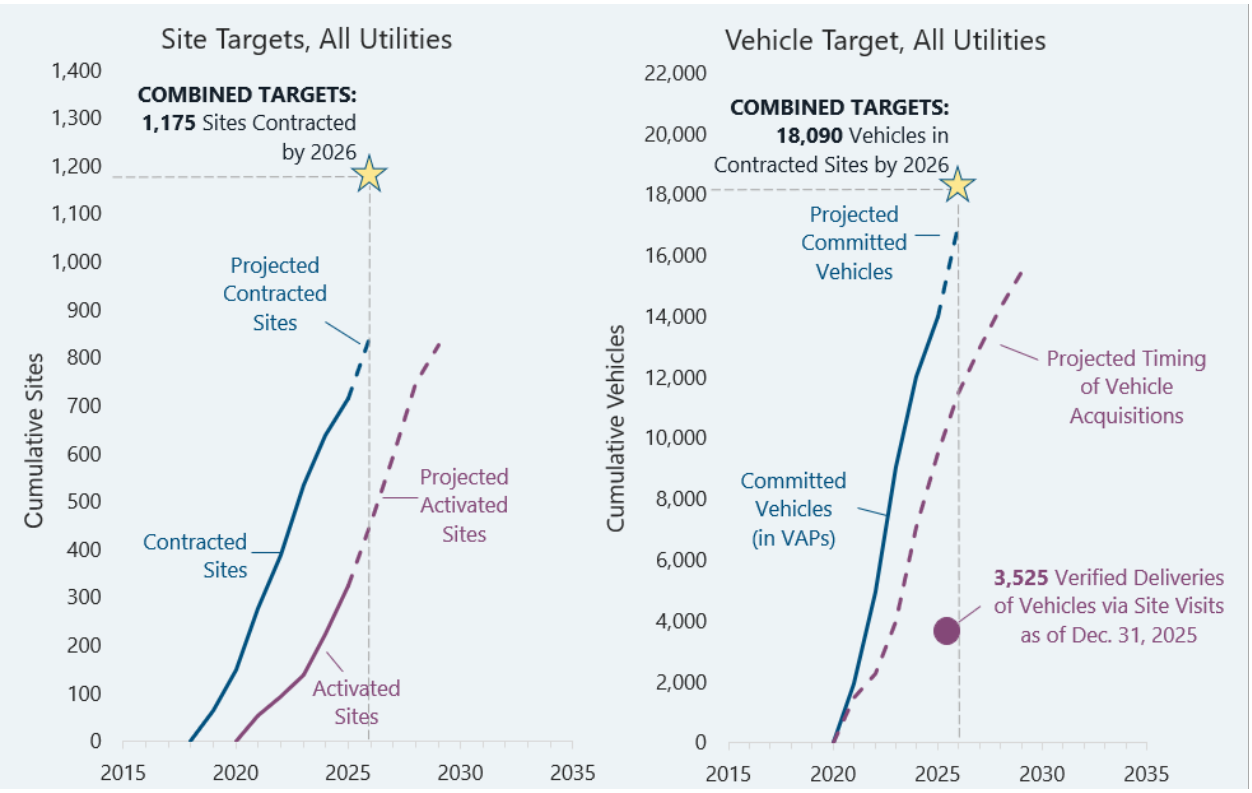
Preliminary lessons learned supported by findings are provided below by bundle. These lessons and findings were derived from program participants across most but not all market sectors.

1.3.1. Medium-Duty Heavy-Duty Bundle

> **LESSON 1.** MDHD programs are having a meaningful impact on EV adoption, and the number of vehicles supported may reach originating Decision expectations.

2025 saw the highest number of sites activated across program years, with 101 sites and 1,931 charging ports that can support a planned 2,790 EVs. This brings the total PTD sites across all Utility MDHD programs to 322 activated sites, with 5,532 charging ports that can support all 8,715 vehicles on customer VAPs. When all programs are aggregated, the Evaluation team expects that the Utilities will meet the combined *vehicle* targets in 2026 but fall short of the combined *site* targets (Figure 1).

Figure 1. Utility Program Progress Toward Site and Vehicle Targets



In 2025, SCE activated 29 new sites with 445 charging ports to support 909 vehicles based on customer VAPs in the Charge Ready Transport program, bringing the total activated PTD sites to 115, with 2,014 charging ports to support 3,891 vehicles. The 260 contracts signed in the program to date meet 52% of the program's revised per se reasonableness goal of 500 sites and would support 5,296 vehicles, meeting 62% of the program's per se reasonableness goal of 8,490 additional vehicles electrified.

In 2025, PG&E activated 60 new sites with 1,311 charging ports to support 1,644 vehicles based on customer VAPs in the EV Fleet program, bringing totals to 170 activated sites with 3,040 charging ports that can support 3,976 vehicles. The 393 contracts signed in the EV Fleet program to date could support 7,270 MDHD vehicles, exceeding the program's per se reasonableness goals of 375 sites and 6,500 vehicles electrified.

In 2025, SDG&E activated 12 new sites with 175 charging ports to support 237 vehicles based on customer VAPs in the PYDFF program, bringing the PTD site total to 37 activated sites with 478 charging ports to support 929 vehicles. The 62 contracts signed in the program to date satisfy 21% of the program's per se reasonableness goal of 300 signed contracts and would support 1,451 vehicles, which would meet 48% of the goal of 3,000 vehicles.

Recommendation 1.1: Program participation has been constrained due to the economic costs and risks associated with transitioning fleets to a new technology, the challenge of matching vehicle acquisition timelines to site activation timelines and commercial property lease durations, and regulatory uncertainty. Therefore, providing monetary incentives, including BTM incentives, EVSE rebates, and favorable Utility rates is recommended to continue customer adoption. Results from the UC Davis Truck Choice Model (TCM) indicate that in 2030, a BTM incentive that covers 100% of BTM equipment and installation costs will result in over 100% higher EV adoption in some MDHD market sectors than offering no BTM incentive. The model results suggest similar impacts in 2035 when the costs to purchase an EV are assumed to be lower. Looking ahead, given the uncertainty around the State of California's Funding Cycle 1 (FC1), BTM incentives will be critical to MDHD EV uptake.

LESSON 2. The average site cost increased for SCE and SDG&E programs as larger sites came online, and decreased for PG&E, which showed a shift to smaller sites.

For the SCE Charge Ready Transport program, the average installed capacity per site through 2025 was 1,033 kW compared with 758 kW through 2024, showing a shift to larger sites. The average all-in costs paid by the customer and SCE rose to $869,600 in the program to date, up from $802,698 through 2024. SCE spending on TTM and BTM was $44,782 per vehicle and $1,119 per kilowatt of charging capacity installed for PTD sites through 2025, compared with costs of $36,450 per vehicle and $1,158 per kilowatt installed for PTD sites through 2024.

For the PG&E EV Fleet program, the average installed capacity per site through 2025 was 660 kW compared with 765 kW through 2024, as smaller sites came online in 2025. All-in costs paid by the customer and PG&E varied widely between sites, with an average of $810,420 per site in the program to date through 2025, up from $724,248 through 2024. PG&E spending on TTM and BTM costs was $34,409 per vehicle and $1,317 per kilowatt of charging capacity installed for PTD sites through 2025, which were higher than cost of $24,931 per vehicle and lower than $1,508 per kilowatt through 2024.

For the SDG&E PYDFF program, the average installed capacity per PTD site through 2025 was 349 kW, compared with 383 kW through 2024. The average all in-cost per site paid by the customer and SDG&E decreased significantly to $735,949 through 2025 from $890,741 through 2024. SDG&E spending on TTM and BTM was $37,513 per vehicle and $1,951 per kilowatt of charging capacity installed for PTD sites through 2025, which is a significant increase per vehicle of $24,262 in 2024, but a decrease in spending per kilowatt installed of $2,135.

A strong relationship exists between sites' installed capacity and cost per installed kilowatt as shown in Figure 2 with larger sites showing a lower cost per kilowatt in general than smaller sites.

Figure 2. TTM and BTM Cost versus Installed Site Capacity for PTD Sites

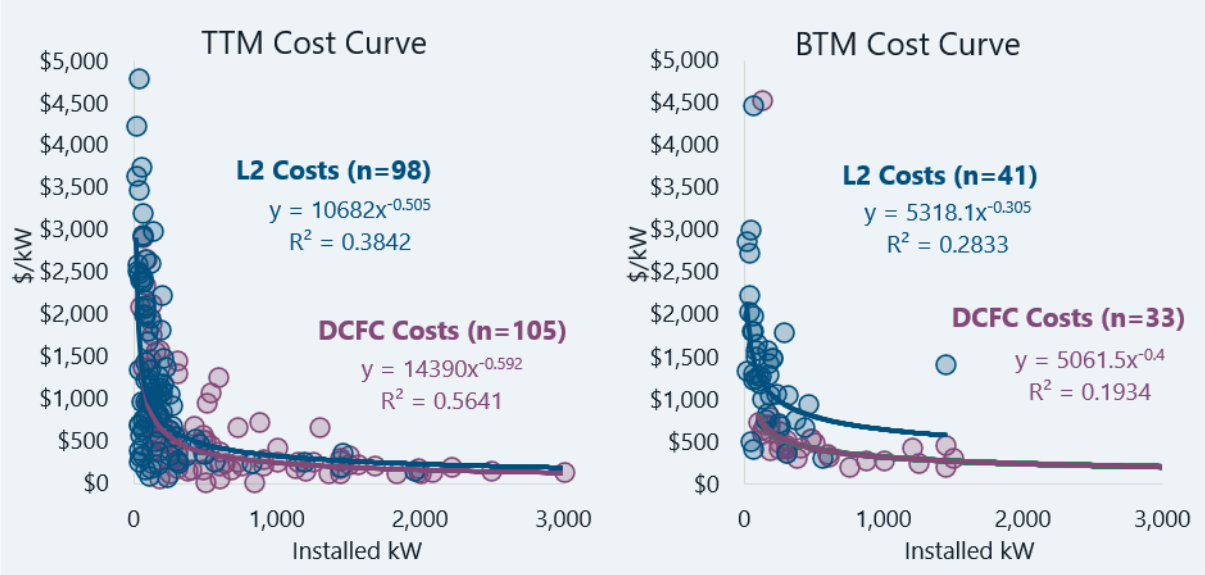


Table 4 provides both a simple average and a weighted average of the costs for the three Utility MDHD programs for PTD sites through 2025. With the simple average, each site has the same influence on overall average costs regardless of the site's installed kilowatts. Weighting by installed capacity provides greater insight because sites with larger installed capacity have more influence on the analysis.

Table 4. MDHD PTD Site Costs Using Simple and Weighted Averages

Utility Program	TTM + BTM Site Cost		TTM + BTM Site Cost per Kilowatt	
	Simple Average	Weighted Average	Simple Average	Weighted Average
SCE Charge Ready Transport	$467,715	$1,154,345	$1,119	$453
PG&E EV Fleet	$275,712	$535,489	$1,317	$417
SDG&E PYDFF	$401,565	$675,074	$1,951	$1,150
All MDHD Programs	$346,558	$800,113	$1,328	$471

Across all Utility MDHD programs, the simple average cost per site for TTM and BTM was $346,558, compared with the weighted average cost of $800,113. The simple average cost per kilowatt installed was $1,328, compared with the weighted average cost of $471. This shows that when weighting by installed capacity, average total site costs are higher and average cost per kilowatt is lower than when calculating a simple average, consistent with Figure 2.

LESSON 3. Utility spending on closed-out sites remains low, but nearly all remaining program funds have been reserved for contracted sites. Disadvantaged community (DAC) spending remains on target, and program-wide vehicle, and site targets may be met, but some individual Utility programs may fall short of goals.

In total the three Utilities have spent $188.1 million of an approved budget of $686 million, or approximately 27%, across MDHD programs to date. However, these totals represent spending on only financially closed-out sites and do not include funding that has been reserved for contracted sites. Currently, all Utilities are exceeding their DAC goals across MDHD programs.

SCE spent $14.5 million on closed-out sites in 2025, bringing total program spending to $64.5 million of an approved budget of $342.6 million, or 19% of total funds. Sixty-seven percent of Charge Ready Transport program spending has been on sites in DACs, exceeding the 40% program target. In both EY2025 and the program to date, nearly 70% of sites, charging ports, and vehicles are in DACs. SCE does not expect the Charge Ready Transport program budget to be fully subscribed in 2026.

PG&E spent $19.5 million of the EV Fleet program budget on closed-out sites in 2025, bringing total spending to $89.4 million of the approved program budget of $236.3 million, or 38% of available funding. Forty-two percent of the EV Fleet program spending has been on sites in DACs, exceeding the 25% program target. In both EY2025 and the program to date, more than 35% of sites, charging ports, and vehicles are located in DACs. PG&E has reported that the EV Fleet program budget is fully subscribed with the current pipeline of applications in pre-assessment.

SDG&E spent $7.9 million of the PYDFF program budget on closed-out sites in 2025, bringing total spending to $34.2 million of the approved budget of $107.4 million, or 32% of available funding. Forty-four percent of the PYDFF program spending has been on sites in DACs, exceeding the 30% program target. In both EY2025 and the program to date, more than 30% of sites, charging ports, and vehicles are located in DACs. SDG&E does not expect the PYDFF program budget to be fully subscribed in 2026.

Recommendation 3.1: Because Utilities report on financially closed out sites rather than on all sites in the program pipelines, reported spending is still relatively low compared with approved program budgets. It would be beneficial for the Utilities to share estimated spending for projects not yet financially closed out, both to better understand program performance and to indicate availability of program funds for future applicants. Greater transparency and timeliness of actual spending data promotes public trust in the Utility programs and potentially allows for a more engaged set of stakeholders within California and elsewhere.

Recommendation 3.2: As a response to an EY2023 recommendation, SCE and SDG&E have developed processes to proactively track activated sites' progress toward fulfilling their VAPs subsequent to site visits to ensure that program participants are meeting their obligations. Ensuring that VAPs are fulfilled will contribute to improved program performance with respect to energy consumption, petroleum displacement, emissions reductions, and health impacts. The Evaluation Team recommends that PG&E undertake a similar process in EY2026.

LESSON 4. Installed capacity and demand continues to grow, but less than 20% of fleets are implementing load management. Many fleets could entirely shift charging from on-peak to off-peak periods without impacting operations, representing millions of dollars in potential savings and significantly reduced peak demand.

Installed capacity grew by nearly 72 MW in 2025 across all Utility MDHD programs, bringing total installed charging capacity for PTD sites to nearly 237 MW. Total energy consumption also grew significantly, with more than 87 MWh consumed in 2025, nearly 50% of PTD site consumption of 176 MWh in the programs to date. Peak demand (not concurrent) was 42 MW, or approximately 18% of total installed charging capacity, indicating that sites have significant opportunity to increase charging utilization.

Across all Utility MDHD programs, only 57 of the 311 operational sites (18%) exhibited strong use of load management, but these 57 sites account for approximately 50% of total consumption across program sites.

Adoption of load management by fleets would offer the opportunity for significant savings on monthly energy costs by shifting charging from the peak 4 p.m. to 9 p.m. period. Across Utility MDHD programs, 23% of all energy consumed in the heavy-duty vehicle sector, 47% in the medium-duty vehicle sector, 59% in the school bus sector and 21% in the transit bus sector has enough charging flexibility to be entirely shifted from peak to off-peak periods without impacting fleet operations.

Significant Opportunity for Savings

Across all MDHD programs, all sites combined could save more than an estimated $4.5 million annually, representing a 27% cost reduction and a 14% reduction in GHG emissions by shifting consumption to off-peak periods.

While rates vary across utilities, the best performing load-managed sites across market sectors are able to achieve monthly bills with an energy cost near $0.15/kWh, and 73% of all load-managed billing months have an energy cost of less than $0.30/kWh. For non-load-managed sites, only 35% of billing months have an energy cost of less than $0.30/kWh, 40% of billing months are between $0.30/kWh and $0.50/kWh, and over 10% of billing months have an energy cost greater than $0.80/kWh.

Across the medium-duty vehicle, heavy-duty vehicle, school bus, and transit bus market sectors, an estimated 65% of fleets could save 20% or more annually through optimized charging, and over 40% could save over 30% annually. For example, half of school bus sites could save over $5,000 annually and one-third could save over $10,000 annually (Figure 3).

Figure 3. Available Annual Dollar and Proportional Utility Bill Savings Modeling



Each bar represents one site. Bar colors indicate the site's market sector, and bar shades show its use of load management.

In deep dive interviews with 40 fleet managers representing 60 sites that have not implemented load management, two primary barriers became evident.

- **Limited awareness:** Many fleet managers are aware of the service reliability of their EVs and charging stations but are unaware of their actual energy usage and utility bills, the relationship between the two, and potential ways to lower their bills.
- **Limited support services**: Not all network service providers (NSPs) provide load management software to fleets, and even fewer provide consistent customer support to help fleets initiate and maintain load management. Because fleets sign multiyear contracts, fleets can miss out on minimizing costs for many years.

The main solution identified by fleet managers was more NSP support. Fleet managers also reported wanting ongoing information about their energy and billing trends and achievable energy costs.

Recommendation 4.1: Utilities should consider offering annual follow-up technical assistance to fleet managers and site staff familiar with utility billing to provide both groups with charging data and ensure that fleet managers of small and medium-size fleets in particular have direct access to monthly electricity bills. Providing fleet managers with the opportunity to more accurately understand the financial impacts of time-of-use (TOU) rates may influence them to reduce operational costs by using load management. To maximize benefits to customers and ratepayers, new EV fleet operators need to begin load management quickly upon site and vehicle commissioning; many observed that fleets have operated for a year or more before load management was adopted.

LESSON 5. Not all NSPs offer load management, and only two operators stand out in terms of customer load management performance.

A total of 30 NSPs service customers across Utility MDHD programs, with 18 of these NSPs confirmed as offering load management capabilities. Two of these 18 NSPs (FlipTurn and BP Pulse)[5] support 10 or more sites, over 60% of which (82% and 64% respectively) exhibit load management. Both NSPs have also been reported in deep dive interviews as providing strong customer service regarding load management. Only one other NSP serving more than 10 customer sites has more than 30% of sites exhibiting load management, and the majority of NSPs are below 20%, regardless of number of sites they serve.

Recommendation 5.1: Utilities should consider mandating that all new EVSE technology included in the approved product list (APL) be capable of performing basic load management services, such as rules-based charging.[6] Utilities should also consider requiring all NSPs to offer load management capabilities to allow fleet operators to implement more cost-effective charging behavior. The Evaluation Team found that some NSPs offer load management capabilities, but these capabilities are not always at the service level in which fleet operators had chosen to enroll. The Evaluation Team does not recommend mandating that fleet operators enroll in more costly NSP plans.

Recommendation 5.2: Utilities should consider requiring NSPs to proactively provide support to customers to initiate load management. Utilities can also consider enabling customers to switch NSPs due to underperformance without creating a financial burden to the customer through their program design. This can be accomplished by structuring the contracts with NSPs to include regular reimbursement based on performance metrics rather than up-front multiyear payments.

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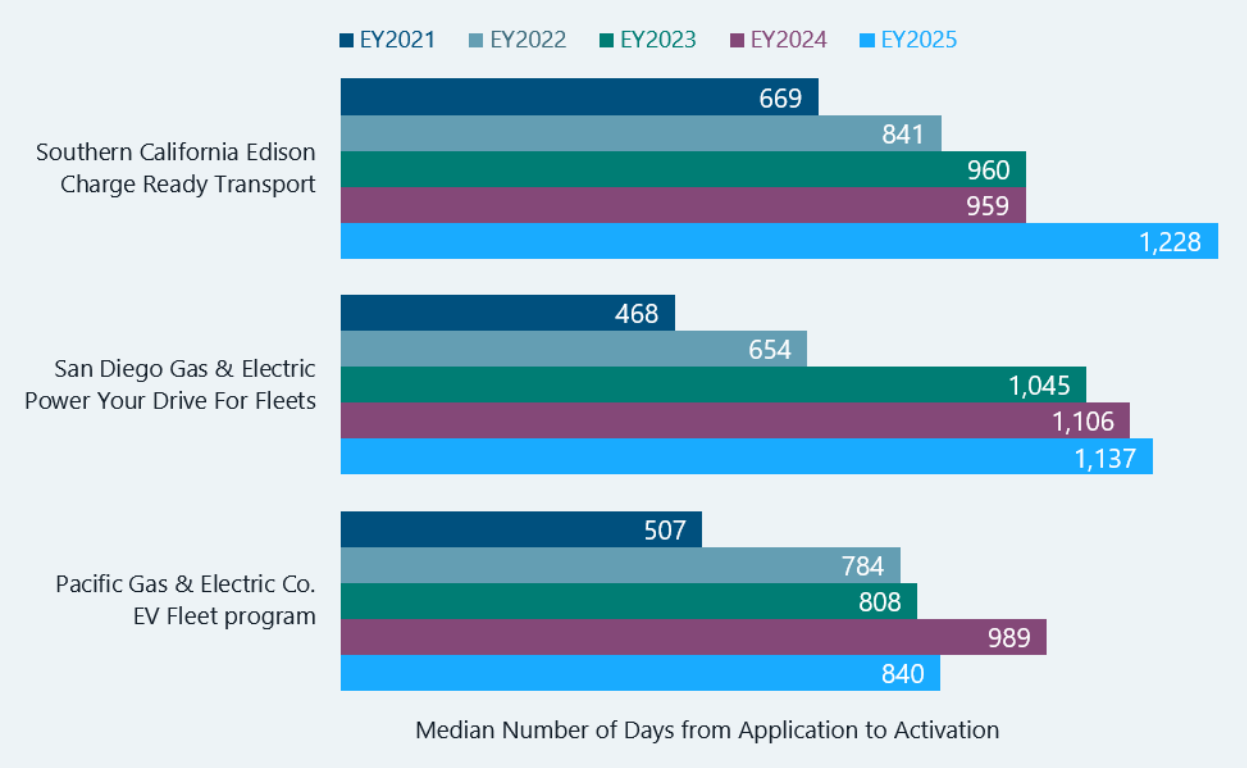
5 As of August 2026, BP Pulse is winding down its presence in the U.S. market.

6 Rules-based charging refers to a charging strategy that utilizes predefined rules or algorithms to determine when and how to charge a device or system

LESSON 6. Overall activation timelines based on activation year continued to increase for SCE and SDG&E as large sites came online, while timelines for PG&E decreased with its shift to smaller sites. However, assessing timelines by application year shows that timelines are decreasing on average across Utilities.

As presented in Figure 4, based on activation year, the duration from application to activation varied substantially between the Utilities. SCE reached 1,228 days in 2025, up from 959 in 2024 and SDG&E rose from 1,106 in EY2024 to 1,137 in EY2025, while PG&E fell from 989 days in EY2024 to 840 days in EY2025. As in previous years, the design and permitting phase was the longest phase across programs, with an average length of 466 days, or 47% of the total average activation timeline of 1,001 days across the three programs. This is primarily a reflection of a general shift to larger sites for both SCE and SDG&E and to smaller sites for PG&E.

Figure 4. Median Calendar Days from Application to Activation by Evaluation Year



It is important to note that larger, more complex sites inherently take longer to complete; as a result these sites are activated in later program evaluation years, which may cause overall activation timelines to increase throughout the evaluation period. To address this issue and better understand trends across programs, in 2025 the Evaluation Team also examined the activation timeline of sites based upon application year. Table 5 presents median calendar days by CPUC program phase grouped by application

year across the medium-duty vehicle, heavy-duty vehicle, school bus, and transit bus market sectors. Analyses by application year versus by activation year have two major differences:

- Sites in Utility MDHD programs typically have activation timelines of two years or more. Accordingly, no sites that applied to the program in 2024 or 2025 have been activated, and therefore no data has been presented for any of those sites. However, sites that entered the program in 2019 and 2020 are represented in Table 5, but not in Figure 4, which starts timeline analysis in EY2021.
- Due to the number of sites in each market sector, Table 5 compiles data from only four market sectors (heavy-duty vehicle, medium-duty vehicle, transit bus, and school bus), while Figure 4 includes data from all market sectors.

Table 5. Median Calendar Days by Year of Application and Program Phase for PTD Sites in Four Market Sectors

CPUC Program Phase	Median Calendar Days [a]				
	2019	2020	2021	2022	2023
Application Review	32	34	61	75	55
Site Assessment	37	40	29	38	47
Contract Issuance	43	45	42	32	41
Design and Permitting	312	361	455	429	476
Construction Complete	102	118	131	46	20
Activation	59	17	24	22	16
Start to Finish	863	863	979	896	734

[a] 2024 and 2025 are not included as no applications received in those years across Utility programs had been activated as of December 31, 2025.

The analysis of median calendar days by application year reveals three key findings:

- The duration between site application and activation peaked for customers who submitted applications in 2021 and has declined for more recent applicants.
- Design and permitting continues to be the program phase with the longest duration.
- Overall, the duration of the construction and activation phases has decreased since 2021, indicating improved efficiency once sites advance through the design and permitting phase.

Analyzing activation timelines by application year may inherently produce shorter timelines because sites with longer durations may not yet be activated. For example, a site that entered the program in 2022 and takes four years to complete would not be included in the EY2025 analysis, whereas a site activated in the same year that was completed in two years would be included. However, when viewed together, analysis by application year and activation year provide a more balanced view of overall program performance than looking at only one or the other.

> **LESSON 7.** Utility MDHD program sites continue to displace petroleum, reduce GHG and local emissions, and achieve health impacts.

Combined, the MDHD sites have displaced nearly fifteen million gallons of petroleum in the program to date, with nearly five million in the heavy-duty vehicle market sector. Specifically, the SCE Charge Ready Transport sites account for over eight million gallons, PG&E EV Fleet sites for nearly six million gallons; and SDG&E PYDFF sites for over one million gallons. PTD sites across the programs collectively reduced over 120,000 MT of GHG emissions, with just over 40,000 MT within the heavy-duty vehicle market sector. These sites all positively contributed to lowering local emissions, with CO impacts being the most prominent, achieving a reduction of more than 720,000 kg to date. For SCE, the total monetized health benefits range from $6,247,660 to $8,147,824 with 31% occurring in DACs. For PG&E, the total monetized health benefits range from $4,070,682 to $5,421,073 with 14% occurring in DACs, and for SDG&E, the total monetized health benefits range from $703,385 to $925,677, with 18% occurring in DACs.

1.3.2. Public Charging Bundle

All Public Charging Programs

> **LESSON 1.** The Schools and Parks Pilots sites and the EV Fast Charge program sites continue to displace petroleum, reduce GHG and local emissions, and achieve health impacts overall and within DACs.

Combined, the Schools and Parks Pilots PTD sites have displaced more than one million gallons of petroleum, with between 49% and 70% of the impact occurring within DACs. In addition, the PTD sites across the pilots collectively reduced over 4,500 MT of GHG emissions. These sites also contributed to lowering local emissions, with CO impacts being the most prominent with a reduction of over 24,000 kg to date. Finally, the sites accounted for between 15% and 27% of the health benefits in DACs with a total monetized health benefits range from $5,895 to $28,240.

> **LESSON 2.** The Schools and Parks Pilots' sites and the EV Fast Charge program sites continue to promote regional EV adoption.

The SDG&E Schools and Parks Pilots, SCE and PG&E Schools Pilot, and PG&E EV Fast Charge program contributed to EV adoption by nearly 600 households neighboring sponsored infrastructure. SDG&E's investments in the Schools and Parks Pilots' public charging infrastructure had an economically meaningful impact on EV ownership, leading to an increase of 150 EVs for the Schools Pilot and 241 EVs for the Parks Pilot to date. As in past years, the impact of the SDG&E Schools Pilot was greater than the impact of the SDG&E Parks Pilot, as more charging facilities are in schools than in parks and the school sites are easier for the public to access than the park sites. The SCE and PG&E Schools Pilots also positively contributed to EV adoption by households neighboring the infrastructure with 85 EVs attributed to SCE and 41 EVs attributed to PG&E to date. The PG&E EV Fast Charge program also continued to positively contribute to EV adoption by households neighboring the infrastructure relative to baseline registrations, with 65 EVs to date.

LESSON 3. Many of the Schools and Parks Pilots and EV Fast Charge program sites have an opportunity to support grid integration by passing on TOU pricing to EV drivers.

SDG&E owns the EV chargers at Schools and Parks Pilot sites with their NSP acting as a customer of record, which allows them to pass on the TOU pricing to EV drivers at all of their sites. SCE and PG&E Schools Pilots and PG&E EV Fast Charge program sites have customer-owned EV chargers with pricing set by customers, resulting in 40% of PG&E (6 of 15 sites with displayed pricing) and 44% of SCE (11 of 25 sites with displayed pricing) Schools Pilot sites along with 23% of PG&E EV Fast Charge sites (7 of 30 sites with displayed pricing) charging TOU rates to EV drivers.

Recommendation 3.1: While the pricing for SCE and PG&E sites is up to site hosts to set, we recommend that the Utilities encourage site hosts that are not passing on TOU pricing to EV drivers to do so. For SCE, PG&E, and Liberty Parks sites that have not yet been activated, we recommend that these Utilities consider offering TOU pricing to EV drivers if this is within the Utilities' control and otherwise encourage sites hosts to offer TOU pricing. Providing a TOU pricing structure for EV drivers would be in line with Utility tariffs and would pass on the pricing signals to EV drivers by alerting them to when EV charging is less grid friendly and more costly to the site hosts.

Schools and Parks Pilots

LESSON 1. As new sites are activated in the Schools and Parks Pilots, total consumption is increasing.

The eight sites activated in the SCE Schools Pilot added 550 kW of charging capacity in 2025, bringing total installed capacity to 1,750 kW. Overall energy consumption increased by 40% to 358 MWh in 2025 from 252 MWh in 2024, while demand peaked at 322 kW, up from 215 kW in 2024. The three new sites activated in the PG&E EV Charge Schools Pilot added 144 kW of charging capacity in 2025, bringing total installed capacity to 633 kW. Overall energy consumption increased by 48% to 233 MWh in 2025, up from 150 MWh in 2024, while demand peaked at 161 kW, similar to 169 kW in 2024. The seven new sites activated in the SDG&E Schools Pilot added 288 kW of charging capacity in 2025, bringing total installed capacity to 1,790 kW. Overall energy consumption increased by 48% to 656 MWh in 2025, up from 450 MWh in 2024, while demand peaked at 483 kW, up from 381 kW in 2024. While no new sites were activated in the SDG&E Parks pilot, overall energy consumption increased by 20% to 570 MWh in 2025, up from 480 MWh in 2024.

LESSON 2. Utilization of Schools and Parks Pilot sites is increasing, and sites show additional charger utilization outside of expected charging hours, indicating use by local communities.

Over 40,000 charging sessions have been completed at SCE Schools Pilot sites to date, with approximately one-third of sessions occurring in EY2025. Nearly 19,600 charging sessions have been completed at PG&E

EV Charge Schools Pilot sites to date, with approximately 40% of sessions occurring in EY2025. Nearly 70,000 charging sessions have been completed at SDG&E Schools Pilot sites, with approximately 43% of sessions occurring in EY2025. Nearly 65,000 charging sessions have been completed at SDG&E Parks Pilot sites to date, with approximately 34% occurring in EY2025.

Most Schools Pilot sites operate on a typical workplace charging schedule, with peaks in the morning and very limited utilization during evenings and weekends. However, across each of the Schools Pilots, unexpected charging has been observed outside of school hours in the evenings and on weekends. This indicates that some Schools Pilot sites are being used by members of the local community. Similarly, significant unexpected overnight charging was observed at the SDG&E Parks Pilot sites, which may mean that these sites are supporting EV drivers in nearby multiunit dwellings.

> **Recommendation 2.1:** Utilities should encourage all Schools Pilot sites to consider allowing EVSE to be used during non-school hours by members of the local community, where appropriate. Enabling use outside of typical workplace charging schedules can increase charger utilization and support local EV adoption.

EV Fast Charge

> **LESSON 1.** As new sites are activated in the PG&E EV Fast Charge program, total consumption and demand, delivered energy per charging session, and repeated use of chargers are all increasing, indicating that the program is meeting EV driver charging needs.

The three new sites in the PG&E EV Fast Charge program added 1,020 kW in 2025, bringing total installed capacity to 13,590 kW. Overall energy consumption increased by 52% to 5,625 MWh in 2025, up from 3,703 MWh in 2024. The amount of energy dispensed per charging session has also grown, with 17% of all sessions dispensing over 50 kWh in 2025, compared with 15% in 2024. Fifty percent of drivers using EV Fast Charge program sites appear to be repeat customers with five or more charging sessions in 2025.

1.4. Structure of Report

The evaluation report is organized into the following sections:

- **Chapter 1.** Executive Summary
- **Chapter 2.** Introduction
- **Chapter 3.** Statewide Findings
- **Chapter 4.** SCE Programs: Charge Ready Transport, Schools and Parks Pilots
- **Chapter 5.** PG&E Programs: EV Fleet, Schools and Parks Pilots, and EV Fast Charge
- **Chapter 6.** SDG&E Programs: PYDFF, Schools and Parks Pilots
- **Chapter 7.** Liberty Utilities Programs: Schools and Parks Pilots

- **Appendix A.** Deep Dives
- **Appendix B.** Methodology
- **Appendix C.** Data Collection Instruments

Each of the program-specific sections in Chapter 4 through Chapter 7 contain the same three sections:

- **Overview:** Describes the program offering including implementation, performance metrics, materials and budget summary, and timeline.
- **Findings:** Analysis results from in-depth interviews, surveys, site visits, and deep dives regarding co-costs and co-benefits, site costs, EV adoption, grid impacts, petroleum displacement, GHG emissions and criteria pollutant reductions, health impacts, and net impacts, as appropriate by bundle.
- **Lessons Learned:** Varies according to the needs of each evaluation bundle.

2. Introduction

In support of the transportation electrification goals of the SB 350 Clean Energy and Pollution Reduction Act of 2015 and ABs 1082 and 1083, the CPUC issued decisions in 2018 and 2019 authorizing investment in 12 Utility programs designed to spur adoption of LDV and MDHD vehicle electrification among fleets and households. The programs support both TTM and BTM EV charging infrastructure, along with EVSE. Programs cover 100% of the TTM cost and vary in their level of support for BTM and EVSE. Approximately 90% of the funding for these 12 programs is for MDHD EVs as shown in Table 6.

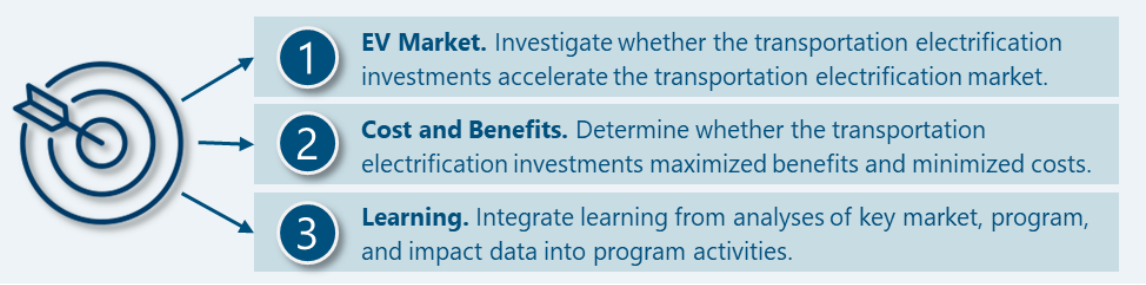
Table 6. Summary of Utility Programs

Utility	Program	Description	Decision	Public Charging Budget	MDHD Budget
SCE	Charge Ready Transport	TTM and some or all of the BTM infrastructure up to the charging station for MDHD fleets. Additional rebates for charging stations are available for certain fleets.	18-05-040		$342.6M
	Schools Pilot	Installation of approximately 250 Level 1 (L1) and Level 2 (L2) charging ports at 40 K–12 schools.	19-11-017	$9.9M	
	Parks Pilot	Installation of approximately 120 L2 charging stations, 10 DCFC ports, and an optional 15 mobile stations across 27 state parks and beaches.	19-11-017	$9.9M	
Total SCE Approved Budget				**$19.8M**	**$342.6M**
Percentage of Total SCE Approved Budget				**5%**	**95%**
PG&E	EV Fleet	TTM and some or all BTM infrastructure up to the charging station for MDHD fleets. Additional rebates for charging stations are available for certain fleets.	18-05-040		$236.3M
	Schools Pilot	Installation of four or six L2 charging ports at 22 schools.	19-11-017	$5.8M	
	Parks Pilot	Installation of L2 and DCFC ports at state parks and beaches.	19-11-017	$5.5M	
	EV Fast Charge	Make-ready infrastructure of 30–40 DCFC sites and rebates for EVSE.	18-05-040	$22.4M	
Total PG&E Approved Budget				**$33.7M**	**$236.3M**
Percentage of Total PG&E Approved Budget				**12%**	**88%**
SDG&E	PYDFF	TTM and some or all BTM infrastructure up to the charging station for MDHD fleets. Additional rebates for charging stations are available for certain fleets.	19-08-026		$107.4M
	Schools Pilot	Installation of and incentives for installing 184 L2 and 12 DCFC ports at 30 educational institutions.	19-11-017	$9.9M	
	Parks Pilot	Installation of 74 light-duty public charging ports in 12 state parks and beaches within SDG&E's service territory and 66 light-duty public charging ports at 10 city and county park sites.	19-11-017	$8.8M	
Total SDG&E Approved Budget				**$18.7**	**$107.4M**
Percentage of Total SDG&E Approved Budget				**15%**	**85%**
Liberty	Schools Pilot	Up to 56 L2 and DCFC ports at 17 schools.	19-11-017	$3.9M	
	Parks Pilot	Five dual-pedestal EVSE at three sites.	19-11-017	$0.8M	
Total Liberty Approved Budget				**$4.7M**	**$0**
Percentage of Total Liberty Approved Budget				**100%**	**0%**
Total Approved Budget				**$76.9M**	**$686.3M**
Percentage of Total Approved Budget				**10%**	**90%**

2.1. Evaluation Framework

Per the originating CPUC decisions,[7] this evaluation has three overarching objectives (Figure 5).

Figure 5. Evaluation Objectives



To fulfill these objectives, the Evaluation Team conducted a variety of data collection and analysis activities for the MDHD and public charging programs, summarized in Table 7.

Table 7. Data Collection and Analysis Activities

Type	Activity	MDHD	Public Charging
Data Collection	Program Data and Materials Analysis	●	●
	AMI/EVSP Data Analysis	●	●
	Site Visits	●	●
	Site Cost Data Analysis	●	●
	Monthly Customer Bill Analysis	●	●
	Market Data Analysis [a]	●	●
	Interviews	●	●
	Surveys	●	
	Delphi Panels	●	
Data Analysis	EV Adoption Regression		●
	Grid Impacts Analysis	●	●
	Counterfactual Development	●	●
	Petroleum Displacement Analysis	●	●
	GHG and Criteria Pollutant Analysis	●	●
	Health Impacts Analysis	●	●
	Site Cost Analysis	●	●
	Site Visits	●	●
	Co-Benefits and Co-Costs Analysis	●	
	Interviews/Survey Analysis	●	●
	Market Effects Analysis	●	

[a] Market data analysis includes new vehicle sales, charging statistics, and make-ready filings.

[7] CPUC Decision 18-05-040. docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF; CPUC Decision 19-11-017 docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K823/319823155.PDF; CPUC Decision 19-08-026 docs.cpuc.ca.gov/PublishedDocs/Published/G000/M311/K550/311550050.PDF

Figure 6 is a conceptual diagram of the impact of the Utilities' programs on the broader transformation of the EV market. Figure 6 aligns with other market transformation work in California.[8]

Figure 6. Conceptual Diagram Showing Program Impacts on EV Market

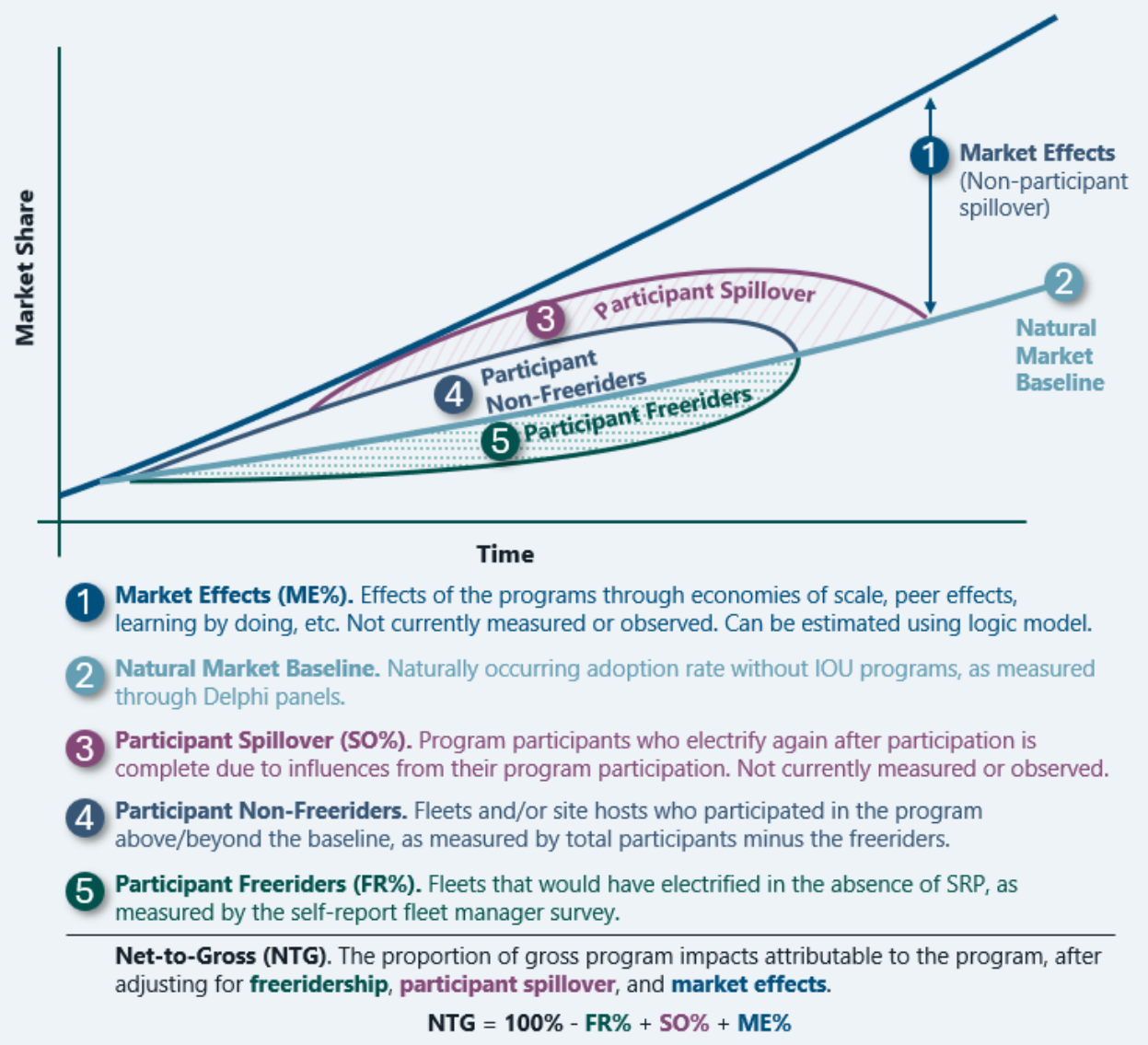


Figure 6 shows that over time the EV market share rises. Conceptually, the market share could be considered the percentage of new vehicle sales that are EVs. The light blue line (#2) is the naturally occurring baseline adoption curve. This is the adoption that would occur in the *absence* of the Utility programs, which grows over time because of the external market, policy, and behavioral factors.

[8] For an example, see CPUC (2023) California Market Transformation Evaluation Framework, Draft Version 2.0, August 2023.

The Utility programs have two types of participants. Participant non-freeriders (#4) are those who adopt EVs as a result of the Utility programs and appear above the natural market baseline. Participant freeriders (#5) are the subset of participants who would have adopted an EV in the absence of the Utility programs and are included in the natural baseline. Areas #4 and #5 sum to all participants of the Utility programs.

The participant spillover area (#3) represents program participants that install more ports following their participation in a Utility program. For example, a fleet that has a strong positive experience participating in one of the programs may continue adopting EVs after their participation is completed, leading to spillover. Finally, the programs spur broader market effects through increased learning, economies of scale, and peer effects which result in more EV charging infrastructure installed across the State of California and elsewhere (#1). The top blue line in Figure 6 represents EV adoption rates after accounting for all impacts of the Utility programs.

For MDHD programs, the Evaluation Team measures the natural market baseline (#1) through Delphi panels for individual market sectors. We estimate freeridership and spillover using a fleet manager survey which asks respondents about intentions. The Team then converts these responses to a net-to-gross (NTG) ratio. In our final Evaluation report in 2027, we will use the program to date NTG research to convert gross impacts into net impacts. For public charging programs, we do not estimate freeridership or spillover, nor do we calculate the NTG ratio. Instead we measure Utility program impact through a quasi-experiment involving an instrumental variable regression.

2.2. Light-Duty Market Landscape in California

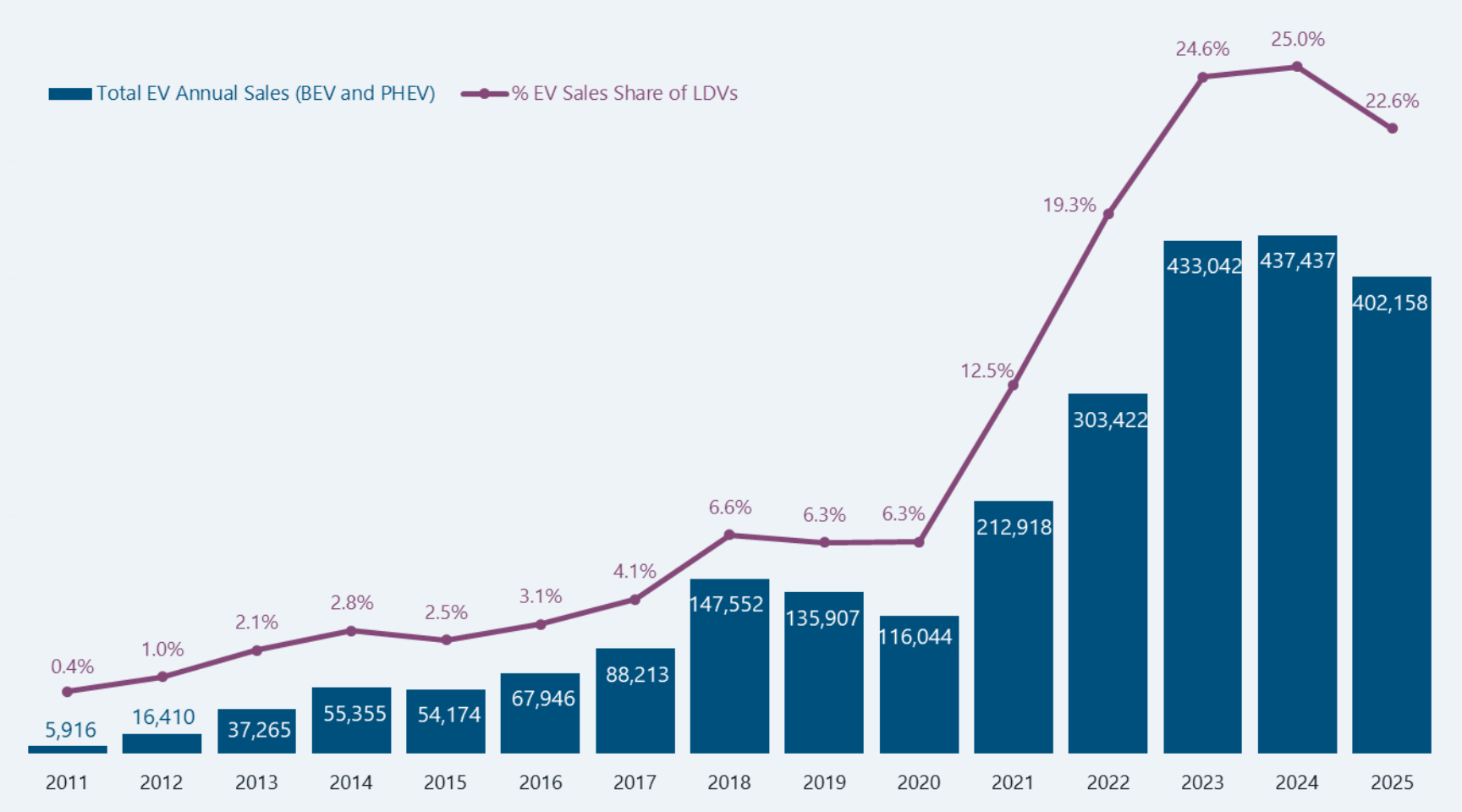
This section summarizes the market landscape in 2025 for the public charging programs, including Schools and Parks Pilots and PG&E's EV Fast Charge program. Vehicles of interest include Class 1–Class 2b vehicles, such as passenger sedans, small cargo vans, compact pickup trucks, small sport utility vehicles (SUVs), minivans, standard pickup trucks, and SUVs primarily driven by households. Some Class 2b vehicles that are used in fleets are counted as MDHD vehicle in the *MDHD Market Landscape in California* section.

2.2.1. Light-Duty Sales

Figure 7 shows the growth of annual sales of light-duty EVs in California, including battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). The bars represent annual sales, and the line represents annual sales share.[9]

[9] CEC staff performed a full audit of historical data in a May 2025 data update and updated the methodology to determine the sale of a new vehicle in the DMV source data.

Figure 7. 2011–2025 Light-Duty EV Annual Sales and Sales Share in California (Class 1–2b [a])



Source: Figure derived from California Energy Commission (2025). California Energy Commission Zero Emission Vehicle and Infrastructure Statistics. Data last updated 01/15/2026. Retrieved 4/8/2026 from www.energy.ca.gov/zevstats.

[a] The figure shows only household Class 1, 2a, and 2b EVs. For Class 2b, the Evaluation Team assumes that 50% of Ford F-150 Lightning Extended Range and GMC Silverado sales are in MDHD fleets, not households, and also categorizes cargo vans as MDHDs.

California's EV sales share decreased in 2025 following growth in prior years. Light-duty EVs accounted for 22.6% of all new LDV sales in 2025, down by 2.5 percentage points from 25.0% in 2024. Across the United States, the share of total new-vehicle sales that were EVs was 7.8% in 2025, down by 0.3 percentage points from 8.1% in 2024.[10]

2.2.2. Light-Duty Models

Table 8 shows the top 10 light-duty EVs sold in California in 2025, which account for 58% of the LDV EV market. Tesla Model Y was the sales leader, with 26% of the LDV EV market, losing 3.0 percentage points of the market share from 2024.

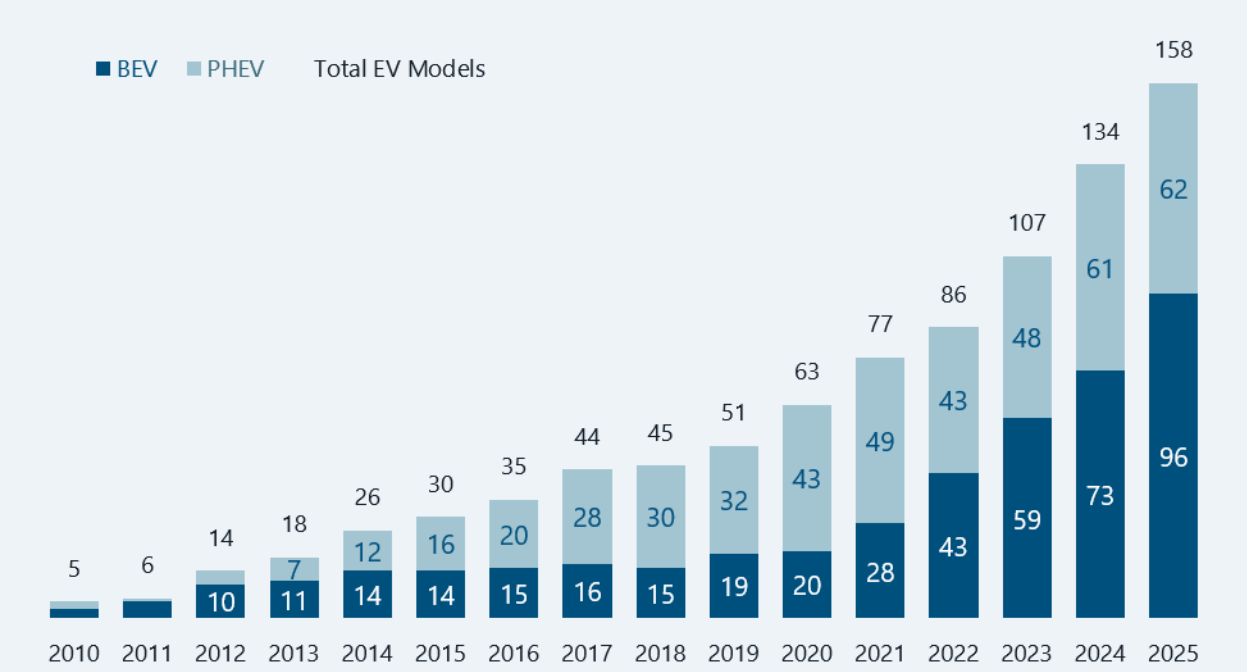
Table 8. Top 10 EVs in California, 2025 LDV Sales (Class 1–2b)

Rank	Make	Model	Type	2025 Light-Duty EV Sales	% of 2025 Light-Duty EV Sales
1	Tesla	Model Y	BEV	105,354	26%
2	Tesla	Model 3	BEV	50,910	13%
3	Hyundai	IONIQ 5	BEV	17,138	4%
4	Honda	Prologue	BEV	12,817	3%
5	Ford	Mustang Mach-E	BEV	11,458	3%
6	Chevrolet	Equinox EV	BEV	11,024	3%
7	Rivian	R1S	BEV	8,227	2%
8	BMW	i4	BEV	7,803	2%
9	Tesla	Cybertruck	BEV	6,134	2%
10	Volkswagen	ID.4	BEV	5,902	1%
Other 148 Makes/Models				**169,362**	**42%**
Total				406,129	100%

Figure 8 shows the number of unique zero-emission vehicle (ZEV) models offered in the California LDV market by year. In 2025, the California market had 158 unique models of light-duty EVs (BEVs and PHEVs), 24 more than in the previous year. The market maintained the trend from 2023 and 2024 of a shift toward BEV offerings (relative to PHEV offerings) with BEVs accounting for 60% of the available EV models.

[10] Cox Automotive, January 13, 2026. "Despite Q4 Collapse, 2025 EV Sales Decline Only 2% Versus 2024; Policy Shifts, New Product Set Stage for Next Chapter." www.coxautoinc.com/insights/q4-2025-ev-sales-report-commentary/

Figure 8. Unique Light-Duty EV Models for Sale in California (Class 1–2b)



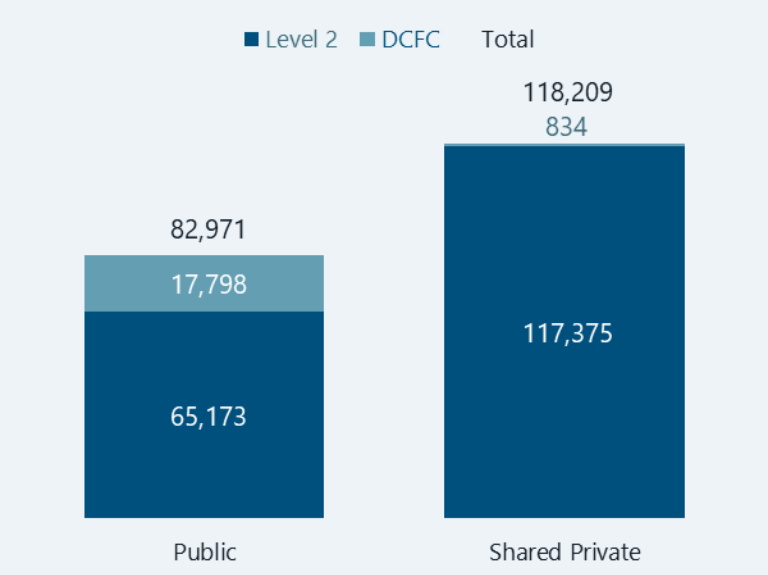
Source: Figure derived from California Energy Commission (2026). California Energy Commission Zero Emission Vehicle and Infrastructure Statistics. Data last updated 01/15/2026. Retrieved 04/14/2026 from www.energy.ca.gov/zevstats.

2.2.3. Charging Infrastructure Deployment

According to the California Energy Commission (CEC) ZEV Dashboard, there were 201,180 L2 and DCFC EV chargers for LDVs in California,[11] as of September 8, 2025, as can be seen in Figure 9. This includes 82,971 public chargers (65,173 L2 and 17,798 DCFC) and 118,209 shared private chargers (117,375 L2 and 834 DCFC). The CEC derives these numbers from multiple sources, including lists of public and shared private chargers by the Alternative Fuels Data Center (AFDC), PlugShare, and results from CEC surveys.

[11] The CEC defines the number of chargers by the number of vehicles that can charge simultaneously. For example, a Level 2 charger with two connectors that can charge two vehicles simultaneously is counted as two chargers. The U.S. Department of Energy (DOE) refers to these connectors as "ports."

Figure 9. LDV Chargers in California



2.3. MDHD Market Landscape in California

This section summarizes the market landscape in 2025 for electric MDHD vehicles. The three MDHD programs in this evaluation support charging infrastructure for a wide range of vehicle types, including both on-road and off-road vehicles. Table 9 provides an overview of the vehicle types used throughout the report, referred to as "market sectors" hereafter.

Table 9. Overview of Market Sectors

Category	Market Sector	Description
On-Road	Heavy-Duty Vehicle	Class 7–8 vehicles (including coach buses, large straight trucks, two-axle tractors, large straight trucks, tractors, and refuse trucks)
	Medium-Duty Vehicle	Class 2[a]–6 vehicles (including large panel vans, heavy-duty pickup trucks, straight trucks, step vans, small dump trucks, medium straight trucks, large maintenance trucks, and large step vans)
	School Bus	Class 4–8 school buses (including Type A, Type B, Type C, and Type D)
	Transit Bus	Class 7–8 transit buses (including standard buses, articulated buses, over-the-road buses, and double-decker buses for passenger transport)
	Truck Stop Electrification	High-power fast charging at truck stops enabling longer distance travel
Off-Road	Airport Ground Support Equipment (GSE)	Equipment used to service aircraft between flights (e.g., refueler, tugs/ tractors, potable water trucks)
	Forklift	Vehicle with a pronged device in front for lifting and carrying heavy loads
	Port Cargo Truck	Also known as a terminal tractor, low speed vehicle used to load, unload, move, and store cargo within seaports and terminals
	Transportation Refrigeration Unit (TRU)	Alternative to diesel refrigeration system, with the compressor driven by an electric motor

[a] Vehicles eligible for the MDHD programs are on-road vehicles with a gross vehicle weight exceeding 6,000 pounds (Class 2 to 8), including Class 2b cargo vans and light-medium trucks intended for fleet usage. Class 2 is included in the medium-duty vehicle SRP market sectors, which differs from the EPA's GVWR classification of Class 2 as LDVs.

MDHD Programs by the Numbers

As of December 31, 2025, participating fleets in the Utility programs accounted for…

- **322** activated MDHD sites, with 53% in DACs
- **5,489** ports in activated sites, with roughly 6,400 ports in the development pipeline (accounting for approximately **60% of the MDHD ports in California** reported by the CEC)
- **7,516** vehicles delivered or planned for delivery in the vehicle acquisition plan (VAP)
- **3,525** vehicles observed during Evaluation Team site visits (92% of which are on-road vehicles)

2.3.1. Medium-Duty and Heavy-Duty Vehicle Sales

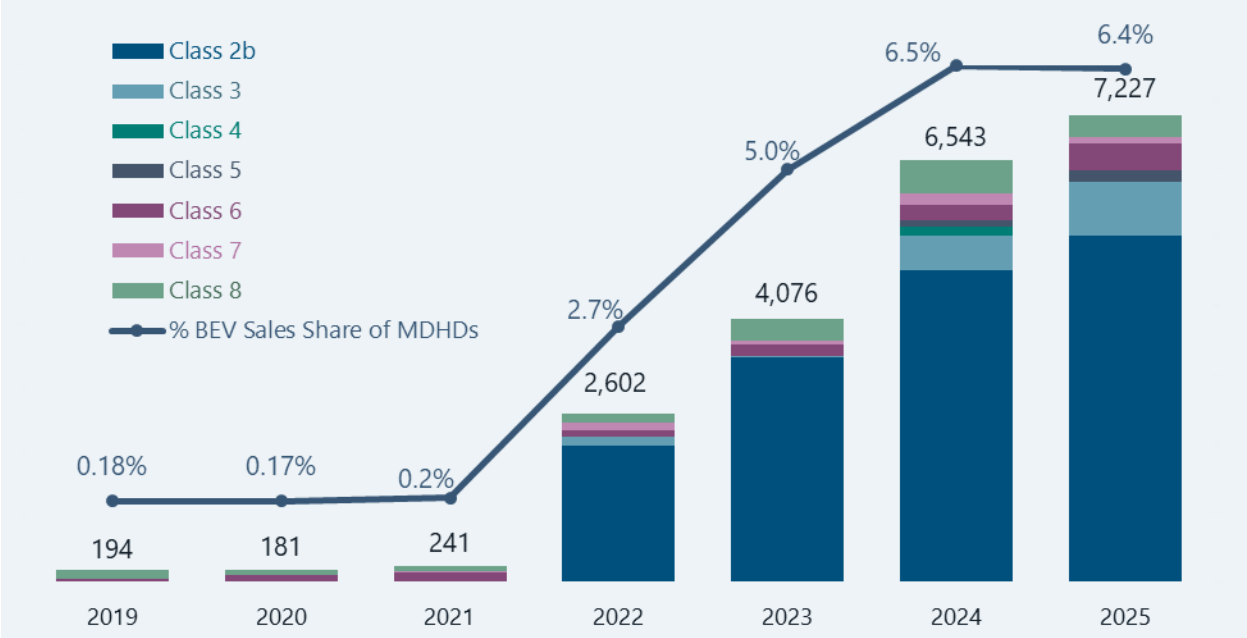
Figure 10 shows annual sales of MDHD fleet EVs in California between 2019 and 2025. Off-road MDHD vehicles are not shown in the figure because of limited data. Additionally, Class 2b vehicle counts reflect the Evaluation Team's best estimate of the number of vehicles in fleets versus household vehicles.

In 2025, the State of California added 7,227 new Class 2b to Class 8 fleet EVs, up from 6,543 EVs sold in 2024. Class 2b continues to lead sales across size classes with 5,371 EVs sold in 2025 (74% of all MDHD EV sales).[12,] Across Class 3 to Class 8, EV sales grew from 1,710 new EVs in 2024 to 1,856 new EVs in 2025.[13]

[12] According to Atlas Public Policy (originally from Experian); the Evaluation Team includes 50% of Ford F-150 Lightning and GMC Silverado's sales in the figures (the other 50% are assumed to be household vehicles). The Evaluation Team also excludes Rivian R1T, Rivian R1S, Cadillac Escalade IQ, Hummer EV, Sierra EV, and Tesla Cybertruck, assuming these vehicles are 100% household vehicles.

[13] Vehicle sales figures are not comparable to those in the California Energy Commission (CEC) MDHD dashboard because the Evaluation Team removes household vehicles, while the CEC does not.

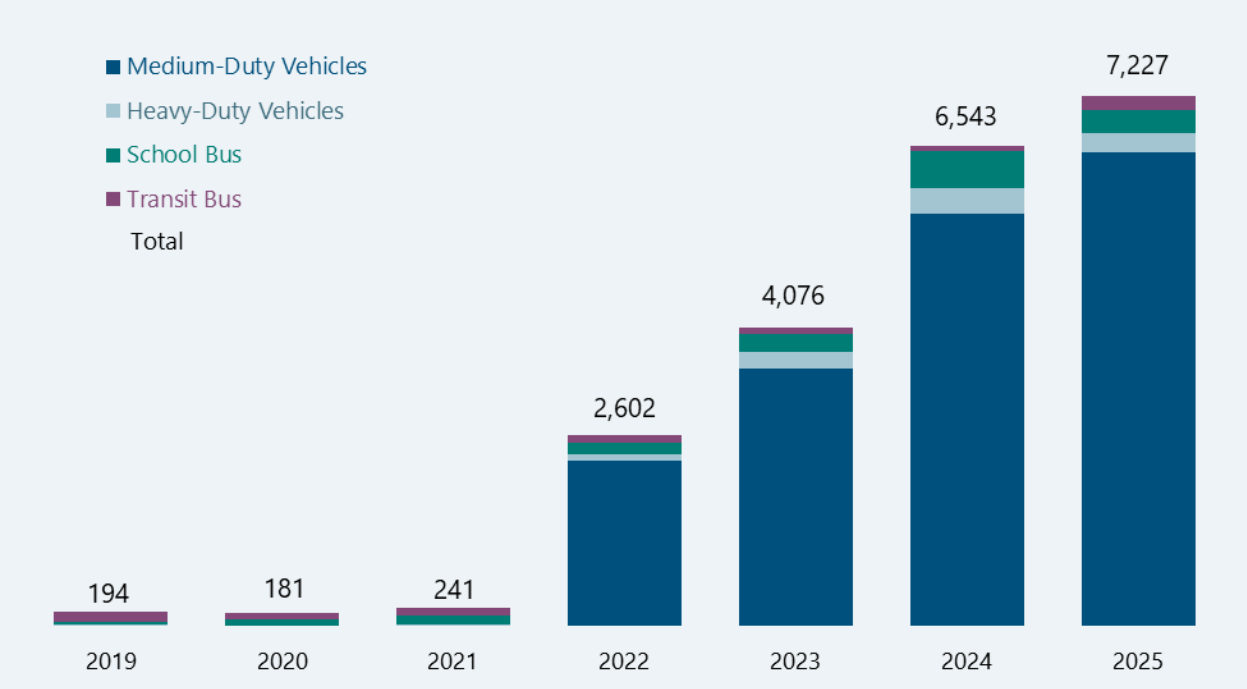
Figure 10. Annual Sales of MDHD Fleet EVs in California (Class 2b–8)



Source: Atlas Public Policy

Figure 11 shows a similar view as Figure 10 broken down by market sector. Figure 11 includes only four market sectors to align with the four market sectors in the Statewide Chapter. In 2025, medium-duty vehicles represented the largest share of the on-road market sectors, followed by school buses, heavy-duty vehicles, and then transit buses, showing similar proportions as in 2024. Since 2022, the medium-duty vehicle market sector has added 20,448 BEVs to California's roads and has experienced consistent annual growth, including a 10.4 percentage point increase from 2024 to 2025. School buses and transit buses had the highest new share of EV sales in 2025 of any market sector, with 58% and 39% of overall MDHD sales, respectively.

Figure 11. Annual Sales of MDHD Fleet EVs in California by Market Sector (Class 2b–8)

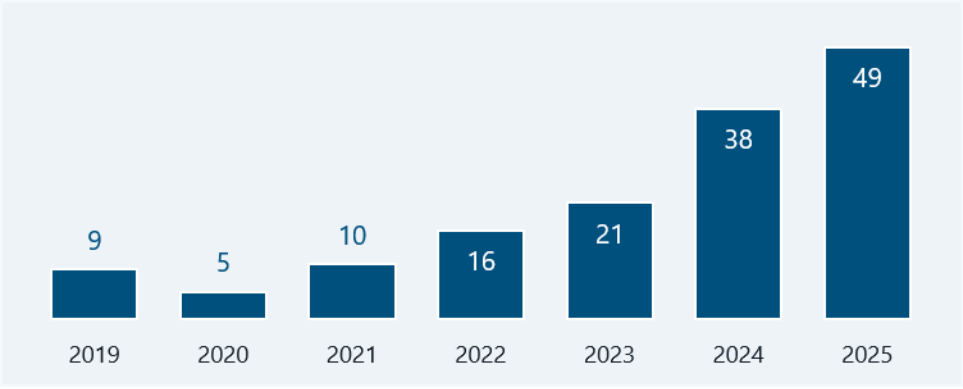


Source: Atlas Public Policy

2.3.2. MDHD Models

Figure 12 depicts the number of distinct models in California's 2025 MDHD market. In 2025, California had 49 unique models of MDHD BEVs, which is 11 more than in 2024. Within the market sectors in 2025, the number of unique models of vehicles by sector was 16 for heavy-duty vehicles, 23 for medium-duty vehicles, five for school buses, and five for transit buses.

Figure 12. 2019–2025 Unique MDHD BEV Models for Sale in California (Class 2b–8)



Source: Atlas Public Policy

Table 10 exhibits Class 2b to 8 fleet MDHDs sold in California in 2025 by make/model. The data presented below excludes registrations of vehicles for personal use. Table 10 maintains the trend shown in Figure 12,

for 2025, in which the medium-duty vehicle market sector accounts for the largest number of registered commercial MDHD Class 2b to 8 vehicles in California, followed by school buses, heavy-duty vehicles, and then transit buses.

Table 10. Fleet Class 2b through Class 8 MDHD EVs Sales in 2025 in California

Make	Model	Class	Market Sector	2025 Sales
Autocar	XSPOTTER	Class 8	Heavy-Duty Vehicle	2
Battle Motors	LNT	Class 8	Heavy-Duty Vehicle	3
	Raider	Class 8	Heavy-Duty Vehicle	2
	Striker	Class 7/8	Heavy-Duty Vehicle	7
Bluebird	All American/All Canadian	Class 6	School Bus	195
	Vision	Class 8	School Bus	34
Brightdrop (GM)	ZEVO 600	Class 2b/3	Medium-Duty Vehicle	763
	ZEVO 400	Class 2b/3	Medium-Duty Vehicle	237
BYD	6F/6R	Class 6	Medium-Duty Vehicle	1
	8TT	Class 8	Heavy-Duty Vehicle	13
	Electric Bus	Class 8	Transit Bus	26
	School Bus	Class 8	School Bus	3
Cenntro	Logistar 400	Class 4	Medium-Duty Vehicle	1
Chevrolet	Silverado EV	Class 2b/3	Medium-Duty Vehicle	967
Ford	E-Transit	Class 2b	Medium-Duty Vehicle	667
	F-150 Lightning (Ext. Range)	Class 2b	Medium-Duty Vehicle	2,676
Freightliner	B2 106	Class 7/8	School Bus	18
	ECascadia 116	Class 8	Heavy-Duty Vehicle	75
	EM2 106	Class 6/7	Medium-Duty Vehicle	16
	MT50E	Class 5/6	Medium-Duty Vehicle	12
Gillig	Low Floor Bus	Class 6	Transit Bus	95
IC Corporation	CE School Bus	Class 7/8	School Bus	91
International	EMV	Class 7/8	Heavy-Duty Vehicle	19
Isuzu	NRR	Class 5	Medium-Duty Vehicle	131
Karsan	Jest	Class 3	Transit Bus	1
Kenworth	K270E	Class 6	Medium-Duty Vehicle	6
	K370E	Class 7	Heavy-Duty Vehicle	3
	T680E	Class 8	Heavy-Duty Vehicle	8
Mack	LR	Class 8	Heavy-Duty Vehicle	1
	MD6	Class 6	Medium-Duty Vehicle	6
Mercedes-Benz	eSprinter	Class 2b	Medium-Duty Vehicle	195
Mullen	Three	Class 3	Medium-Duty Vehicle	10
New Flyer	Xcelsior	Class 8	Transit Bus	69
Novabus	LFS	Class 8	Transit Bus	2
Peterbilt	520EV	Class 8	Heavy-Duty Vehicle	19
	220EV	Class 6/7	Heavy-Duty Vehicle	9
	579EV	Class 8	Heavy-Duty Vehicle	4

Make	Model	Class	Market Sector	2025 Sales
Ram	Promaster EV	Class 2b	Medium-Duty Vehicle	36
Rivian	EDV 500	Class 2b	Medium-Duty Vehicle	14
	EDV 700	Class 2b	Medium-Duty Vehicle	613
	RCV 500	Class 2b	Medium-Duty Vehicle	14
Rizon	FECXKS	Class 5	Medium-Duty Vehicle	1
	FEC7KS	Class 4	Medium-Duty Vehicle	2
	FEC9KS	Class 5	Medium-Duty Vehicle	38
SEA	5e	Class 5	Medium-Duty Vehicle	9
Tesla	Semi	Class 8	Heavy-Duty Vehicle	11
Tico	Pro-spotter	Class 8	Heavy-Duty Vehicle	26
Volvo	VNR	Class 7/8	Heavy-Duty Vehicle	40
Workhorse	W56	Class 6	Medium-Duty Vehicle	37
Total Class 2b through Class 8 MDHD EVs				7,227

Source: Atlas Public Policy

2.3.3. Charging Infrastructure Deployment

The CEC estimates that California has 19,895 active and under-development MDHD charging ports, of which 17,187 charging ports are MDHD private sites and 2,708 are public.[14] For comparison, the MDHD charging stations tracked in this evaluation total 5,489 activated ports in the programs to date with roughly 6,400 additional ports in the pipeline. Assuming this is the same pool of charging ports, these numbers imply approximately 60% of California's MDHD charging ports are tracked in this evaluation.

2.4. Policy and Legislative Landscape

The 12 Utility programs are a result of a broad suite of policies designed to increase EV adoption. This section describes key policies and utility filings across the United States directed at make-ready transportation electrification infrastructure. Previous years' evaluation reports describe the policy landscape prior to 2025.[15]

2.4.1. National-Level Policies and Programs

The federal government took several actions in 2025 that impacted the EV vehicle and charging market. These actions included rescinding the 2009 Greenhouse Gas Endangerment Finding, effective April 20, 2026, and proposing to roll back the fuel economy standards overseen by the National Highway Traffic Administration. The government also paused or suspended implementation of many of the incentive

[14] California Energy Commission. MDHD ZEV Station Development in California. Data last updated September 12, 2025. Retrieved March 22, 2026 from experience.arcgis.com/experience/f951c1433f804daea7f4c33c271aa935/

[15] Cadmus, Energetics, et al. October 2025. *Standard Review Projects and AB 1082/1083 Pilots: Evaluation Year 2024 (Year 4) Third-Party Evaluation Report.* www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/sb-350-te/srp-ab10821083-2024-evaluation-report092025.pdf

programs for EVs under the Bipartisan Infrastructure Law (BIL) of 2021 and the Inflation Reduction Act (IRA) of 2022.

In February 2025, the Federal Highway Administration (FHWA) rescinded existing National Electric Vehicle Infrastructure (NEVI) guidance and froze new funding while reviewing the program to align with the administration's priorities. This sparked a lawsuit by 16 states and the District of Columbia, after which a federal court ordered the release of funds in June 2025. By August, the FHWA issued interim NEVI guidance, signaling the release of the remaining funds to states. To date, the State of California has received nearly $302 million of its awarded $384 million in NEVI funding and $441.2 million (24.8% of the total awards of $1.779 billion for all three rounds across the United States) in Charging and Fueling Infrastructure (CFI) funding (Round 1, Round 1B, and Round 2), targeting a mix of light-duty and MDHD zero-emission refueling infrastructure.

2.4.2. State Policy

The State of California made several changes to its programs and investment related to EV charging and vehicle procurement. One of the more significant changes was to the Advanced Clean Fleets (ACF) regulation. On January 13, 2025, the California Air Resources Board (CARB) withdrew its request for a waiver and authorization for the ACF Regulation under the U.S. Environmental Protection Agency (EPA). The ACF regulation is still in effect for vehicles owned by the state and local governments.

The Advanced Clean Cars II and Advanced Clean Trucks (ACT) regulations also evolved in 2025. The federal government created resolutions seeking to overturn California's waivers for its ACT, Advanced Clean Cars II, and Heavy-Duty Engine and Vehicle Omnibus rules. In response, Governor Gavin Newsom signed an executive order directing state agencies to explore additional pathways to accelerate the deployment of ZEVs across all weight classes.

The California Clean Fuel Reward (CCFR) program, a program which targets MDHD vehicles, took effect on June 26, 2026.[16] The CCFR is a new rebate program with approximately $1 billion in funding from the Low Carbon Fuel Standard (LCFS) program for 2026 to 2030, offered through authorized retailers to both public and private fleets statewide. Incentives range from $7,500 to $120,000 and can be used to offset the cost of purchasing new electric MDHD commercial vehicles, such as drayage trucks, electric semi-trucks, box trucks, delivery vans, and other fleet vehicles. Importantly, CCFR adds to California's existing clean transportation incentive efforts, including the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project, known as HVIP.

Table 11 provides an historical overview of important and significant legislation, policies, and programs in California relevant to transportation electrification through December 31, 2025.

[16] See California Clean Fuel Reward Program website at cleanfuelreward.com/site/home

Table 11. History of Transportation Electrification in California through 2025

History of Transportation Electrification by Year	
Key:	
CA Executive Order, CA Legislative Action (SB and AB), CARB Regulation and Program, CEC Program, and Other CPUC Order Instituting Rulemaking (OIR), Decision, or Resolution	
Pre-2015	(2012) EO B-16-12: 1 million ZEVs by 2025 (2006) AB 32: Global Warming Solutions Act (2008) SB 375: Sustainable Communities and Climate Protection Act (2009) SB 626: Evaluate policies to develop charging infrastructure (2009) CARB approved Low Carbon Fuel Standard (LCFS) (2009) CARB began Hybrid and Zero Emission Truck and Bus Voucher Incentive Project (HVIP) (2010) CARB began Clean Vehicle Rebate Project (CVRP) (2011) CARB began implementing LCFS (2012) CARB adopted Advanced Clean Cars I for model years 2015–2025 (2009) CPUC OIR R.09-08-009 (2011) CPUC D.11-07-029 addressed a range of EV policy issues (2013) CPUC D.13-06-014 extended the treatment of EV charging costs (2013) CPUC OIR R.13-11-007 (2014) CPUC D.14-12-079 adopted rules to expand EV infrastructure (2014) CPUC D.14-12-083 directed the investor-owned utilities (IOUs) to receive credits for electricity and natural gas sold as a fuel (2012) $102.5 million NRG settlement to deploy EV charging infrastructure
2015	SB 350: Clean Energy and Pollution Reduction Act of 2015, enacted Public Utilities Code Section 740.12.1 requiring the CPUC, CEC, and CARB to support the acceleration of widespread transportation electrification CARB approves readoption of LCFS
2016	CARB began implementing readoption of LCFS CPUC D.16-01-023 authorized $22 million for SCE Charge Ready Pilot CPUC D.16-01-045 authorized $45 million for SDG&E Power Your Drive Pilot CPUC D.16-12-065 authorized $130 million for PG&E EV Charge Network pilot
2017	AB 1082: EV Charging Infrastructure: Schools and Educational Institutions AB 1083: EV Charging Infrastructure: State Parks and Beaches CEC Electric Vehicle Infrastructure Project (CALeVIP 1.0) Launched Volkswagen settlement required Electrify America to invest $800 million in California
2018	EO B-48-18: 5 million ZEVs by 2030, 250,000 chargers by 2025 SB 1014: Clean Miles Standard and Incentive Program: ZEVs SB 1000: EV Charging Infrastructure AB 2127: EV Charging Infrastructure: assessment CARB approved amendments to LCFS CPUC D.18-12-006 authorized SCE to spend an additional $22 million for its Charge Ready Light Duty EV Charging Infrastructure program CPUC D.18-01-024 approved the first transportation electrification applications under SB 350 CPUC D.18-05-040 approved $738 million for Utilities' Standard Review Projects (SRP) CPUC D.18-09-034 authorized transportation electrification funding for Bear Valley, Liberty, and PacifiCorp
2019	SB 676: EV-Grid Integration CPUC D.19-08-026 approved $107 million for SDG&E MDHD and vehicle-to-grid (V2G) school bus pilot CPUC D.19-09-006 authorized $4 million for PG&E low- and moderate-income (LMI) customers CPUC D.19-10-055 authorized PG&E subscription-based EV rate CPUC D.19-11-017 approved pilots for EV charging at schools, parks, and beaches

History of Transportation Electrification by Year	
2020	EO N-79-20: 100% Light-duty ZEV sales by 2035; 100% MDHD ZEV sales by 2045 AB 841: Transportation Electrification and School Energy Efficiency Stimulus Program CARB approved ACT, ZEV sales requirements CPUC D.20-08-045 authorized $436 million for SCE on Charge Ready program CPUC D.20-09-025 clarified that EVSPs for MDHD are not public utilities CPUC D.20-12-023 established SDG&E's rate for separately metered EV CPUC D.20-12-027 directed utilities to spend LCFS credits on equity programs CPUC D.20-12-029 authorized implementation of SB 676
2021	CARB adopted Clean Miles Standard for Transportation Network Companies CEC Funded CALeVIP 2.0 Launched CPUC D.21-04-014 approved $43.5 million for SDG&E on a pilot extension CPUC D.21-07-028 established near-term priorities for utility investment CPUC D.21-11-017 authorized PG&E to offer an optional day-ahead rate CPUC D.21-12-033 extended common treatment policy for PEVs CPUC Resolution E-5175 clarified EVSE communications protocols CPUC Resolutions E-5167 and E-5168 established new EV Infrastructure rules
2022	AB 2061: Requires the CEC to develop uptime recordkeeping and reporting standards for EV chargers and charging stations CARB adopts Advanced Clean Cars II for model years 2026–2035 CPUC OIR R.22-07-005 sought advanced widespread demand flexibility through electric rates CPUC D.22-08-024 authorized Plug-In EV Submetering Protocol CPUC D.22-11-040 adopted a long-term transportation electrification policy framework CPUC D.22-12-054 authorized $52.2 million for PG&E's EV Charge 2 program CPUC Resolution E-5192 approved $11.7 million for PG&E's vehicle-grid integration (VGI) pilots CPUC Resolution E-5227 approved SCE's low port rebate proposal CPUC Resolution E-5236 approved SCE programs from LCFS Holdback credits CPUC Resolution E-5247 established an energization timeline under EV Infrastructure Rules 29 and 45
2023	SB 123: Harmonized requirements between EVSE requirements and the NEVI Program SB 410: CPUC to establish reasonable energization time periods AB 50: CPUC to establish criteria for customers to receive timely energization CARB approved ACF CARB closed new enrollments to the CVRP CPUC OIR R.23-12-008 established venue for transportation electrification policy and closed 18-12-006 CPUC Resolution E-5257 approved modifications to PG&E's EV Fleet program and SCE's Charge Ready Transport program per se reasonableness metrics
2024	SB 59: Authorized the CEC to require any weight class BEV to be bidirectional capable AB 2697: Required the CEC to apply network roaming standards to only major EV charging network operators AB 2037: Authorized counties to test reliability of EVSE and provided leeway to issue fines for broken EVSE EPA granted waiver for CARB's Advanced Clean Cars II CEC approved four-year, $1.4 billion for the Clean Transportation Program CPUC D.24-09-020 established target energization timelines and procedures to report delays
2025	CARB withdrew its EPA waiver request for ACF Federal Government rescinded waiver for CARB's Advanced Clean Cars II CEC released $120 million in funding through the Clean Transportation Program for port ZEV Infrastructure, ZEV Blueprint Implementation, Depot Infrastructure CEC released $93 million in EnergIIZE funding for Fast Track, Transit and Drayage, and MegaWatt Chargers CEC released $55 million for CALeVIP 2.0 and $56 million for Communities in Charge South Coast AQMD released RFP for $500 million INVEST CLEAN charging program in Southern California

2.4.3. Additional Funding Paths

Since the initiation of the Utility programs, the State of California has implemented a number of new funding paths for TTM, BTM and EVSE infrastructure. The most notable overlapping programs are the Utilities' EV Infrastructure Rules (Rule 29 for SCE and PG&E and Rule 45 for SDG&E) and the CEC's EnergIIZE program. Table 12 compares these programs across a number of dimensions.

Table 12. Comparison of SRPs, EV Infrastructure Rules, and EnergIIZE Program

	Standard Review Projects	EV Infrastructure Rules [a]	CEC EnergIIZE Program
Sponsor	SCE, PG&E, SDG&E	All Utilities in California	CEC
Authorized Budget	$687M	Per Resolutions E-5167 and E-5168, costs are recovered through general rate cases and recorded in a Memorandum Account.[b]	$544M (Multi-round)
Duration	2019–2026	2022 onward	2022–3/31/2026
Eligible Expense	TTM, BTM, EVSE	TTM	BTM, EVSE, Hydrogen refueling
Eligible Participants	Commercial on-road, off-road fleets with Class 2b to Class 8 vehicles	Commercial on-road, off-road fleets; multifamily buildings	Commercial on-road, off-road fleets with Class 2b to Class 8 vehicles
DAC Requirements	25-40% of spending in DACs (SCE: 40%, SDG&E: 30%, PG&E: 25%)	None	60% of spending in DACs
Stackable Funding	Cannot be stacked with Rule 29/45	Cannot be stacked with SRPs	Stackable with other federal and Utility programs [c]

[a] Including Rule 29 and Rule 45

[b] Rule 45 is currently out of budget due to the funding cap established in the General Rate Case, as covered in the still-pending AL 4705-E.

[c] The Evaluation Team reviewed data from the CEC EnergIIZE program and found that 59% of sites in EnergIIZE were also enrolled in SRP.

2.5. Barriers to MDHD Electrification

This section explores why the MDHD market has been slower to develop than was anticipated in the original CPUC decisions in 2018 and 2019.[17] Public charging programs are not discussed in this section.

[17] In its original decisions in 2018 (Decision 18-05-040) and 2019 (Decision 19-08-026), the CPUC required 870 sites for SCE Charge Ready Transport, 700 sites for PG&E EV Fleet, and 300 sites for SDG&E PYDFF. The CPUC also required 8,490 EVs for SCE Charge Ready Transport, 6,500 EVs for PG&E EV Fleet, and 3,000 EVs for SDG&E PYDFF. Those site goals have been lowered to 500 for SCE Charge Ready Transport and 375 for PG&E EV Fleet (Resolution E-5257, Resolution E-5347).

2.5.1. Progress Toward Site and Vehicle Goals

Figure 13 shows progress toward the combined per se reasonableness site (left) and vehicle (right) targets. Solid lines depict actual historical data. Dashed lines show projections made by the Evaluation Team.[18] The methodology behind these curves is described in *Appendix B*.

Figure 13. Utility Program Progress Toward Site and Vehicle Targets

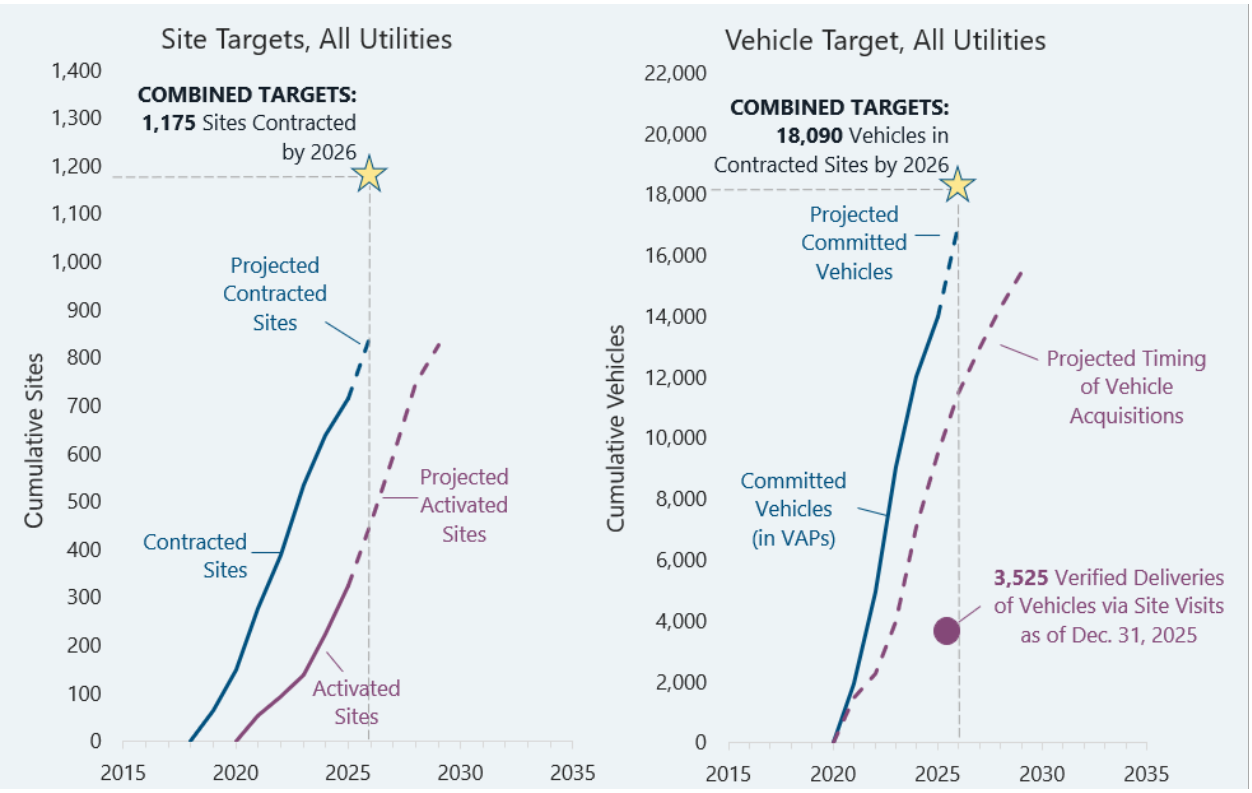


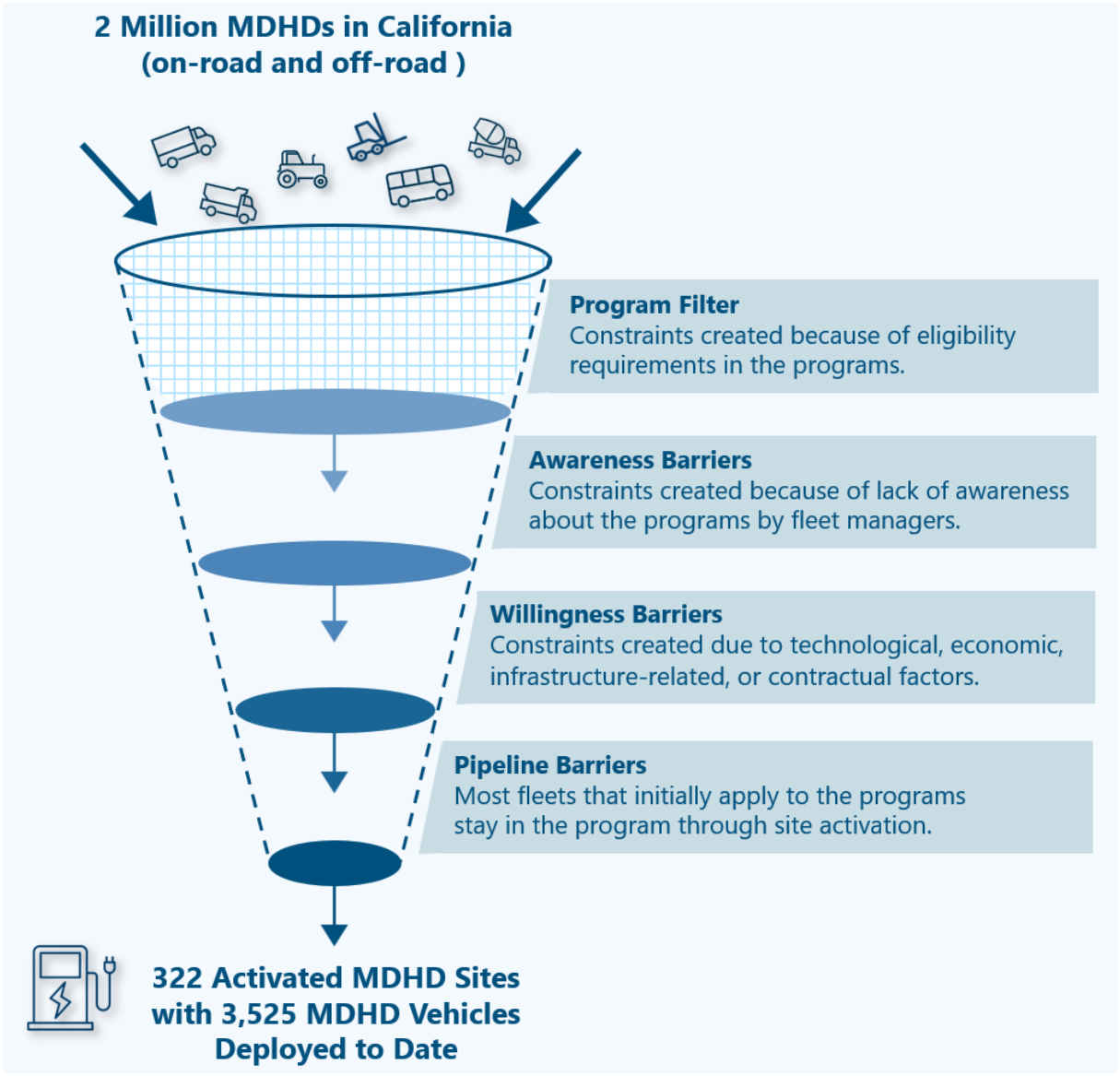
Figure 13 provides several insights: First, the programs are on track overall to meet the combined vehicle targets but not the combined site targets. Figure 13 also highlights the long lead time between a fleet signing a contract with the Utility and acquiring the last of its planned vehicles. This long lead time is driven by an activation timeline of at least three years plus a 5-year or 10-year VAP, depending on the Utility. In other words, for MDHD programs that end in 2026, the last vehicles will not be delivered until the late 2030s.

[18] The Evaluation Team projects contracted sites using an average of the number of signed contracts for the previous three years (2022–2024) and projects activated sites using the contracted site trend line and assuming a 10% drop-out rate between contracted sites and activated sites and a three-year lag between contract signing and activation. VAP projections use an average VAP count for the previous three years (2022–2024). Projected vehicle deliveries use estimates in the VAPs filed by program participants, accounting for five-year VAPs of PG&E EV Fleet and 10-year VAPs for the other two programs.

2.5.2. Funnel Framework

The Evaluation Team developed a conceptual framework to illustrate barriers that reduce program participation (Figure 14). At the top of the funnel are all MDHD Class 2b–8 vehicles in California—approximately 2.2 million on-road and off-road vehicles. At the bottom are the 322 activated sites that support 3,525 MDHD vehicles deployed to date.[19] Between these end points are a set of barriers that lower the program participation rate, discussed below. The diagram is conceptual in nature. In reality, the stages in the filter may not follow a linear, step-by-step process.

Figure 14. Conceptual Diagram of Barriers to MDHD Program Participation



[19] This is likely an undercount because some of the vehicles were verified by the Evaluation Team in site visits in previous years, and fleets have likely increased their vehicle counts since the site visit.

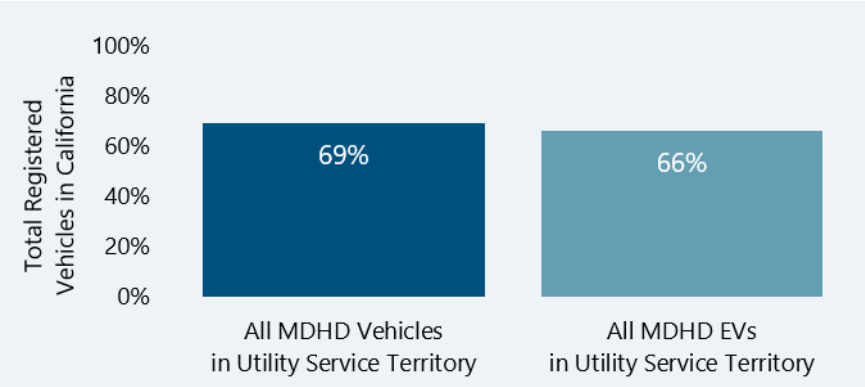
Program Filter

The program filter barriers are created by eligibility requirements of the Utility programs. Below we discuss several of these barriers and quantify them when feasible.

Service Territory

To enroll in the MDHD programs, fleets must be located in the service territory of SCE, PG&E, or SDG&E. These three territories cover roughly 78% of the land area in California, serve 79% of California's population, and encompass 69% of the registered on-road MDHD vehicles.[20] This service territory constraint reduces the number of eligible participants from the full pool of California MDHDs. Figure 15 shows the fraction of Class 2b to Class 8 vehicles that are included in the Utility territories.

Figure 15. Share of Total MDHD Vehicles Inside Utility Service Territories



Utility Service Territories include SCE, PG&E, and SDG&E

2+ Vehicle Requirement

The Utility MDHD programs require fleets to commit to acquiring at least two EVs; however, for some small MDHD fleets, especially those of small businesses that own a single vehicle, acquiring two EVs may not be feasible. We estimate that 88% of the state's MDHD vehicles belong to fleets with two or more vehicles.[21]

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[20] The Evaluation Team estimated the MDHD vehicle percentage using data in the CARB, EMFAC tool. Vehicle types included are Class 2b trucks and Class 3, 4, 5, 6, 7, and 8 vehicles and buses. Mobile homes and other Class 2 vehicles were excluded. The summation of the zip code specific vehicle population data in EMFAC does not equal the statewide vehicle population totals from EMFAC. The Evaluation Team uses the summation of the zip code specific vehicle population data.

[21] The Team derived this estimate from the EMFAC Database using 2023 vehicle populations. arb.ca.gov/emfac/fleet-db/9b44758fdcc351a75c8183fb51d804ffcba04f60

Approved Product List

The Utility programs require fleets to choose from a set of vendors on the Utilities' APLs. The vendors on these lists account for *less than half* of vendors offering EVSE in the United States.[22] Through interviews with staff from all three Utilities for prior evaluation reports, the Evaluation Team learned that the APL creates a barrier to participation for some fleets who have a preferred EVSE vendor that is not on the APL. In addition, Utility staff suggest that customer experiences with EVSE vendors, particularly related to customer service and post-installation support, have been subject to peer-to-peer discussions between customers sharing lessons learned and reputational assessments. In some cases, shared negative experiences or perceptions can lead to decreased customer willingness to participate, highlighting the importance of consistent service quality across vendors, especially those recently added to the APLs.

Cost Threshold

The Utilities use a maximum cost per site and cost per vehicle threshold in alignment with their site and vehicle goals to screen customer applications. Cost thresholds are based on the available funding remaining in the program budget divided by the number of sites or number of vehicles. The Utilities encourage sites with cost estimates that exceed these thresholds to enroll in Rule 29 or Rule 45.[23] According to interviews with Utility staff, these thresholds limit the number of potential program applicants, although staff did not provide estimates for the magnitude of this barrier.

Awareness Barrier

Even if fleets are eligible for a Utility program, they need to be aware of the program to participate in it. Awareness is a well-recognized constraint to EV adoption and is defined as having a low existing knowledge base about the programs or low ability to access or acquire knowledge about the programs. As reported in the EY2024 Evaluation Report, Utilities have dedicated staff for identifying and outreaching to eligible fleets. However, none of the Utilities track the percentage of fleets in its territory who are aware of the program.

Willingness Barrier

For a variety of reasons discussed below, only a subset of fleets that are eligible for and aware of the MDHD programs will participate. Factors that impede willingness to participate are centered on the technology, economic concerns, and infrastructure issues. This section presents high-level insights drawn from surveyed PG&E, SDG&E, and SCE program participants and from interviews conducted with 10 fleet managers who dropped out of the program and could therefore describe the factors that affected their willingness to participate. We present more detailed information on the results of these surveys and interviews in the respective program findings sections.

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[22] The Team derived this estimate by comparing EPRI's APL list to the SB 350 APL. www.epri.com/vpl

[23] Customers were primarily referred to Rule 45 throughout 2025. After the sunset of Rule 45, Utilities have been referring customers to other electric rules such as Rule 15 and Rule 16.

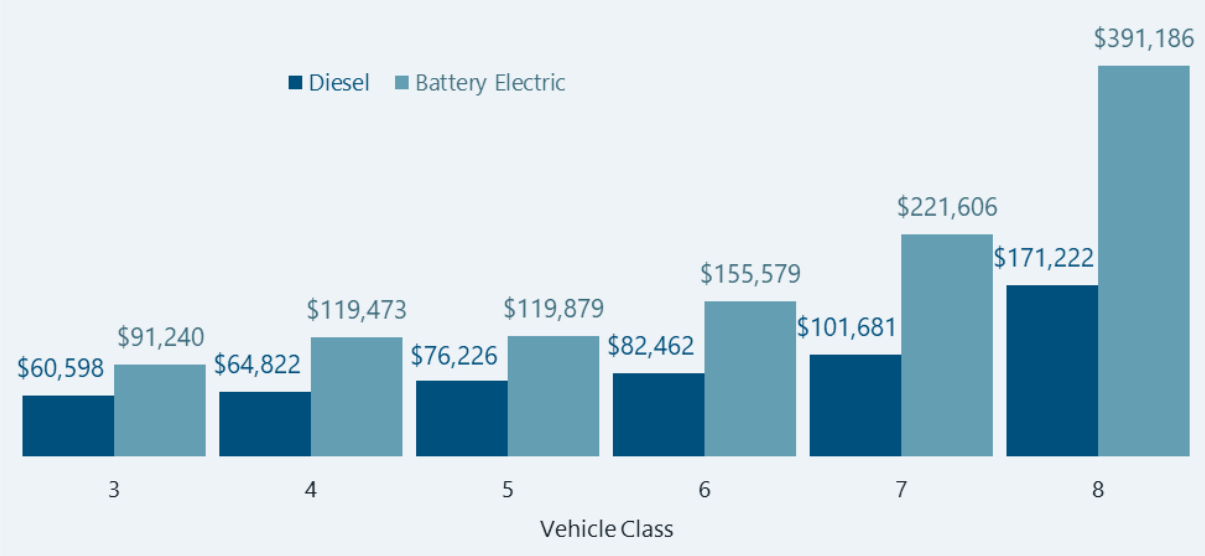
Economic Factors

High up-front cost of EVs and, EVSE, and charging infrastructure. The cost of EVs relative to the cost of alternatives across all vehicle classes is a key barrier to fleet electrification. This difference in cost is reflected in the cost premium for EVs compared with traditionally fueled vehicles, as well as the associated costs for charging infrastructure. Figure 16 shows the cost differential between generic, electric, and diesel Class 3 to 8 vehicles as estimated by the National Laboratory of the Rockies (NLR).[24] The premium for EVs increases (as a percentage) as the vehicle class rises.[25]

Cost was noted as a barrier in multiple interviews held by the Evaluation Team. Staff at two of the three Utilities stated in phone interviews that high up-front costs associated with fleet electrification relative to internal combustion engine (ICE) alternatives prevented greater program participation.

The up-front cost barrier is also reflected in fleet manager surveys. Prior to program participation, 65% of survey respondents[26] indicated that EV costs were a key willingness barrier, and 62% of respondents indicated the same for EV charging infrastructure costs. After participating in the program, this dropped to 46% of respondents indicating that EV costs were a key barrier and those indicating that EV charging infrastructure costs were a barrier dropped to 31% of respondents. This indicates that while the program did lower the barrier posed by the high up-front cost of EVs and EV charging infrastructure, the cost barrier remained a key consideration for some respondents.

Figure 16. Comparison of 2024 Up-Front Modeled Cost for Diesel vs. BEVs



[24] Figure 16 uses the 2023, constant scenario from NLR's (formerly known as the National Renewable Energy Laboratory) NREL's *2024 Transportation Annual Technology Baseline* (ATB). atb.nrel.gov/transportation/2024/technologies. The 2025 Transportation ATB with updated cost values has not been released. The most recent citable dataset at the time of writing is still the 2024 ATB.

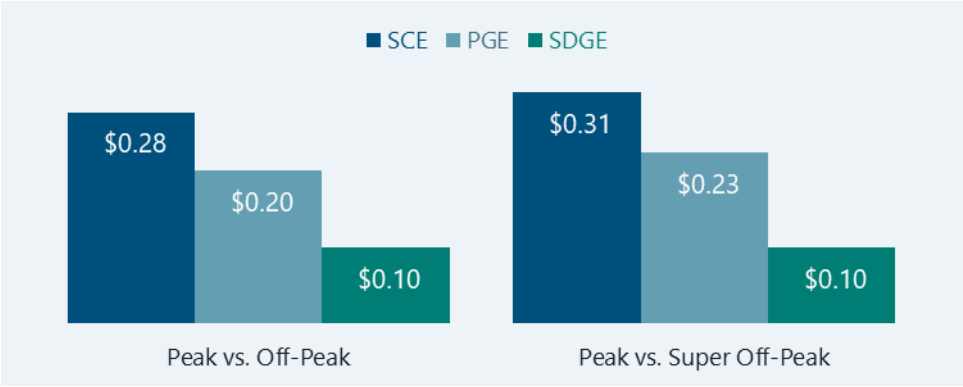
[25] The Evaluation Team does not collect vehicle costs as part of this evaluation.

[26] The total number of fleet manager survey respondents is 26; not all respondents answered every question.

Uncertainty around regulations and broader market conditions. Utility staff indicated that changes in federal policy and broader regulatory uncertainty in 2025 created hesitation among customers, with some fleets becoming less responsive or delaying engagement unless they were required to move forward. Pertaining to ACF regulations, Utility staff interviewees evoked mixed impacts on the ACF regulation repeal. While some site cancellations were attributed to the rollback of the ACF, the overall program impact was mixed, as many public sector fleets, including municipalities, schools, and transit agencies, remain subject to other regulatory mandates and continued to participate. More broadly, Utility staff emphasized that an evolving and uncertain regulatory environment is a primary driver in fleet decision-making toward electrification. Changes to federal policies, including broader EPA deregulation efforts, created confusion and reduced momentum, particularly among commercial fleets. Thus, maintaining sentiments from last year's Evaluation Report, "a lot of industries are in the wait-and-see period," due to uncertainty around regulatory enforcement. Two Utility representatives noted that regulatory drivers remain the primary factor influencing fleet electrification decisions, followed by cost and vehicle availability. Uncertainty in broader market conditions, including loss of funding, delays in incentive payments, original equipment manufacturer (OEM) exits, and charger or vehicle discontinuations, have further increased perceived risk.

Uncertainty around access to TOU rates. While TOU rates help lower the cost of electricity for fleets with the flexibility to use them, last year's Evaluation report highlights how some fleets are unable to take advantage of off-peak TOU rates due to long charge times, inflexible loads, or both. As presented in Figure 17, the savings available to fleets by using the super off-peak versus the peak pricing can be as high as $0.31/kWh in SCE territory. These TOU rates are offered at different maximum monthly kilowatt demand levels and include subscription costs and overconsumption fees not included in these prices.

Figure 17. Average Cost Difference in TOU Rates



For SCE, Super Off-Peak is available only in the winter, when peak demand rates are lower. Weekend peak rates are not represented here. These averages include winter and summer values. SDG&E rates do not include EECC, WF-NBC, Schedule DWR-BC. The $/kWh values are averages of all TOU rates offered by each Utility

Survey results indicated that 81% of fleet managers are aware of utility TOU rates, but only 23% of respondents said they were not aware of the total costs of fleet charging for their company.

Technology Factors

Uncertainty around the ability of EV and EVSE technology to meet the needs of fleet owners. Despite their efforts to provide educational resources, Utility staff interviews suggest that current EV and EVSE technologies do not satisfy all fleet use cases and some sectors have been more difficult to electrify. Staff noted challenges related to vehicles that the current EV makes and models available do not always meet the needs of every vehicle type, especially heavy-duty or high mileage applications. 39% of surveyed fleet managers noted they are not satisfied with the current EV options on the market for their sector. Respondents generally attributed this to range limitations for the use case and some cited limited or no longer available (e.g. F-150 Lightning) EV models. In tandem, 19% of fleet managers noted that prior to program participation it was challenging to find the right types of EVs for their needs. 39% of respondents highlighted that their routes were too long for the EVs available. 8% of fleet manager respondents said that after program participation, these concerns were mitigated. This may indicate the continued value of real world and business case examples when addressing willingness barriers.

Uncertainty around the longevity of OEMs and EVSE firms. A Utility interviewee reported that fleet managers felt uncertain about the stability and longevity of EV and EVSE vendors. Utility staff noted instances where OEMs or EVSE firms discontinued product lines, exited the market, or where customers lost vendor support mid-project. These disruptions introduce risk for fleets, particularly given long project timelines and equipment lead times. Staff also highlighted the ongoing challenges in the EV market, including shifting OEM competition and limited availability of certain EV types. As a result, fleets may delay participation or reconsider technology choices due to concerns about long-term support, EV and EVSE reliability, and the ability to maintain operations over the life of the investment.

Vehicle Depot and On-Route Charger Deployment

Land contractual factors. A large fraction of fleets lease the land of their depots, which means a fleet must collaborate with another party to participate in the programs. According to interviews with staff from two Utilities, a fleet owner's inability to install chargers due to renting, instead of owning, was a key willingness constraint. In a 2020 survey of MDHD fleets implemented by CARB, 56% of fleets reported owning (instead of leasing) the facility at which they parked their vehicles.[27] This survey included 1,866 fleets, 7,767 facilities, and 386,286 vehicles above 8,500 lbs. As shown in Figure 18, the CARB survey estimates that 50% of land leases span 10 years or less, creating a challenge for long lead infrastructure and/or fleets needing to make 10-year VAPs.

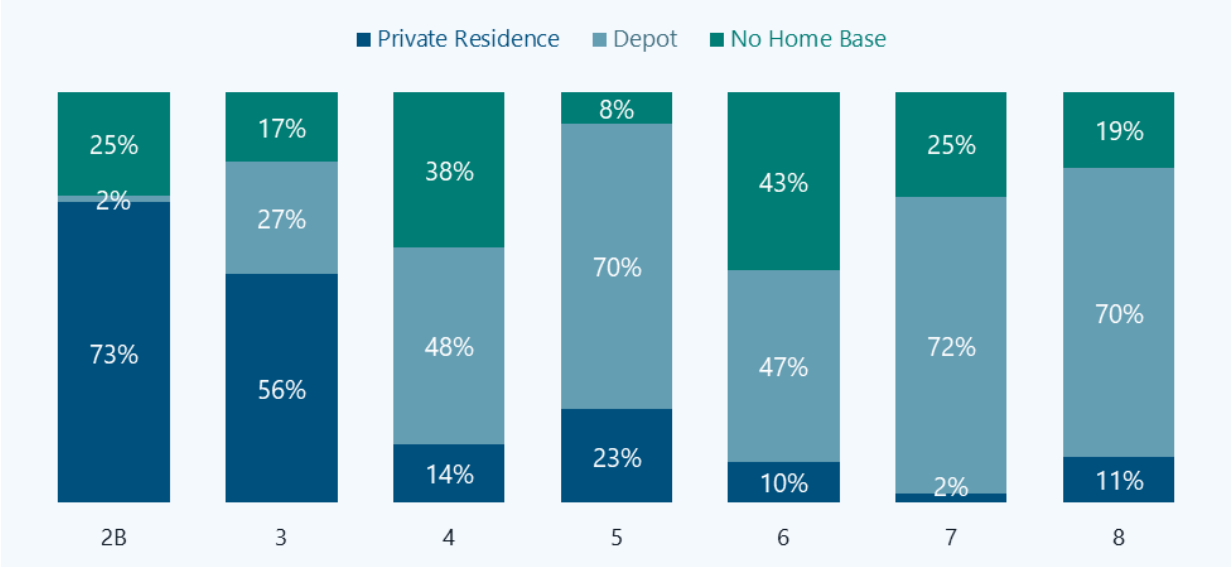
[27] CARB 2022. Large Entity Reporting Statewide Aggregated Data. ww2.arb.ca.gov/sites/default/files/2022-02/Large_Entity_Reporting_Aggregated_Data_ADA.pdf

Figure 18. Length of Fleet Leases in California



Vehicles parked at homes. Vehicles parked at private residences are not eligible for the MDHD programs. As shown in Figure 19, the fraction of vehicles that park at home varies by vehicle class. In total, 45% of California's MDHD vehicles are based at a private residence according to data in the 2021 Vehicle Inventory and Use Survey.[28]

Figure 19. Fraction of Class 2b to Class 8 Vehicles in California, by Home Base Location



Pipeline Barrier

Pipeline barriers are any reason in which sites withdraw from the Utility programs between contract signing and site activation. The average lead time between contract signing and site activation is more than three years across sites, providing opportunities for a fleet to change its electrification strategy. Across the three MDHD programs, a relatively small number of contracted sites, ranging from 8% to 15%, withdraw from the programs.[29]

The Evaluation Team conducted 10 interviews with fleets who had withdrawn from the programs, two from SCE and eight from PG&E. These interviewees included representatives from school districts, a waste

[28] U.S. Department of Transportation, Vehicle Inventory and Use Survey from 2021. www.bts.gov/vius

[29] The lower value is the total contracted withdrawn sites divided by the total contracted sites. The higher value is the total contracted withdrawn sites divided by the total activated sites plus the total contracted withdrawn sites.

management authority, a regional water district, retailers, EV charging infrastructure developer, and a California county. Two key themes emerged as reasons for program withdrawal: higher than expected costs did not fit their budgets and changing regulatory signals. Each is described below.

Customer Project Costs Exceeded Available Budgets

The vast majority of fleets interviewed, including 70% who withdrew from the program, cited the inability to align required site costs they faced with available budgets. Interviewees stated that the up-front costs of customer-side infrastructure are too expensive and vehicles are unaffordable, particularly for heavy-duty vehicles. Three of the fleets that withdrew from the program due to costs did so at or near the end of the planning phase.

Shifting Regulatory Landscape

30% of fleets who withdrew cited shifting regulatory requirements as their reason for withdrawal. These fleets said that initially the ACF regulation was a central driver for their interest in electrifying. When it became apparent that the ACF would no longer be enacted for commercial fleets, the three fleets withdrew from the program.

3. Statewide MDHD Vehicle Findings

Unlike other chapters of this evaluation which examine individual utility programs, this chapter synthesizes statewide findings across all MDHD programs. When appropriate, the Evaluation Team segments findings for four market sectors: medium-duty vehicle, heavy-duty vehicle, school bus, and transit bus.[30] By aggregating programs, this chapter highlights trends across a larger pool of sites and vehicles than individual program chapters and therefore provides more robust and generalizable findings.

3.1. Summary Statistics

Table 13 shows the number of sites for five key program metrics (applications, contracts, activated, operational, and sites visited) for the four market sectors as of the end of 2025. Similar to EY2024, the medium-duty vehicle market sector shows the greatest number of applications (572); however, the school bus market sector has continued to have the largest number of activated sites in the program to date, with 120, compared with 88 for medium-duty vehicle, 65 for heavy-duty vehicle, and 31 for transit bus sectors.

Table 13. PTD Sites by Program Status and Market Sector

Market Sector	Applications [a]	Contracts	Activated	Operational	Sites Visited
Medium-Duty Vehicle	572	298	88	82	78
Heavy-Duty Vehicle	178	96	65	64	63
School Bus	277	217	120	118	107
Transit Bus	84	62	31	28	23

[a] The count of applications excludes sites that have been cancelled or withdrawn.

Table 14 focuses on activated sites across the same four market sectors by highlighting the total number of vehicles and ports for each. Although the school bus market sector leads the programs in total activated sites, the medium-duty vehicle and heavy-duty vehicle market sectors each have more vehicles and ports, with the medium-duty vehicle market sector having nearly double that of the school bus market sector. The transit bus market sector has the fewest activated sites, vehicles, and ports of the four market sectors.

[30] These four market sectors are the only market sectors with enough sites to meet the 15-15 Rule for analysis. The 15-15 Rule protects customer privacy by limiting the reporting of customer metrics and data when an insufficient number of customers exist in a given category. In practice, this means certain metrics cannot be included in public reporting unless there are at least 15 sites and as long as no single site accounts for more than 15% of all energy consumption. More information on the 15-15 Rule can be found in Decision 14-05-016.

Table 14. PTD Activated Sites, Vehicles, Ports by Market Sector

Market Sector	Activated Sites	Vehicles	Ports
Medium-Duty Vehicle	88	3,226	2,205
Heavy-Duty Vehicle	65	1,667	1,213
School Bus	120	1,462	1,149
Transit Bus	31	424	311

The Evaluation Team observes vehicles only once, during site visits. Figure 20 shows the difference between the sites' full VAP and the number of vehicles verified during site visits (which typically occur within the first year after site activation). Because the site visit occurs early in the site's VAP, the Team expects to observe fewer vehicles than in the full site VAP. School bus sites had the largest portion of the vehicles listed in their VAPs delivered at the time of the site visit (53%), while medium-duty vehicle sites had the smallest portion (22%). Heavy-duty vehicle and transit bus fleets each had nearly half (47%) of the vehicles listed in their VAPs delivered at the time of the site visit.

At many site visits, the Evaluation Team observes fewer vehicles than expected per the delivery schedule in the VAP (not shown in Figure 20). In previous evaluation years, the Evaluation Team recommended that Utilities annually track and update customer VAP progress, and in 2025 two Utilities had implemented this recommendation.

Figure 20. Full VAP and Vehicles Observed during Site Visits by Market Sector for PTD Sites

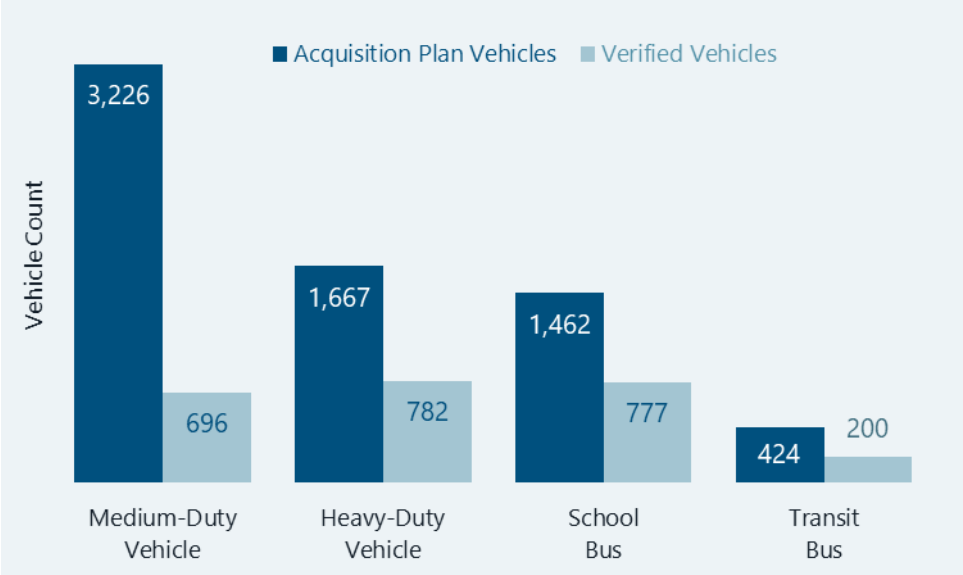
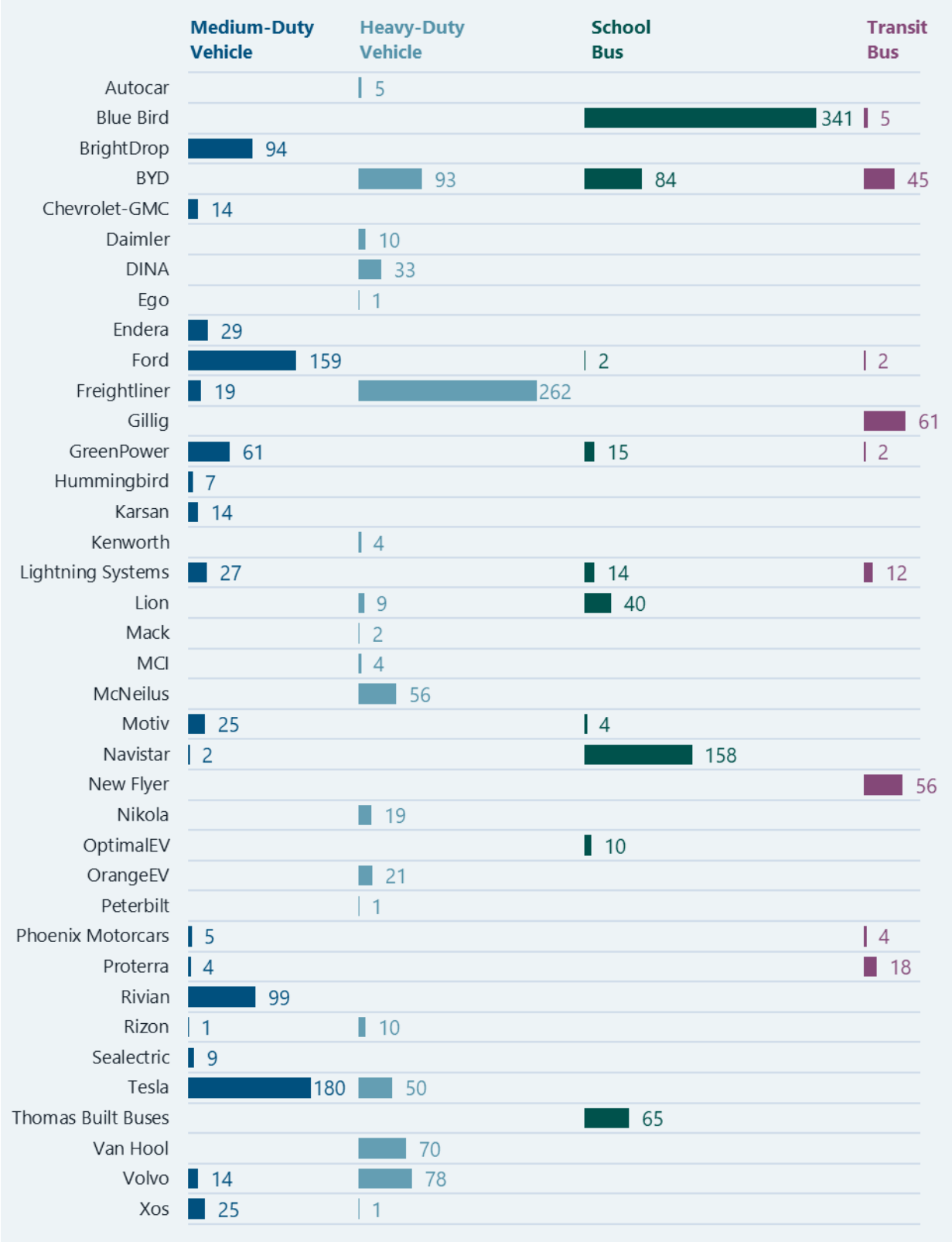


Figure 21 shows vehicle make by market sector for all vehicles observed at activated sites in the program to date. The largest suppliers of vehicles across the medium-duty vehicle, heavy-duty vehicle, school bus, and transit bus market sectors were Tesla, Freightliner, Blue Bird, and New Flyer, respectively. In December of 2025, not all companies listed in Figure 21 were still incorporated.

Figure 21. Vehicle Make by Market Sector for PTD Sites



Highlights

- The medium-duty vehicle market sector has the greatest number of applications (572) and therefore will have the most sites once all sites are activated.
- As of December 2025, the school bus market sector has the largest number of activated sites in the program to date, with 120, compared with 88 for medium-duty vehicles, 65 for heavy-duty vehicles, and 31 for transit buses.
- At the time of the site visits, the Evaluation Team observed only a fraction of the vehicles in the site VAPs.

3.2. Site-Activation Timelines

3.2.1. Analysis of Sites by Activation Year

Table 15 shows the median calendar days for each CPUC program phase aggregated across the same four market sectors (medium-duty vehicle, heavy-duty vehicle, school bus, and transit bus) for sites activated in EY2021 through EY2025. Overall median calendar days have increased steadily with each program evaluation year, with median start-to-finish durations rising from 616 days in EY2021 to 1,014 in EY2025.[31] This trend reflects the growing share of large, complex projects (which inherently take longer than smaller sites to reach activation) coming online in later program years.

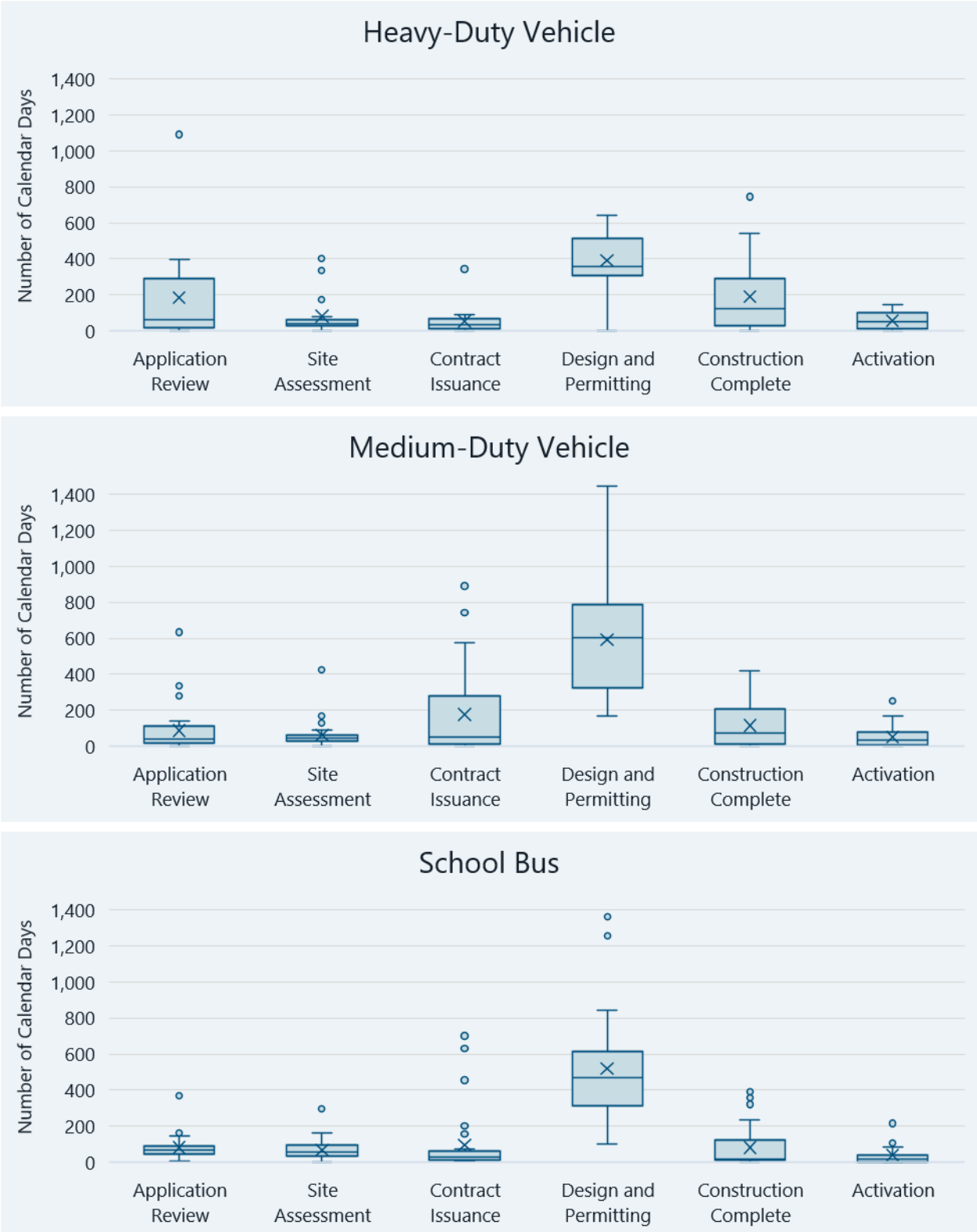
Table 15. Median Calendar Days by Activation Year and Program Phase for PTD Sites in Four Market Sectors

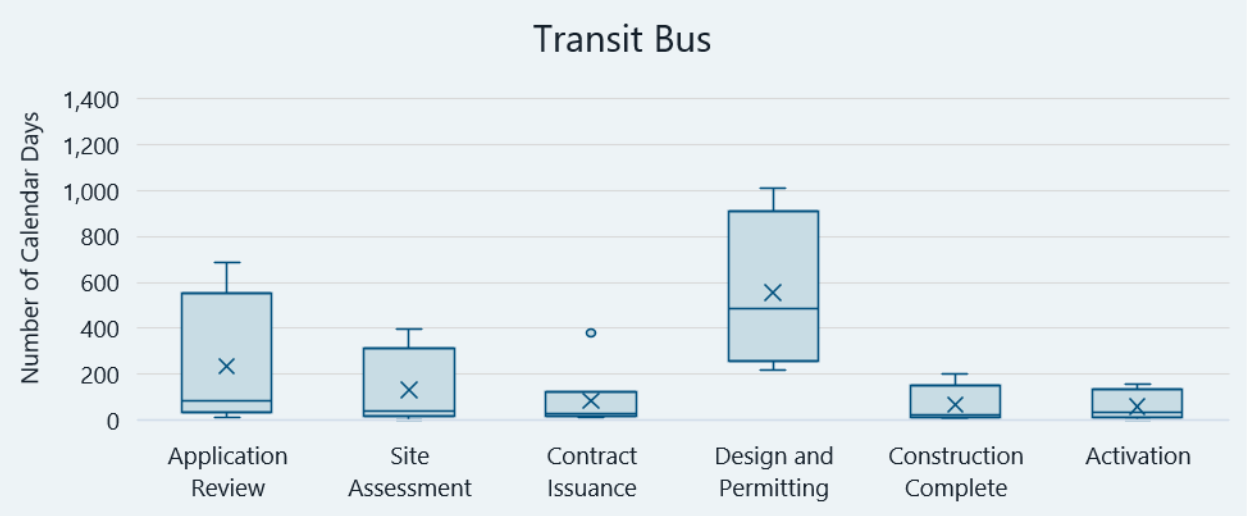
CPUC Program Phase	Median Calendar Days				
	EY2021	EY2022	EY2023	EY2024	EY2025
Application Review	36	32	45	74	65
Site Assessment	35	30	40	38	49
Contract Issuance	30	46	66	37	36
Design and Permitting	224	257	348	476	499
Construction Complete	84	130	106	58	34
Activation	29	17	21	24	23
Start to Finish	616	666	862	983	1,014

Figure 22 expands the analysis of program phase duration for EY2025 activated sites by displaying the average number of calendar days per phase (denoted by X), calendar day median (middle line inside of box), first quartile (bottom of box), third quartile (top of box), minimum (bottom tail), maximum (top tail), and outliers (dots) for each of the four market sectors.

[31] The SCE Charge Ready Transport, PG&E EV Fleet and SDG&E Power Your Drive for Fleets programs are not subject to the energization timeline targets established in CPUC D.24-09-020.

Figure 22. Calendar Days per Phase for EY2025 Sites by Market Sector





3.2.2. Analysis of Sites by Application Year

As an alternative to the *activation year* analysis in *Analysis of Sites by Activation Year*, this section examines sites by application year (i.e., the year a fleet completed an application and entered the program). Segmenting sites by application year allows the Evaluation Team to better account for broader, market-wide changes that systematically impact site development in a given year (e.g., COVID-19). Table 16 presents median calendar days by CPUC program phase grouped by application year across the medium-duty vehicle, heavy-duty vehicle, school bus, and transit bus market sectors.

Table 16. Median Calendar Days by Year of Application and Program Phase for PTD Sites in Four Market Sectors

CPUC Program Phase	Median Calendar Days [a]				
	2019	2020	2021	2022	2023
Application Review	32	34	61	75	55
Site Assessment	37	40	29	38	47
Contract Issuance	43	45	42	32	41
Design and Permitting	312	361	455	429	476
Construction Complete	102	118	131	46	20
Activation	59	17	24	22	16
Start to Finish	863	863	979	896	734

[a] 2024 and 2025 are not included as no applications received in those years across Utility programs have been activated as of December 31, 2025.

The analysis of median calendar days by application year reveals three key findings:

- The duration between site application and activation peaked for customers who submitted applications in 2021 and has declined for more recent applicants.
- Design and permitting continues to be the longest duration program phase.
- Overall, the duration of construction and activation phases has decreased since 2021, indicating improved efficiency once sites advance through the design and permitting phase.

The median duration of program start-to-finish timelines initially increased by over 100 days, from 863 days for applications submitted in 2019 to a peak of 979 days for 2021 applications, before declining to 896 days and then to 734 days for applications received in 2022 and 2023, respectively. Contrary to the activation year analysis in *Analysis of Sites by Activation Year*, this pattern indicates that following a period of lengthening timelines, more recent program applicants are progressing through the program lifecycle more efficiently.

Analyzing activation timelines by application year may inherently produce shorter timelines because sites with longer durations may not yet be activated. For example, a site that entered the program in 2022 and takes four years to complete would not be included in the EY2025 analysis, whereas a site completed in two years would be included. Together, application year and activation year provide a more balanced view of overall program performance than looking at only one or the other.

Across all phases, design and permitting represents the largest contributor to overall timelines. The median duration for design and permitting has increased from 312 calendar days for applications received in 2019 to 476 days for applications received in 2023. This sustained growth suggests continued challenges associated with coordination and approval of site layout, design, easements, and conveyances.

In contrast, the time that sites spent in the construction phase has declined sharply, falling from a peak of 131 days for sites that entered the program in 2021 to just 20 for sites entering in 2023. The time sites spend in the activation phase has also decreased, falling from 59 days for applications received in 2019 to 16 days for those received in 2023. The shorter time sites have spent in both phases indicates that these processes have become more efficient. In next year's evaluation report, the Team will have more data points and potentially more findings.

Highlights

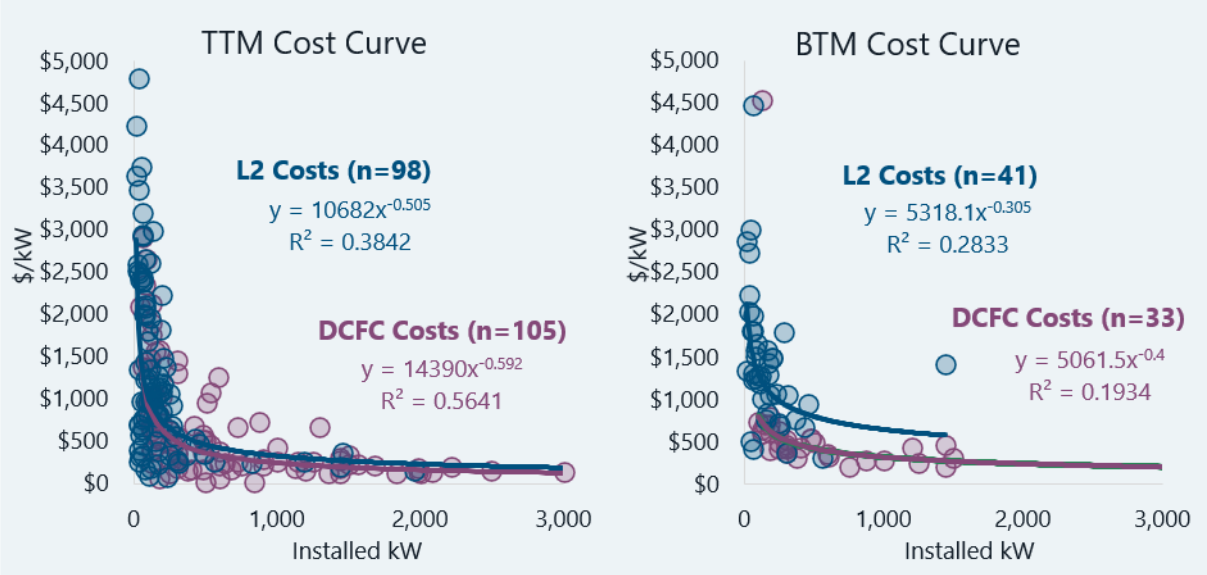
- When examining median site activation timelines in terms of activation year, the durations increase each year through 2025. However, when bundling sites by application year, the Evaluation Team observes an increase in site activation timelines through 2021 then a decline thereafter.
- The design and permitting phase continues to be the longest phase of any of the six CPUC-defined phases and has increased in duration from 312 calendar days for applications received in 2019 to 476 days for applications received in 2023.

3.3. Site Costs

3.3.1. Summary of Costs

This section examines BTM and TTM costs for financially closed-out sites in the program to date across all MDHD programs.[32] Figure 23 shows the relationship between installed capacity and the cost of TTM (left) and BTM (right). Sites with a mix of DCFC ports and L2 ports are not shown in Figure 23. The analysis includes cost information for 203 sites with a total of 154.2 MW of installed capacity and 2,846 ports through 2025.[33] Of these sites, 38 are medium-duty vehicle sites, 33 are heavy-duty vehicle sites, 85 are school bus sites, 29 are transit bus sites, and 20 are sites in other market sectors. All 203 sites in the dataset have Utility-owned TTM infrastructure. Only 74 of the 203 sites have Utility-owned BTM infrastructure; the remaining 129 sites have customer-owned BTM infrastructure.[34] The figure illustrates an L-shaped curve in which the cost per installed kilowatt declines as the installed capacity increases. At around 500 kW to 1,000 kW of installed capacity the curve flattens indicating that increasing the installed capacity leads to only modest reductions in cost per installed kilowatt. Power equations of the form $Y = Ax^b$ provide the best fit from the functions the Team attempted.

Figure 23. TTM and BTM Cost versus Installed Site Capacity for PTD Sites



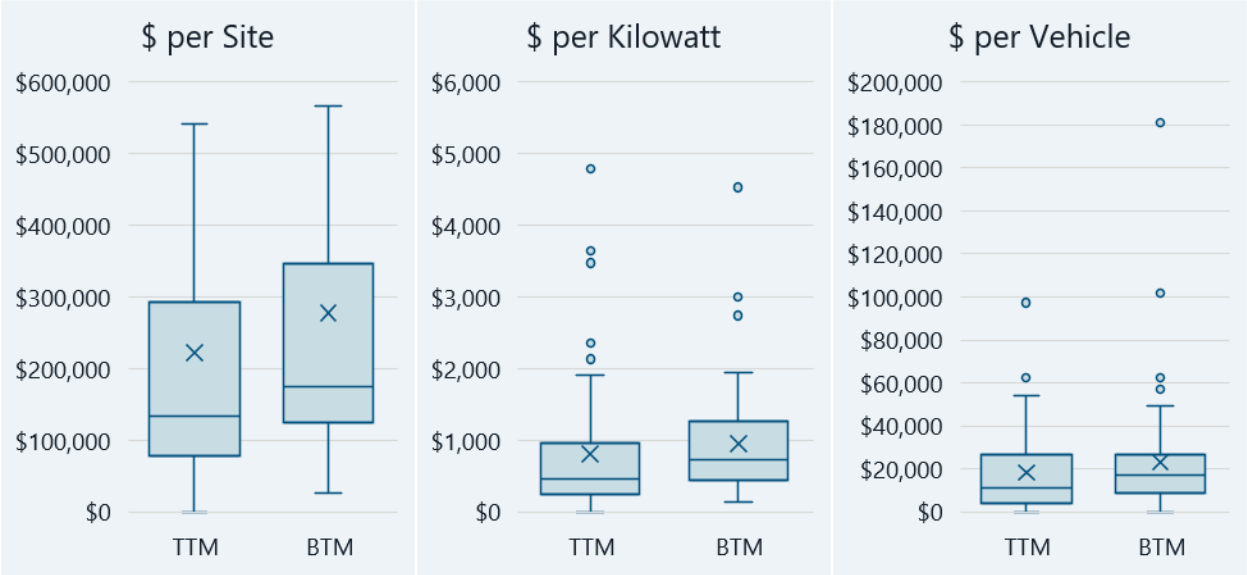
[32] Financially closed out sites are activated sites for which the Utilities have administratively completed financial paperwork.

[33] Only 203 financially closed-out sites were included in this analysis. All sites were excluded that have mixed ports (a combination of both L2 and DCFC) and have both no Utility-owned BTM and TTM infrastructure costs.

[34] Utilities do not track all actual costs for customer-owned BTM.

The figures below show Utility infrastructure costs[35] for medium-duty vehicles (Figure 24), heavy-duty vehicles (Figure 25), school buses (Figure 26), and transit buses (Figure 27). These figures include sites with both L2 and DCFC ports and therefore the site counts are higher than those in Figure 23. For each market sector, the figures include a cost per site, per kilowatt, and per vehicle. As with other box plots in this report, the X denotes the mean value, the horizontal line in the middle of the box denotes the median value, the bottom of the box denotes the first quartile, the top of the box denotes the third quartile, and the tails indicate 1.5 times the interquartile range. Outlier dots fall outside the interquartile range.

Figure 24. Medium-Duty Vehicle Costs (n=61 sites)



[35] Utility infrastructure costs include actual site installation costs borne by the Utility for both TTM and BTM (or the BTM incentive when the site infrastructure is customer-owned), including all capital and labor costs. This does not include the cost of the EVSE equipment or installation.

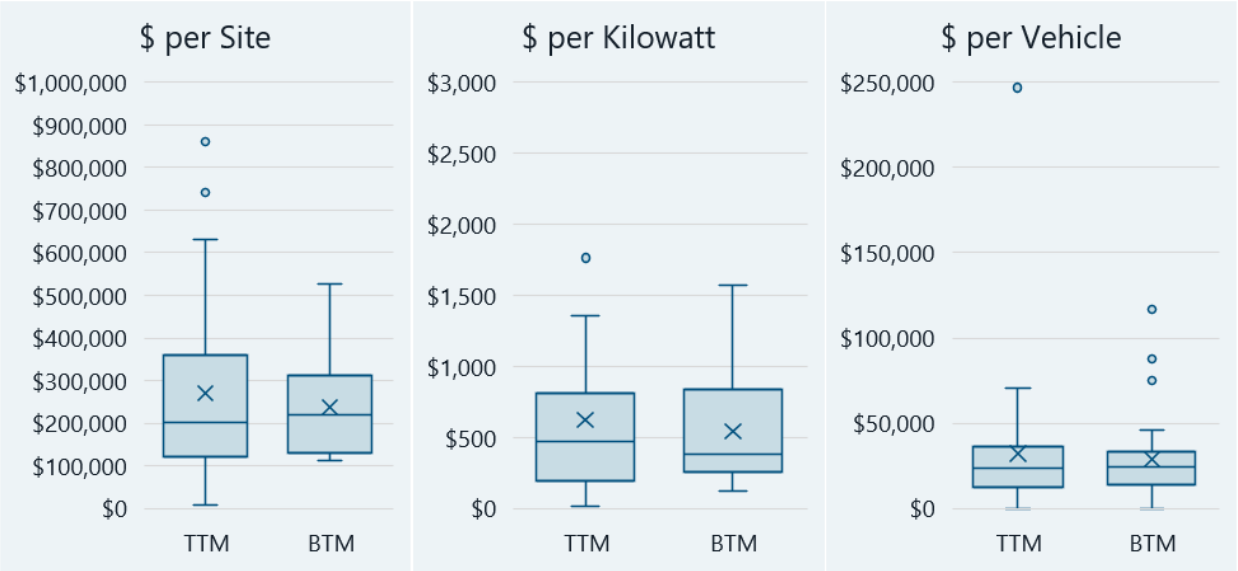
Figure 25. Heavy-Duty Vehicle Costs (n=35 sites)



Figure 26. School Bus Costs (n=103 sites)



Figure 27. Transit Bus Costs (n=32 sites)



3.3.2. Predictors of Site Infrastructure Costs

To understand the factors contributing to variation in site costs, the Evaluation Team conducted a regression analysis that predicted site costs while controlling other explanatory variables. The regression is useful for isolating the impact of individual explanatory variables holding all else constant but indicates only correlation, not causation.[36] The Team converted all costs to constant 2020 real dollars.

The main specification[37] predicts TTM cost using the following variables:

- Installed capacity (kW)
- Year of site activation or contract signing
- Project duration (years)
- Utility (SCE, PG&E, or SDG&E indicator variable)
- Location (DAC indicator variable)

[36] The Evaluation Team removed sites from the analysis that were markedly different, such as sites with on-site batteries or sites in their second phase of charger installation (e.g., sites in which TTM work was previously completed).

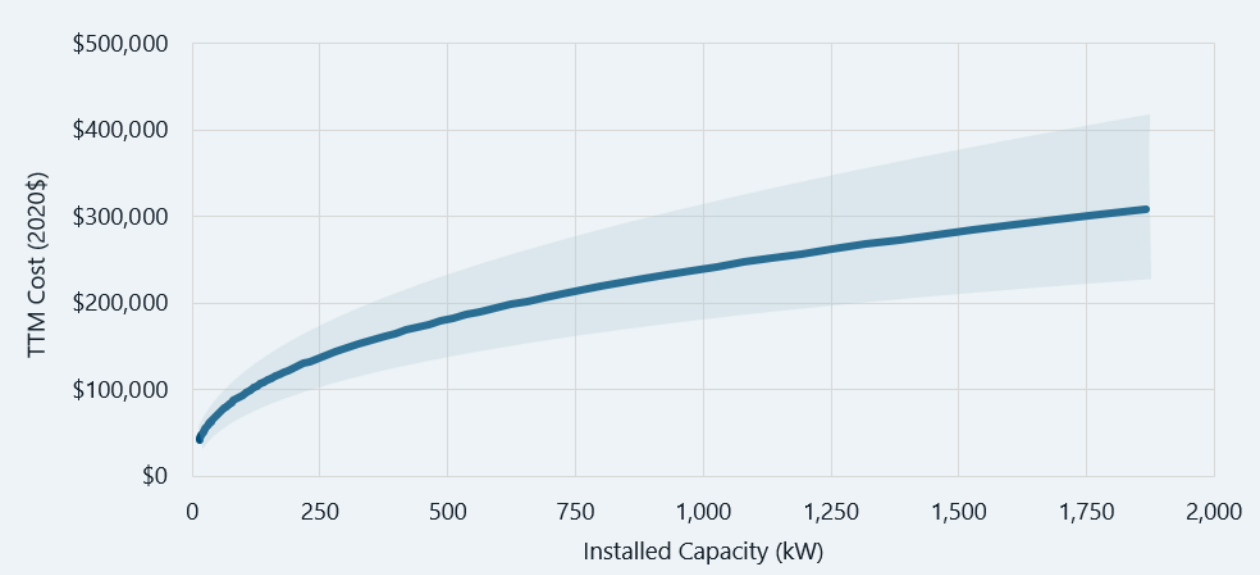
[37] This specification includes 230 observations of MDHD sites activated through EY2025. This number is larger than the number above in the *Summary of Costs* section because it includes sites with a mix of DCFC and L2 ports. The main specifications explain approximately 50% to 60% of the observed variation in project costs (adjusted R^2 = 0.5–0.6), indicating that the included variables capture slightly more than half of the key drivers of cost variation.

A second specification is almost identical to the main specification and predicts TTM plus BTM cost for the subset of sites with Utility-owned BTM infrastructure.[38] As further described below, some variables have a greater impact on predicting TTM costs than others.

Installed Capacity

In both specifications, installed capacity is strongly correlated with site cost. Results suggest that doubling installed capacity corresponds to an approximate 30% to 40% increase in site cost. As shown in Figure 28, the predicted TTM costs increase with installed capacity but at a diminishing rate. This pattern reflects economies of scale and/or the presence of fixed costs. The pattern is consistent with the cost-per-kilowatt trends presented earlier in this section (Figure 23), in which larger capacity sites show lower costs per kilowatt of installed capacity. The main difference between Figure 28 and Figure 23 is that Figure 28 controls for other explanatory variables, whereas Figure 23 does not.

Figure 28. Weighted Average Predicted TTM Costs (2020$) by Installed Capacity (kW)



Prediction line requires reference site assumption. This line assumes median construction years, non-DAC, activated in 2021. The shaded band represents a 95% confidence interval.

Site Cost Trend

The Evaluation Team used two different specifications to examine whether site costs were changing over time. The first included activation year as an indicator variable, and the second included contract year as an indicator variable. In both specifications, the year indicator variable was not a statistically significant

[38] This specification includes 77 observations of MDHD sites activated through EY2025. Actual BTM costs are only recorded for the sites with Utility-owned BTM infrastructure.

predictor of site cost.[39] Additionally, the coefficients did not increase or decrease over time, suggesting that a consistent, observed time trend does not exist.

Several explanations are possible for this lack of a time trend. On one hand, costs may decrease over time as site developers gain experience in managing site development and procuring equipment. On the other hand, costs could increase over time if the easiest to develop and simplest sites were developed early in the Utility programs, leaving fewer, less optimal and more complex sites for development later in the programs. Further, competition with other electricity infrastructure projects such as data centers, residual COVID-19 impacts, and the evolving policy landscape for charging infrastructure could also be cost drivers. Overall, the analysis above cannot isolate any one of these cost drivers and only shows the lack of a time trend.

As a sensitivity analysis, the Evaluation Team reran both specifications using a larger set of sites in the analysis, including sites in the second phase of charger installation (sites in which TTM work had already been completed). Unsurprisingly, for these estimates the Team found a statistically significant decreasing cost trend over time. This was expected since sites in their second phase have lower capital and labor costs compared with other sites. The Team prefers the cleaner specifications above showing no cost trend over time as including the sites with a second phase of charger installation creates a skewed analysis. As additional sites are financially closed out, the Evaluation Team will continue to examine these cost trends.

Disadvantaged Community Site Costs

Sites located within DACs do not exhibit statistically significant differences in site costs relative to non-DAC sites, all else equal. This finding supports the argument that sites within DACs do not have systematically different costs than sites outside of DACs.

Project Duration

The Team found that sites with longer construction timelines are generally associated with moderately higher total site costs, with each additional year corresponding to an estimated increase in cost of 5% to 10%. However, this effect is sensitive to model specification and is not as robust as other findings like the relationship between installed capacity and cost.

Highlights

- Installed capacity is a strong predictor of site cost; larger sites have higher total costs and a lower cost per-kilowatt. A doubling of installed capacity corresponds to an increase in site cost of 30% to 40%, all else equal.
- The Evaluation Team did not find a statistically significant difference in site costs for DAC versus non-DAC sites.
- Longer construction timelines are generally associated with higher site costs, with each additional year adding 5% to 10% to estimated costs.

[39] The p-value was above 0.05 for all year indicator variables in both specifications.

3.4. EVSE Maximum Demand versus Installed Capacity

The Evaluation Team's analysis should be interpreted in the context of installed capacity, site VAPs, vehicle characteristics, and individual site needs. Larger sites may initially exhibit lower utilization (measured as the maximum monthly demand by installed capacity) than smaller sites because vehicle acquisition is often phased, vehicles do not always charge concurrently, and charging infrastructure is sized to accommodate each site's full VAP. Vehicle and battery characteristics may also affect utilization. Earlier-generation vehicles often have smaller batteries and lower charging requirements than newer heavy-duty vehicles and buses. The utilization metrics are indicators of how infrastructure is being used relative to vehicle deployments to date, rather than a way to determine if a site's charging infrastructure is appropriately sized.

3.4.1. Maximum Monthly Demand by Installed Capacity

The Evaluation Team estimated the ratio of the maximum monthly demand to the installed capacity of EVSE at each site (referred to here as "monthly peak demand ratio"). This metric provides an alternative approach to measuring utilization and captures how fully a site is using its installed infrastructure. The metric ranges between 0% and 100%, with 100% indicating full use at least once per month.

To determine which sites to use for this analysis, the Evaluation Team began with 292 PTD activated sites in the MDHD programs that had AMI data available and installed EVSE capacity verified through a site visit. The Team excluded an additional 21 sites that displayed peak demand that significantly exceeded known installed capacity resulting in a total of 271 sites included for this analysis. These peak demand discrepancies are due to factors such as having EVSE installed on the same meters which are serving building loads or additional EVSE being installed on "stub outs" from previous phases under or outside of the Utility programs, and EVSE being replaced with higher power EVSE. Because the Evaluation Team was unable to confirm the new total installed capacity at the time of this writing, they were not included, however these sites show a strong indication that Utility MDHD program have successfully encouraged customers to expand charging capacity after initial operations.

Figure 29 shows the monthly peak demand ratio each month following start of operations. An operational month is defined as the first month with non-zero AMI data. Lines illustrate the median value for a given cohort of sites in a given month. For example, the dark blue line is the cohort of sites with operations beginning in 2021. By the end of 2025, this cohort has 60 months of operational data and therefore has the longest line. As an example, the value in month 60 is 53% indicating that across the 2021 cohort, the median value of peak demand ratio in month 60 is 53%.

Figure 29 shows that sites use a greater percentage of charging capacity as they age, and the steepest increases occur in the first six-month period immediately following activation. As sites mature, they tend to level off between 40% and 60% monthly peak demand ratios, although there is variability at the individual site level. Sites activated in earlier years had a higher proportion of school bus sites than sites activated in later years and often had lower-power charging (charging ports under 500 kW), while sites activated more recently tended to have a higher fraction of high-power charging ports.

The Evaluation Team observed a high degree of variation in monthly peak demand ratios among individual sites within each market sector (approximately 30 percentage points above or below the median lines). This variation may be attributable to numerous factors, including the percentage of vehicles in customer VAPs that have been delivered, variation in fleet operations and technology reliability, and seasonal operations (such as for school districts, agriculture, and holidays that involve package deliveries).

Figure 29. Monthly Peak Demand Ratios Over Time at MDHD Program Sites by Year of Activation

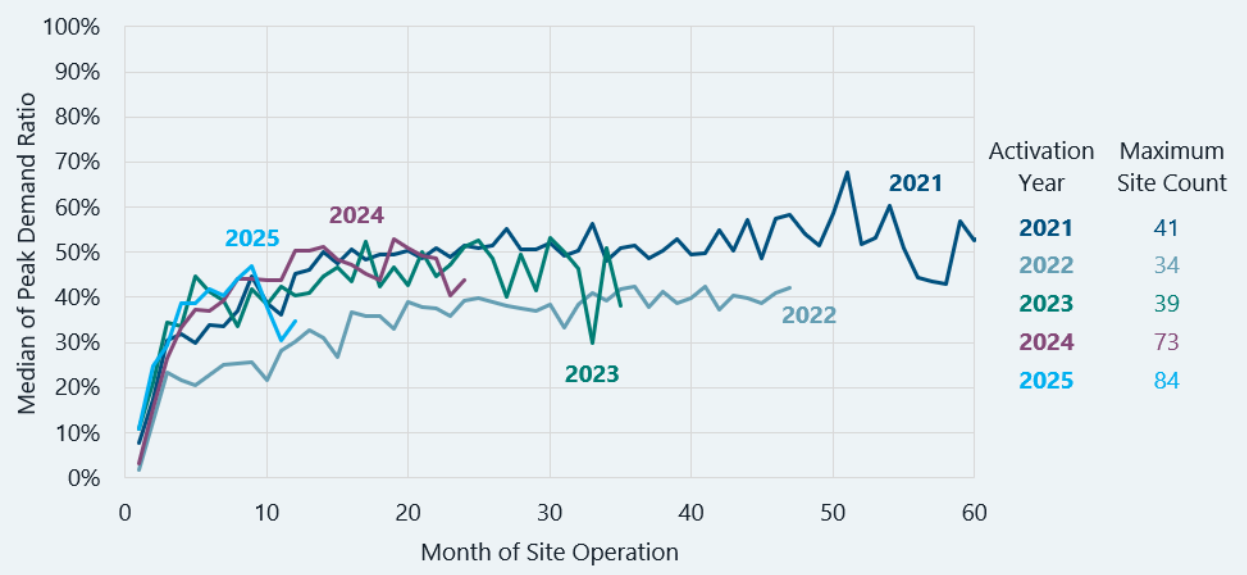
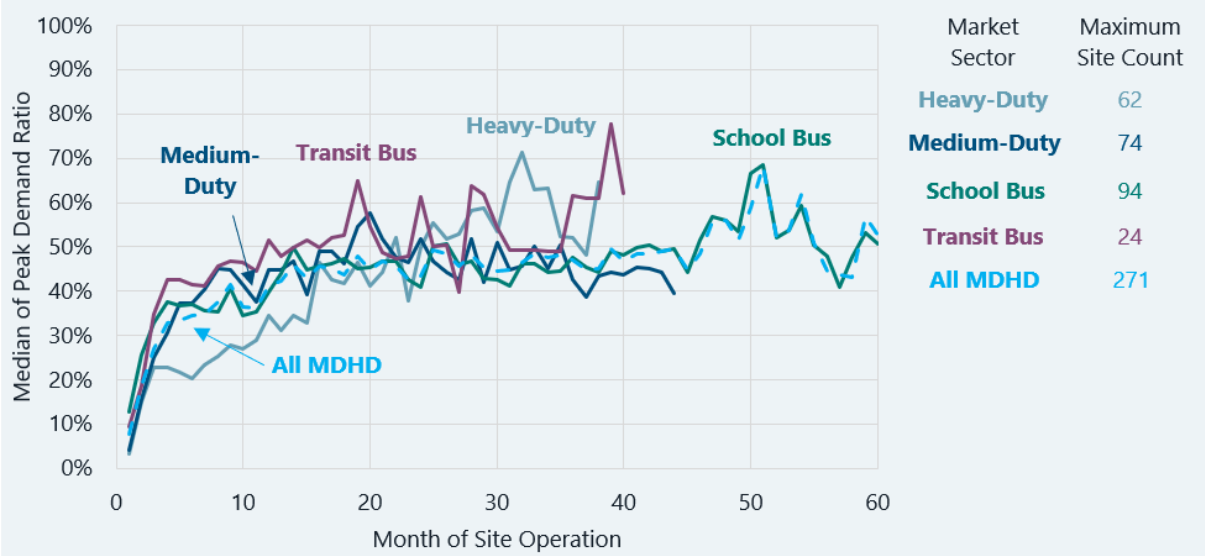


Figure 30 shows a similar graphic by market sector. Because the sample size varies between market sectors, the total number of operational months shown also varies. While 60 operational months are shown for the school bus market sector, only 38 to 44 operational months are shown for the medium-duty, heavy-duty, and transit bus market sectors (after which fewer than eight sites were operational).

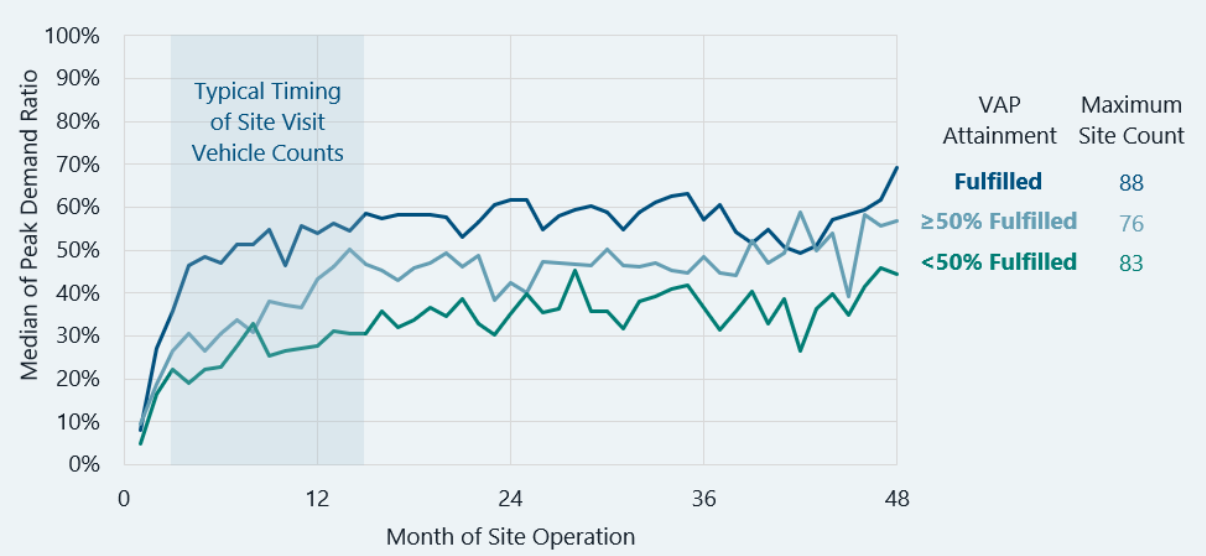
Figure 30 shows that the monthly peak demand ratio for heavy-duty vehicles grew consistently past month 30 whereas growth for the other market sectors leveled after about 12 months. One explanation for the steady upward growth in the heavy-duty vehicle market sector is the larger sites, higher vehicle counts, higher port counts, and higher installed capacity (kW) in this market sector.

Figure 30. Median Monthly Peak Demand Ratios by Market Sector



The Evaluation Team also analyzed trends in monthly peak demand ratio by customer progress toward VAP fulfillment and installed site capacity (Figure 31 and Figure 32, respectively).[40] As shown in Figure 31, the median monthly peak demand ratios for sites that have fulfilled their entire VAP (all vehicles delivered) are 23% higher on average than for sites with less than 50% of the vehicles in the VAP. This relationship is consistent with increased charging demand as a greater number of EVs are deployed into the fleet.

Figure 31. Median Monthly Peak Demand Ratios for Vehicles Observed at Site Visits

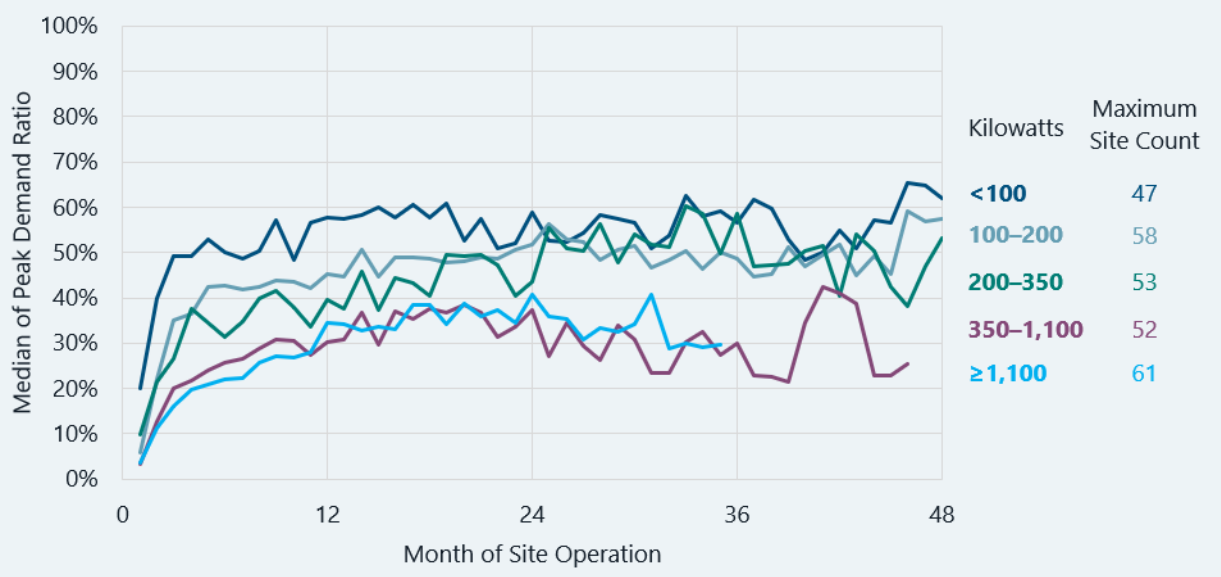


Site count is 247, because 24 sites did not have reliable data available for observed vehicles.

[40] The percentage of a site's planned vehicle deployments (specified in its VAP) that a site has obtained is determined by comparing the number of vehicles observed on site or reported by a fleet manager during a site visit with the site's total VAP vehicle quantity.

As shown in Figure 32, peak demand tends to be inversely related to total installed capacity. For example, sites with less than 100 kW of installed capacity exhibit 24% higher median monthly peak demand ratios than sites with over 1,100 kW of installed capacity. This trend likely reflects a combination of factors, including increased time required for large fleets to fulfill VAPs and a lower likelihood that large sites will concurrently use all EVSE.

Figure 32. Median Monthly Peak Demand Ratio by Installed Capacity



Analysis of monthly maximum demand trends shows that overall while peak demand has increased with site maturity and fulfillment of the site VAP, most sites have operated well below their installed capacities most of the time. Across all of the MDHD programs, 36% of sites had a median monthly peak demand ratio of over 50%, while only 17% of sites had a median monthly peak demand ratio of over 70%. Across all MDHD program sites and operational months, median monthly peak demand ratio was 41%. Findings in this section and in the *Charging Flexibility—Vehicle Energy Storage (MWh)* section suggest that the majority of MDHD sites have required less capacity to date than what was installed.

3.4.2. Maximum Lifetime Demand by Installed Capacity

As an alternative to the metric above, the Evaluation Team also investigated the relationship between maximum lifetime demand (kilowatt) and installed EVSE capacity (kilowatt). Maximum lifetime demand is defined as the highest 15-minute AMI demand interval over a site's operational life. As with the metric in the *Maximum Monthly Demand by Installed Capacity* section—peak demand ratio—maximum lifetime demand captures how fully a site uses its installed capacity. Note, the maximum lifetime demand is an extreme event and does not reflect how often high-demand conditions occur.

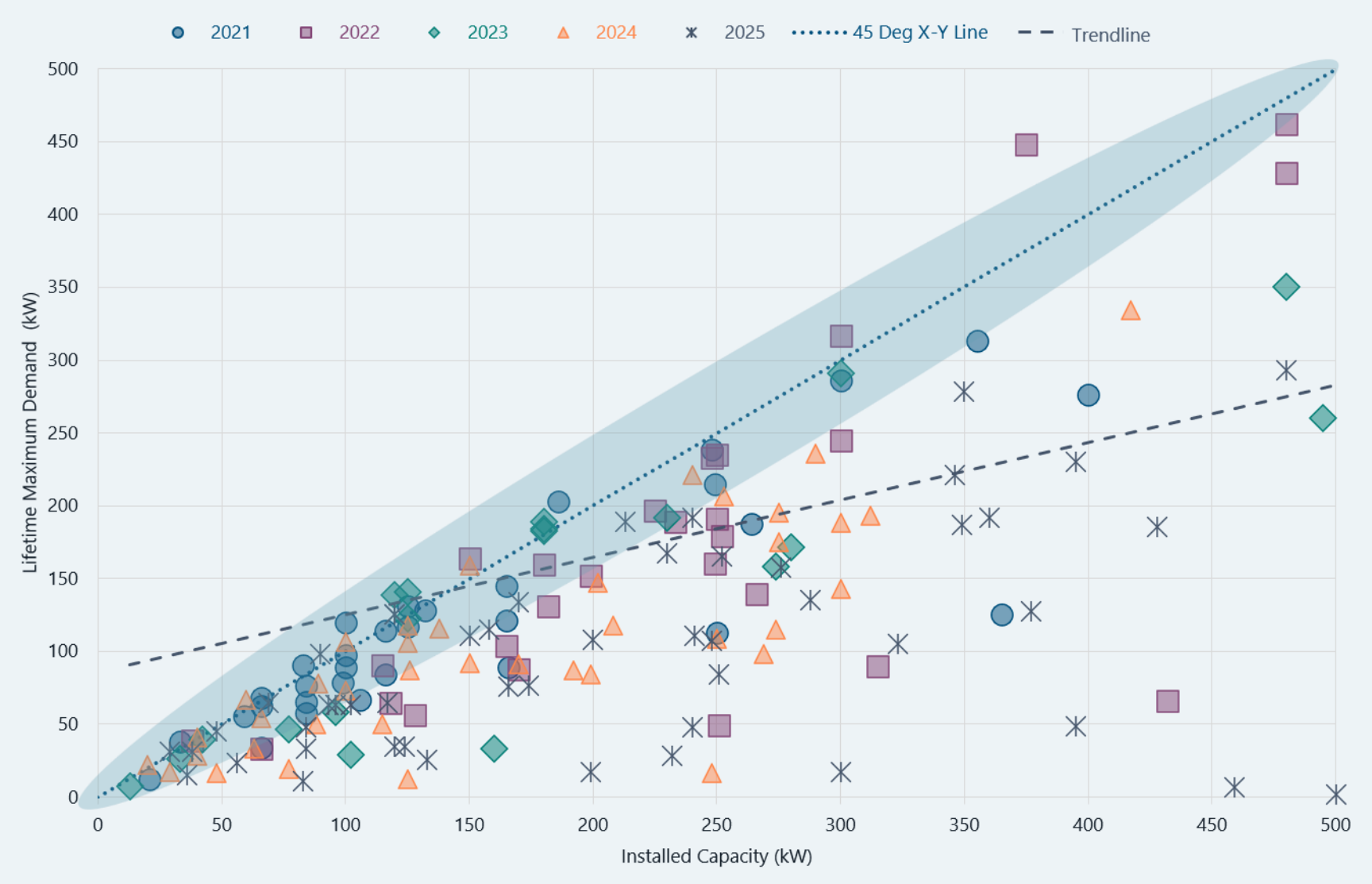
Figure 33 plots lifetime maximum demand against installed capacity, segmented again by operational year. The 45-degree Y=X line represents the theoretical condition in which a site's maximum demand equals its installed capacity (a 100% peak demand ratio), with the shaded band (90% to 110%) encompassing sites operating near this maximum. To avoid compressing the data, which would adversely

affect readability, Figure 33 caps both lifetime maximum demand and installed capacity at 500 kW, eliminating 19% of the 260 MDHD sites.[41] Unlike figures in the *Maximum Monthly Demand by Installed Capacity* section, which are based on median values across year cohorts, Figure 33 plots individual sites.

Figure 34 extends the analysis in Figure 33, plotting lifetime maximum demand against installed capacity for sites with between 500 kW and 7,500 kW for both variables. This expanded view shows that larger-capacity sites follow the same patterns the Team observed among smaller sites, with larger sites being more likely to operate below their designed capacity. The Team eliminated a single outlier site with significantly higher capacity than shown in Figure 34 to avoid compressing the data and limiting readability. This outlier site exhibited behavior similar to that of the broader site cohort.

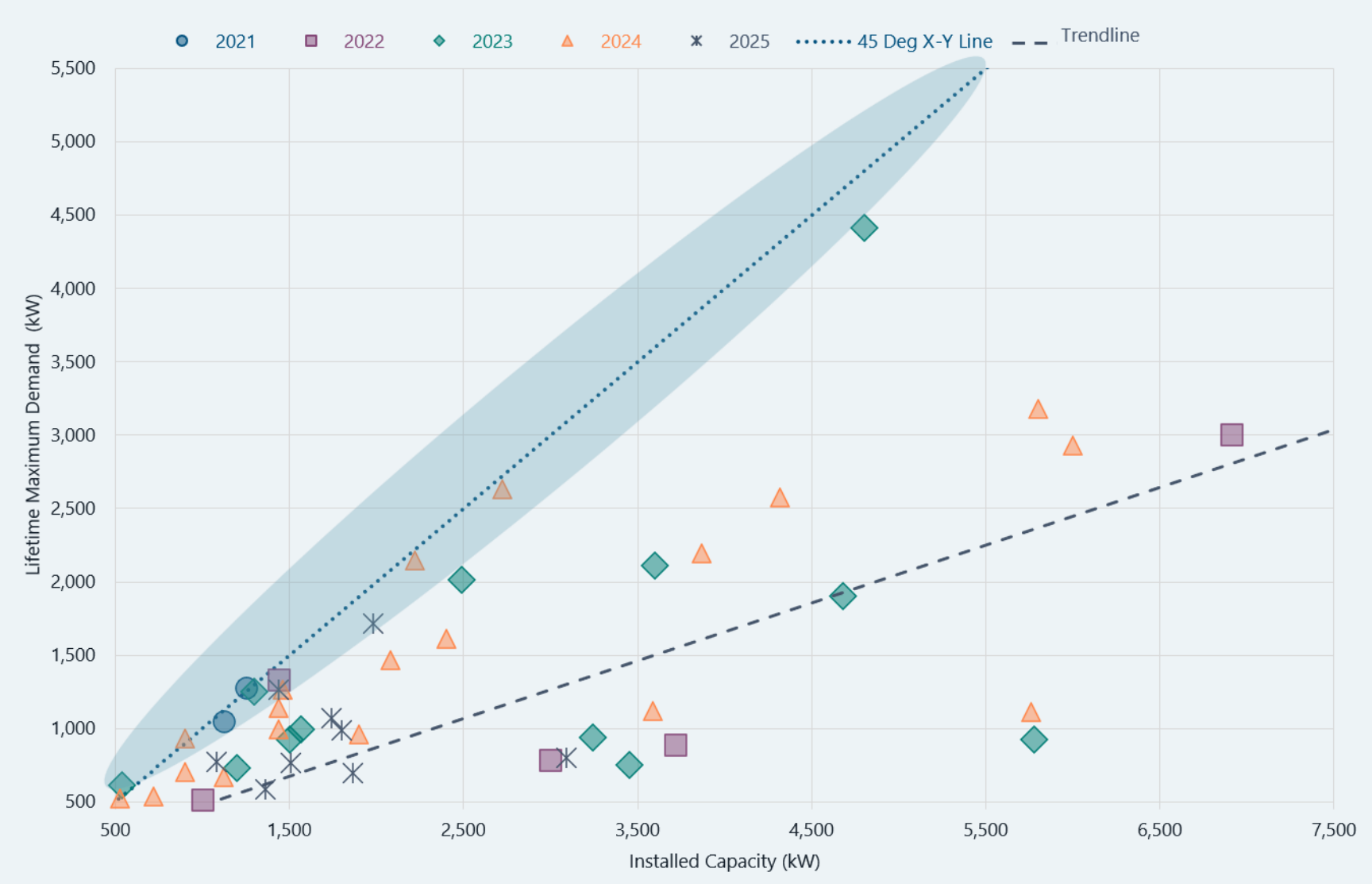
[41] The Team excluded an additional 11 sites from the 271 MDHD sites included in the monthly utilization analysis because their lifetime maximum demand data results in a higher-than-expected peak demand ratio that exceeds intentionally designed buffers in system electrical capacity.

Figure 33. Lifetime Maximum Demand vs. Installed Capacity by Site Operational Year for Sites up to 500 kW



Sites occasionally exceed nameplate capacity (the maximum electrical power output that a charger is rated to deliver under standard operating conditions) due to intentionally designed buffers in system electrical capacity.

Figure 34. Lifetime Maximum Demand vs. Installed Capacity by Site Operational Year for Sites between 500 kW and 7,500 kW



Sites occasionally exceed nameplate capacity due to intentionally designed buffers in system electrical capacity.

Figure 33 and Figure 34 highlight that many sites have their lifetime maximum demand well below the installed capacity and that sites with greater installed capacity are more likely to operate below their capacity. The figures also indicate that sites with longer operating histories are more likely to experience peak demand events that approach installed capacity as indicated by the prevalence of sites that became operational in 2021 (42% of 36 sites) and 2022 (20% of 35 sites) sites falling within the shaded band, compared with sites that became operational in 2024 (13% of 71 sites) and 2025 (7% of 82 sites).

Highlights

- Larger and newer sites are more likely to have maximum demand below the installed capacity when maximum demand is measured on a month-to-month or lifetime basis.
- As sites mature, the median site uses between 40% to 60% of its installed capacity when measured on a monthly peak demand basis.
- Market sectors grow at different rates following site operation, with heavy-duty vehicles sites growing the slowest.
- The Evaluation Team did not assess whether low utilization of charging infrastructure is intentional on the part of the fleet, the result of changing market conditions, or part of the fleet's long-term plan.

3.5. Grid Impacts

3.5.1. Load Management Deep Dive

The Evaluation Team investigated factors that drive load management decisions among fleets. In past evaluation reports, the Team observed a large proportion (approximately 80%) of fleets do not use load management to mitigate electric utility bills. Approximately 40 fleets representing over 60 PTD sites participated in an interview process. The Team recruited sites that had the largest potential savings in energy, emissions, and utility bills. The fleets that the Evaluation Team interviewed account for nearly 60 MW of installed capacity and 30 MW of observed demand. These fleets were spread across all three Utilities and all vehicle market sectors and had from one to six years of operational experience. The full Load Management Deep Dive can be found in *Appendix A*.

Benefits of Load Management

- Controls vehicle charging to meet operational needs while reducing unnecessary high-cost consumption or maximum demand.
- Can lower electricity costs by shifting charging to lower-cost time periods.
- May enable more vehicles to charge with existing charging infrastructure.
- Supports grid and operational reliability, including responding to demand response events.

The Team identified two main barriers to load management:

1. Many fleets are aware of the service reliability of their EVs and charging stations but are unaware of their energy usage and utility bills, the relationship between the two, and the potential to lower their bills. This report helps identify the lowest achievable average cost of energy.
2. Very few NSPs provide load management software to fleets, and even fewer provide consistent customer support to help fleets initiate and maintain load management. Because fleets sign multiyear contracts, this lack of support can prevent fleets from minimizing costs for many years.

Why Fleets Should Utilize Load Management

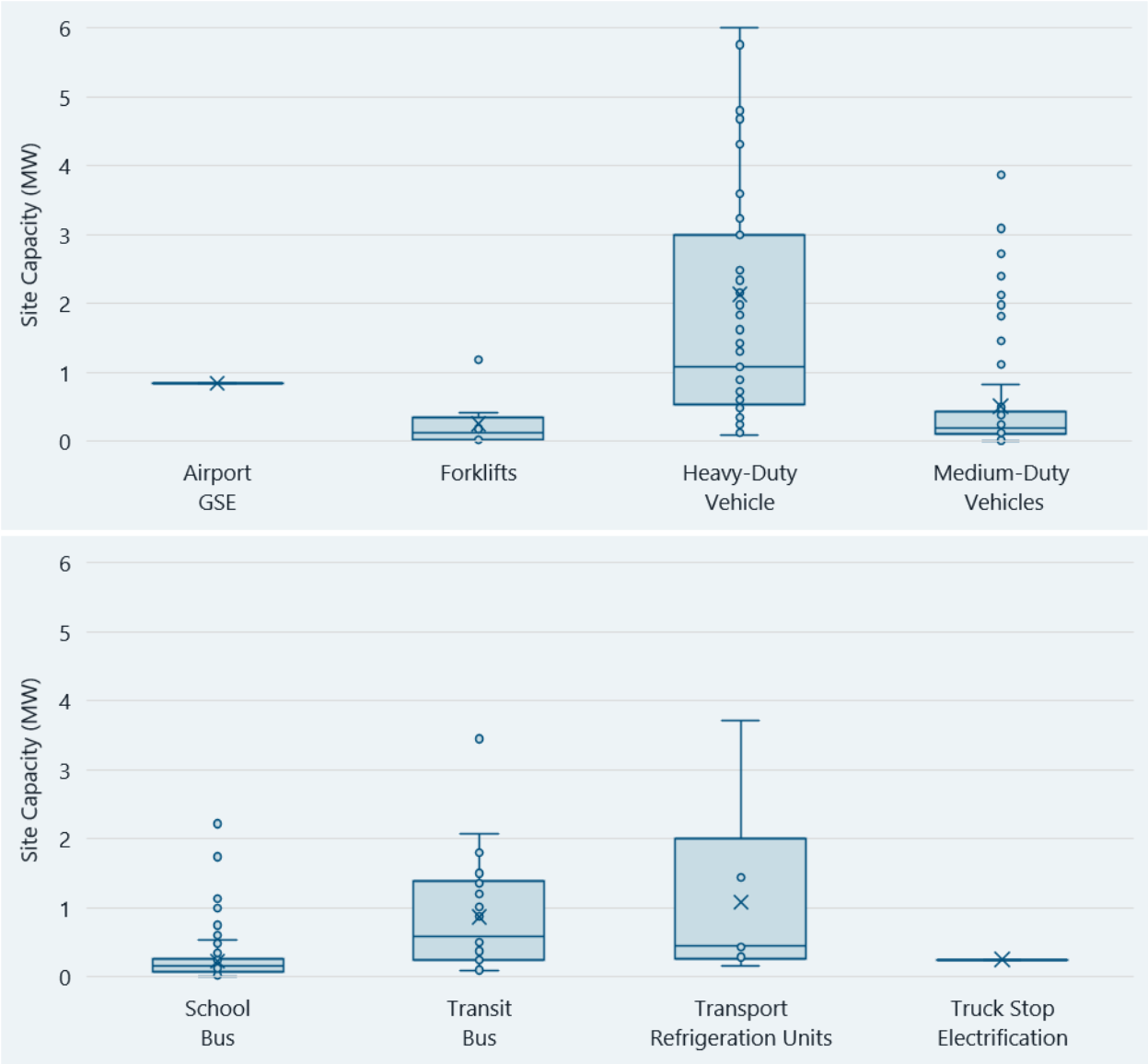
- Lowest-cost way to scale fleet electrification
- Reduces charging costs
- May defer utility infrastructure investments and mitigate consumer capital (build out) costs
- Maximizes utilization of existing electrical capacity
- Ensures that vehicles are ready for service when needed

The main solution identified by fleet managers was more NSP support. Fleet managers reported wanting ongoing information about their energy and billing trends and achievable energy costs. They also said that NSPs should proactively initiate load management rather than reactively initiative it. Finally, fleet managers expressed a need for exit strategies for contracts with underperforming NSPs. Fleets and ratepayers would benefit from publicly funded programs that ensure that qualified NSPs both offer load management and achieve a high level of fleet participation.

3.5.2. Installed Charging Capacity

Figure 35 shows the distribution of average installed charging capacity per site by the four main vehicle market sectors across all Utility programs. The heavy-duty vehicle sector has both the highest average installed capacity (approximately 2.1 MW) and the largest variation in site capacity. Approximately 25% of heavy-duty vehicle sites have been built with less than 500 kW of capacity and two to four ports, while 14% have installed capacity exceeding 5,000 kW. School bus sites have the lowest average installed capacity of 230 kW per site. Transit bus sites average 870 kW and typically use DCFC charging. The four main vehicle market sectors shown below account for 96% of built capacity across all MDHD programs. Notably, while there are relatively few TRU sites, these sites tend to be large installations with average capacity of almost 1,100 kW.

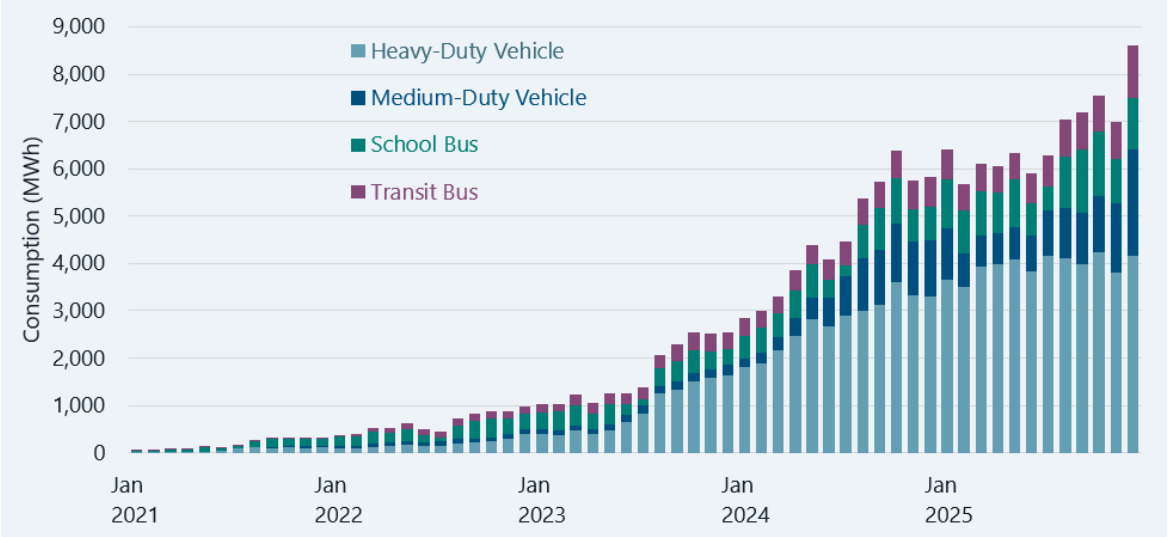
Figure 35. Average Installed Charging Capacity per Site by Market Sector, All Utilities



3.5.3. Monthly Energy Consumption Total for Main MDHD Market Sectors

Figure 36 shows total energy consumption by month across four market sectors for all MDHD programs. Notably, the figure shows a steep increase in energy consumption by medium-duty vehicle sites in late 2025, driven by a few sites with a large fleet that has been active since 2024. Transit bus and school bus sites continued to show increased energy consumption but at a slower rate. Transit bus sites have maintained a steady trend year over year, while school bus sites typically showed slightly higher energy consumption (around 25% monthly by end of year) that was more sporadic and seasonal. Heavy-duty vehicle sites showed consistent usage, averaging 4,000 MWh per month throughout the year. However, at the time of the site visits in 2025, many of these sites had not received all of their vehicles or fully placed them into service.

Figure 36. Cumulative Monthly Energy Consumption by Market Sector, 2021–2025



Maximum Monthly Demand Portfolio and Main MDHD Market Sectors

Figure 37 shows total maximum demand by month for the four market sectors and a combined total maximum demand. The heavy-duty vehicle market sector accounts for the largest demand across programs (nearly 30 MW; doubling since 2024), representing approximately two-thirds of all combined demand. Across all MDHD programs, peak demand reached 38 MW on Tuesday, December 2, 2025, at 9:30 p.m., nearly 20 MW higher than at 10 a.m., when most school buses were charging at their peak. Notably, school bus evening peaks tended to occur at two different times, based on whether the sites used load management. As more school districts implement load management, their demand spike may be as prominent as that of transit bus and heavy-duty vehicle sites. Through the end of 2025, sites in other market sectors, including forklift, TRU, truck stop electrification, and airport GSE, accounted for less than 500 kW of aggregate maximum demand.

Figure 37. Maximum Monthly Demand by Market Sector, PTD Sites

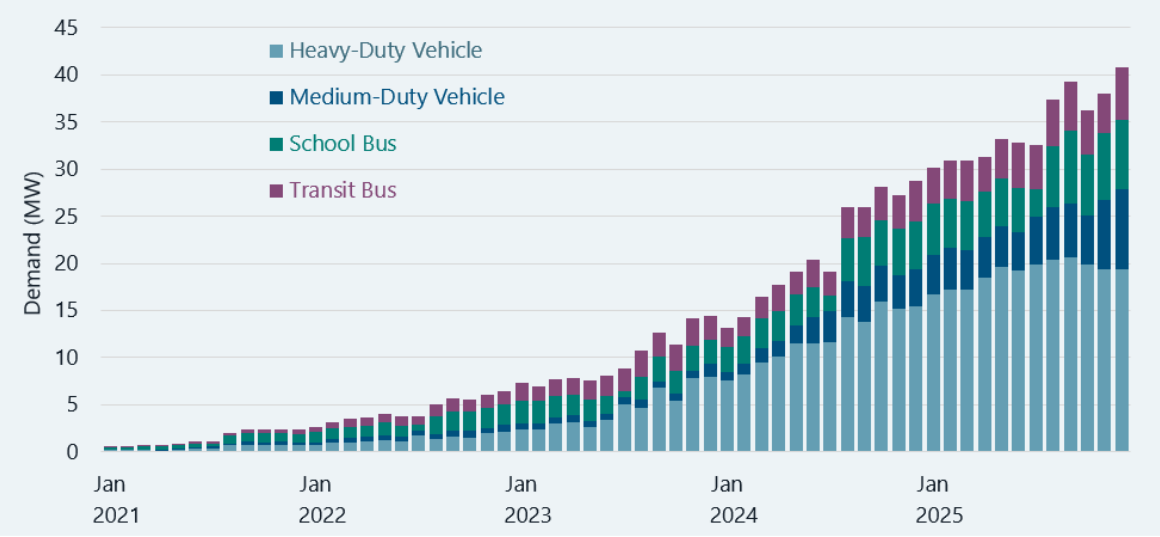
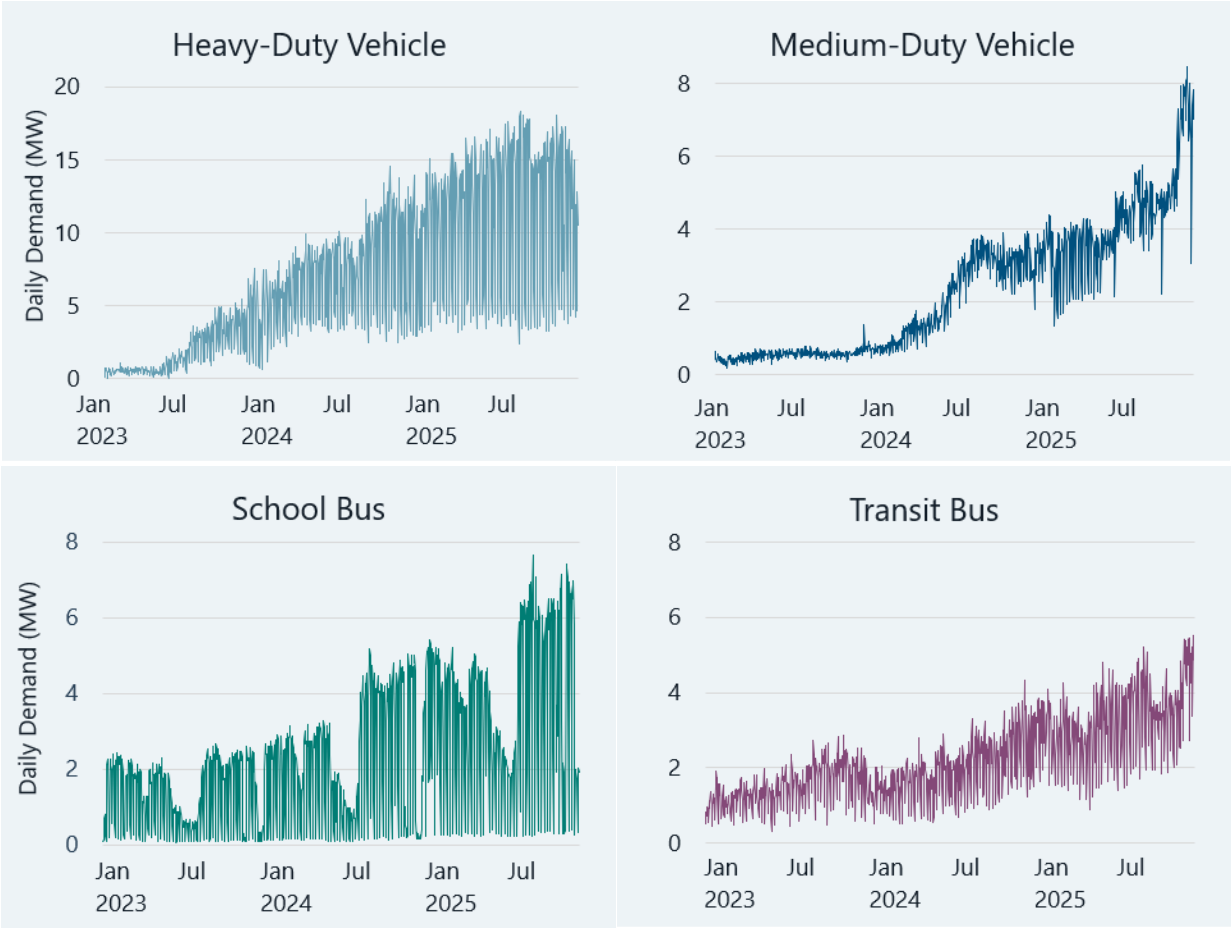


Figure 38 shows the variability in daily demand over the past two years for each of the four market sectors. As in the figure above, medium-duty vehicles show steep growth, while transit and school buses show slower growth. Demand in the heavy-duty vehicle market sector grew consistently for two years.

Figure 38. Variations in Minimum and Maximum Daily Demand by Market Sector, 2023–2025



To maximize readability, the scale for the heavy-duty vehicle market sector differs from that of the other market sectors.

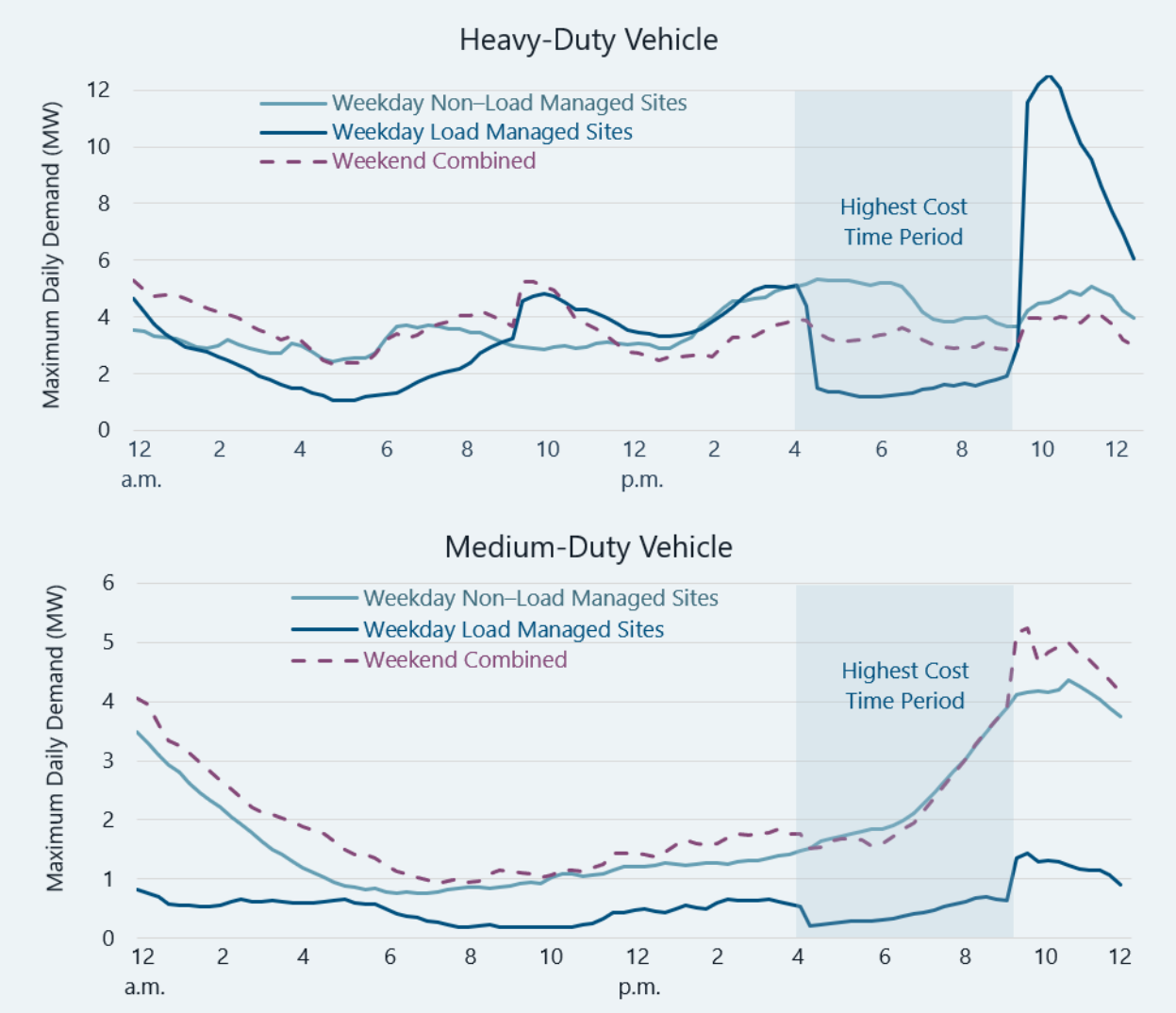
Daily Load Curves

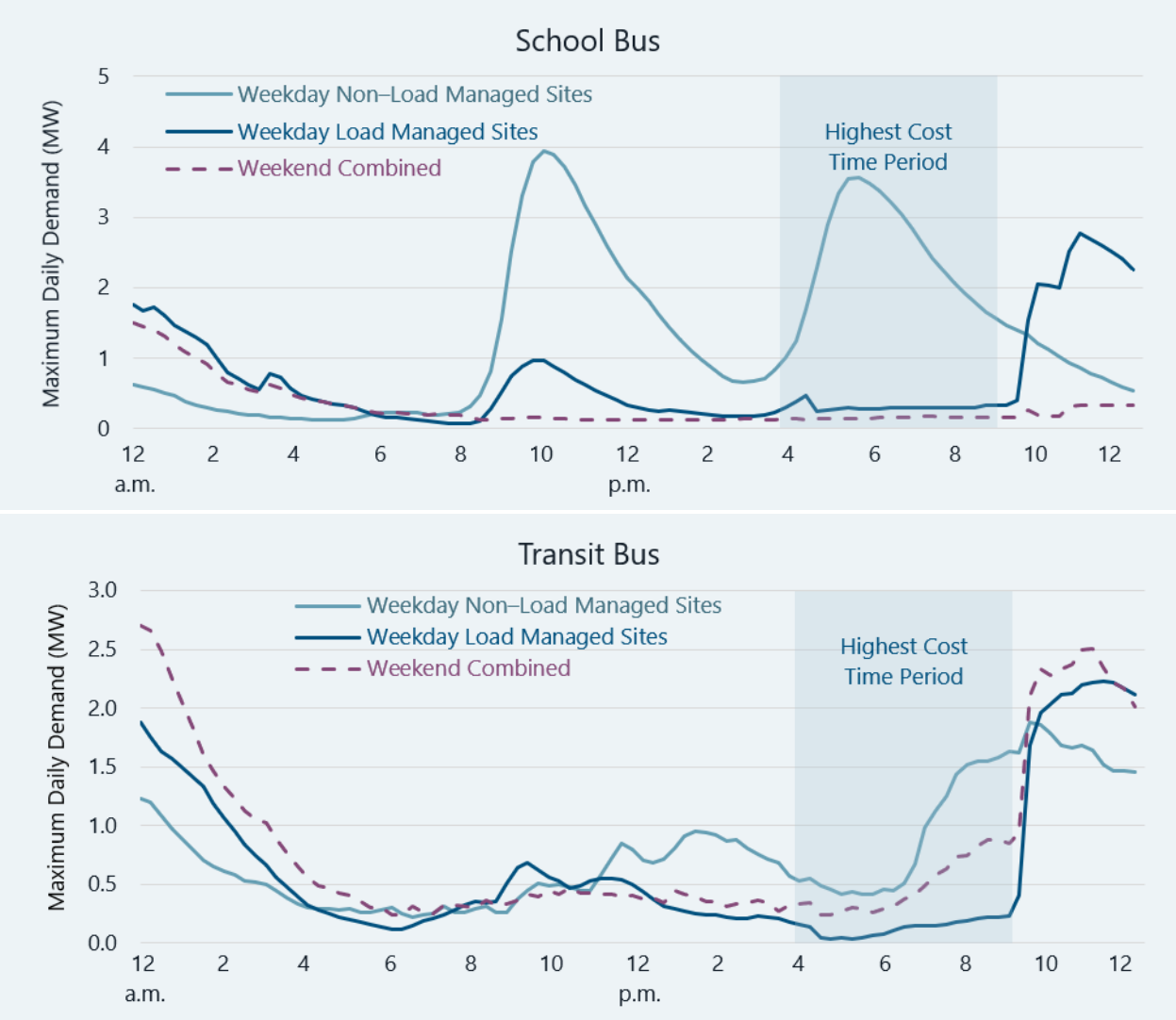
Figure 39 shows the average daily weekday demand by market sector, grouped by sites that used load management and those that did not, and the combined weekend demand of the two groups. Weekend charging is almost nonexistent for school buses and heavy-duty vehicles. Medium-duty vehicles show significant weekend charging activity, likely due to a large share of package-delivery vehicles. Transit buses also show significant weekend charging. At transit bus and heavy-duty vehicle example sites, Saturdays had reduced operations compared with Fridays and Sundays.

Heavy-duty vehicles show the most prominent use of load management, though all market sectors show signs of load management. The non-load-managed curves from the other three market sectors show a clear ramp-up in demand from 4 p.m. to 9 p.m., with the majority of that flexible enough to shift

elsewhere based on their load-managed counterparts. Analysis suggests that most of the driving on Fridays and some on Thursdays could be shifted to Saturday afternoons as fleets improve operational understanding of their key metrics, such as the size of charging sessions relative to battery size.

Figure 39. Market Sector Combined Weekend and Weekday Load-Managed and Non-Load-Managed 2025 Q4 Average Daily Load Curves





3.5.4. Time Charging Flexibility

The Evaluation Team used site charging data to determine the amount of time vehicles of each market sector were connected to a charging port but not actively consuming energy. This allowed the Team to assess charging flexibility, or the ability for a vehicle to shift charging from periods of high-cost electricity to periods of low-cost electricity without impacting current vehicle operations. Figure 40 shows the charging flexibility of the fleets in each of the four market sectors, highlighting charging sessions that overlap with the highest-cost period, 4 p.m. to 9 p.m., with details broken out in Table 17 below. The legend indicates the proportion of total session energy per market sector. Approximately 50% to 80% of all charging sessions overlap with the peak period.

The framed "very flexible" window in the figure highlights that, especially for medium-duty vehicles and school buses, there is flexibility of five hours or more to shift this energy to other time periods. Transit buses and heavy-duty vehicles show the least flexibility at around 20% of their total energy.

Figure 40. Charging Flexibility for PTD Sites in Sessions Overlapping the Time Period Between 4 p.m. and 9 p.m.

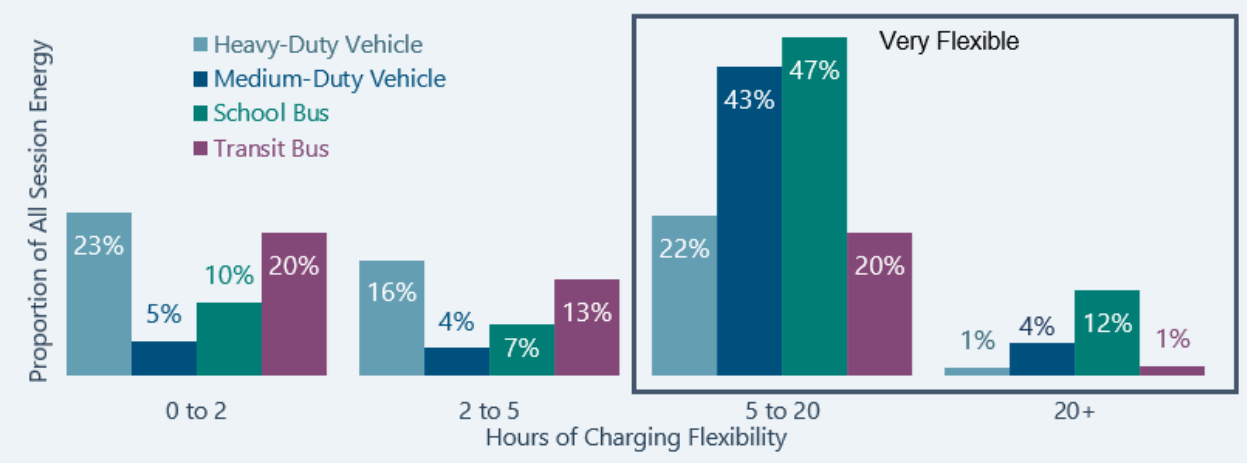


Table 17. Charging Sessions that Overlap with Peak Periods by Market Sector

Market Sector	% OLS	Overlapping Sessions (1,000)	Total Sessions (1,000)	Energy from Overlapping Sessions
Heavy-Duty Vehicle	61%	245	404	62%
Medium-Duty Vehicle	68%	242	355	56%
School Bus	52%	143	277	76%
Transit Bus	77%	59	77	54%

The Team used charging data to derive several notable findings (summarized in Table 18):

- Charging during peak periods was two times more expensive for PG&E and SDG&E school bus sites, and six times more expensive for SCE school bus site customers than charging during the lowest-cost time period.
- MDHD sites using load management reduced high-cost energy use by half on average.
- Transit bus and school bus sites using load management reduced high-cost energy by 75%.

Table 18. Energy Consumption of Load-Managed and Non-Load-Managed Sites by Market Sector

Market Sector	Load-Managed			Non-Load-Managed		
	GWh	GWh OP	% On Peak	GWh	GWh OP	% On Peak
Heavy-Duty Vehicle	30.8	3.5	11%	20.5	3.73	18%
Medium-Duty Vehicle	4.65	0.406	9%	9.6	1.94	20%
School Bus	4.07	0.255	6%	7.7	2.5	32%
Transit Bus	4.152	0.156	4%	4.715	0.655	14%

3.5.5. Charging Flexibility—Vehicle Energy Storage (MWh)

This section supplements the charging flexibility analysis above by looking at daily battery use and remaining available capacity. The smaller the percentage of battery capacity a fleet uses on a daily basis,

the greater the opportunity the fleet has to shift load. The following section presents estimates of average daily battery usage for vehicles across the four largest MDHD program market sectors. Estimating the percentage of battery capacity a vehicle uses each day enables the Team to determine the percentage of remaining battery capacity. If fleets were to use this remaining battery capacity for vehicle operations before initiating charging sessions, fleets could charge vehicles less frequently and shift consumption to lower-cost time periods through load management.

The first step to estimating average daily battery usage is to examine daily charging behavior. Figure 41 presents three years of daily charging consumption trends for each of the four market sectors.

Figure 41. Daily Consumption by Market Sector, 2023-2025

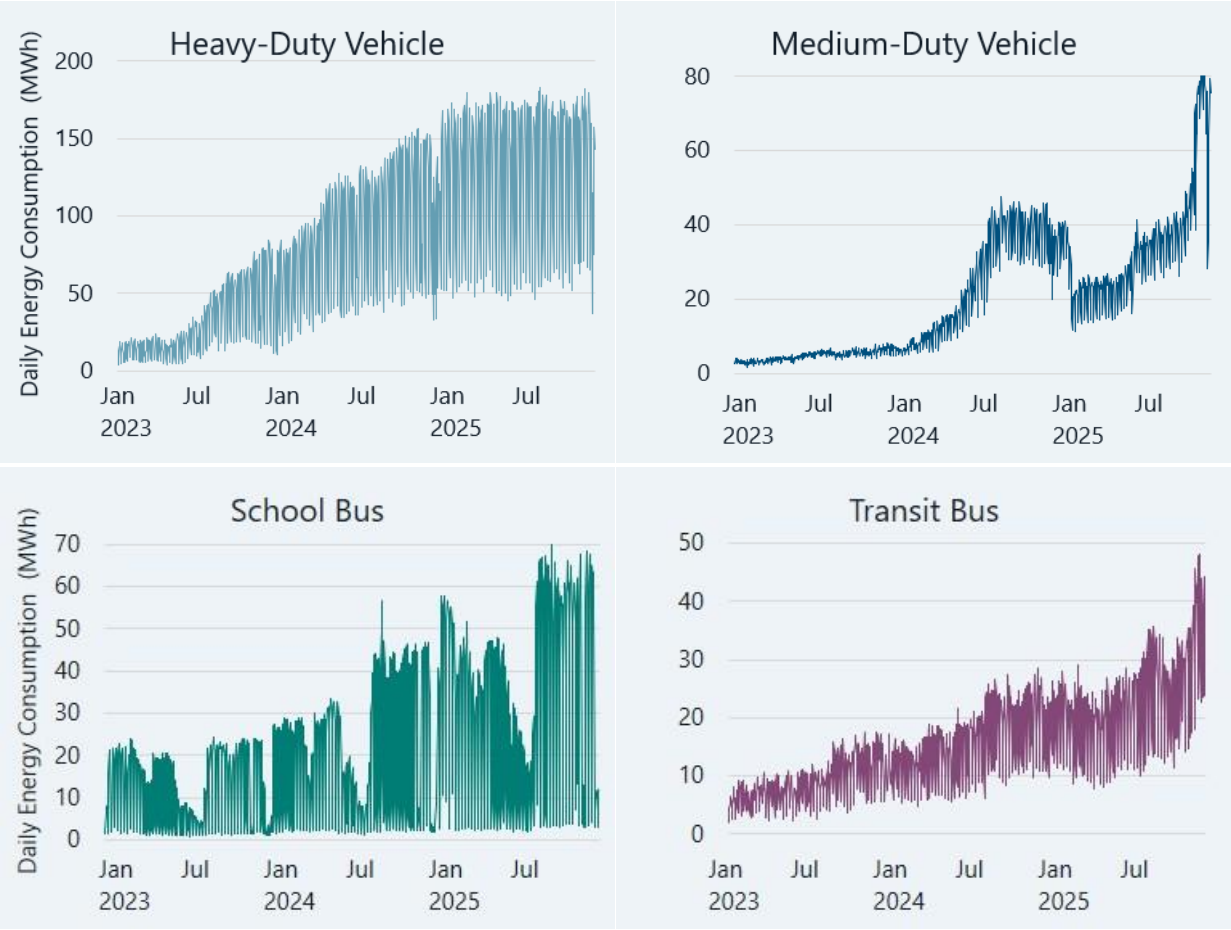


Table 19 summarizes the highest daily consumption for vehicles in the four market sectors and compares this value with the average size of vehicle batteries and total available energy storage across the four market sectors. The Evaluation Team collected information such as battery size and vehicle count through site visits. Because site visits occurred once during the year, and the maximum daily consumption, which is a measure of the consumption for all vehicles, likely occurred at the end of the year when sites had more vehicles to charge, the average daily battery usage values in the far-right column of Table 19 are likely overestimates.

The table presents the following metrics:

- **Total Vehicle Count:** Total number of vehicles observed during site visits. Vehicles delivered after site visits were conducted are not included in this total.
- **Average Battery Capacity:** The average battery capacity of all vehicles within each market sector observed during site visits.
- **Total Battery Capacity:** Derived by multiplying Total Vehicle Count by Average Battery Capacity. Because Total Vehicle Count is lower than the actual number of vehicles (because it does not include vehicles delivered after site visits), the actual total battery capacity is likely higher than the figure presented.
- **Maximum Total Daily Consumption:** Total consumption as observed through AMI data. This total is based on actual fleet operations, so it includes consumption from vehicles that were added after site visits.
- **Average Daily Battery Usage:** Derived by dividing total daily consumption for all vehicles by total battery capacity for all vehicles. Because actual total battery capacity is likely higher than included in Table 19, the average daily battery usage percentage is likely lower than the values presented in the table (i.e., total consumption is spread over a greater number of vehicles, and therefore average usage is lower).

Table 19. Verified Delivered Vehicle Battery Capacity and Daily Consumption

Market Sectors	Total Vehicle Count	Average Battery Capacity (kWh)	Total Battery Capacity, All Vehicles (MWh)	Maximum Total Daily Consumption, All Vehicles (MWh)	Average Daily Battery Usage (%)
Heavy-Duty Vehicle	854	454	388	175	45%
Medium-Duty Vehicle	1,324	118	156	80	51%
School Bus	853	166	142	65	46%
Transit Bus	237	395	94	45	48%
Total	3,268	N/A	780	365	N/A

Average daily battery usage for each of the four market sectors is roughly 50%; however, many school buses charge twice daily, which causes the average daily battery usage to fall to around 25%, as the increased number of charging sessions reduces the available battery capacity. As average usage decreases, charging flexibility increases. A fleet with a low average daily battery usage percentage that has implemented load management could further optimize charging to minimize cost and emissions without impacting operations. A low average daily battery usage percentage may also indicate that a fleet has oversized its vehicle batteries.

3.5.6. Average Energy Pricing by Billing Month in 2025

Utility rates have remained fairly consistent over the past several years across Utilities. Although each Utility has at least two EV tariff options, they are overall similar to the EV tariffs presented in Table 20. For PG&E and SDG&E customers, energy costs during high-cost periods in 2025 were at least double those in

the lowest-cost periods. SCE's customers paid three to four times more during high-cost periods than during low-cost periods in the winter, and six times more during the summer, when on-peak charging costs were the highest. This pricing sends a clear signal and incentive for customers to shift charging if they are aware of this pricing difference. On the other hand, without demand-oriented costs, many of these fleets were charging at the right time, but much faster than the data suggest is needed. Demand-oriented costs could help customers have less impact on the grid by slowing down charging.

Table 20. Utilities' High and Low EV Tariff Pricing

Utility Tariff [a]	SDG&E EV-HP	SCE TOU-EV-8[b]	PG&E BEV1
Low Cost Per Kilowatt-hour	$0.12	$0.14	$0.17
High Cost Per Kilowatt-hour	$0.24	$0.58	$0.40
Ratio of High Cost to Low Cost	2.0	4.1	2.4

[a] Tariff pricing does not include taxes or demand-oriented costs

[b] SCE's highest pricing is in summer, and its lowest pricing is in winter.

Compared with Utility tariff energy costs, billing data show what customers actually pay for energy on a monthly basis. Figure 42 shows the monthly electricity costs for all MDHD sites across each market sector (on the x-axis) and the proportion of charging that occurred from 4 p.m. to 9 p.m. during that billing month (on the y-axis). The lowest, very infrequent average cost per kilowatt-hour is approximately $0.15/kWh, and few billing months have energy consumption costs below $0.25/kWh. This is 65% higher than the lowest Utility rates. The scatterplot in each figure helps summarize the frequency of the average billed kilowatt-hour.

Figure 42. 2025 Monthly Average Electricity Costs and Portion Occurring During Peak Periods by Market Sectors

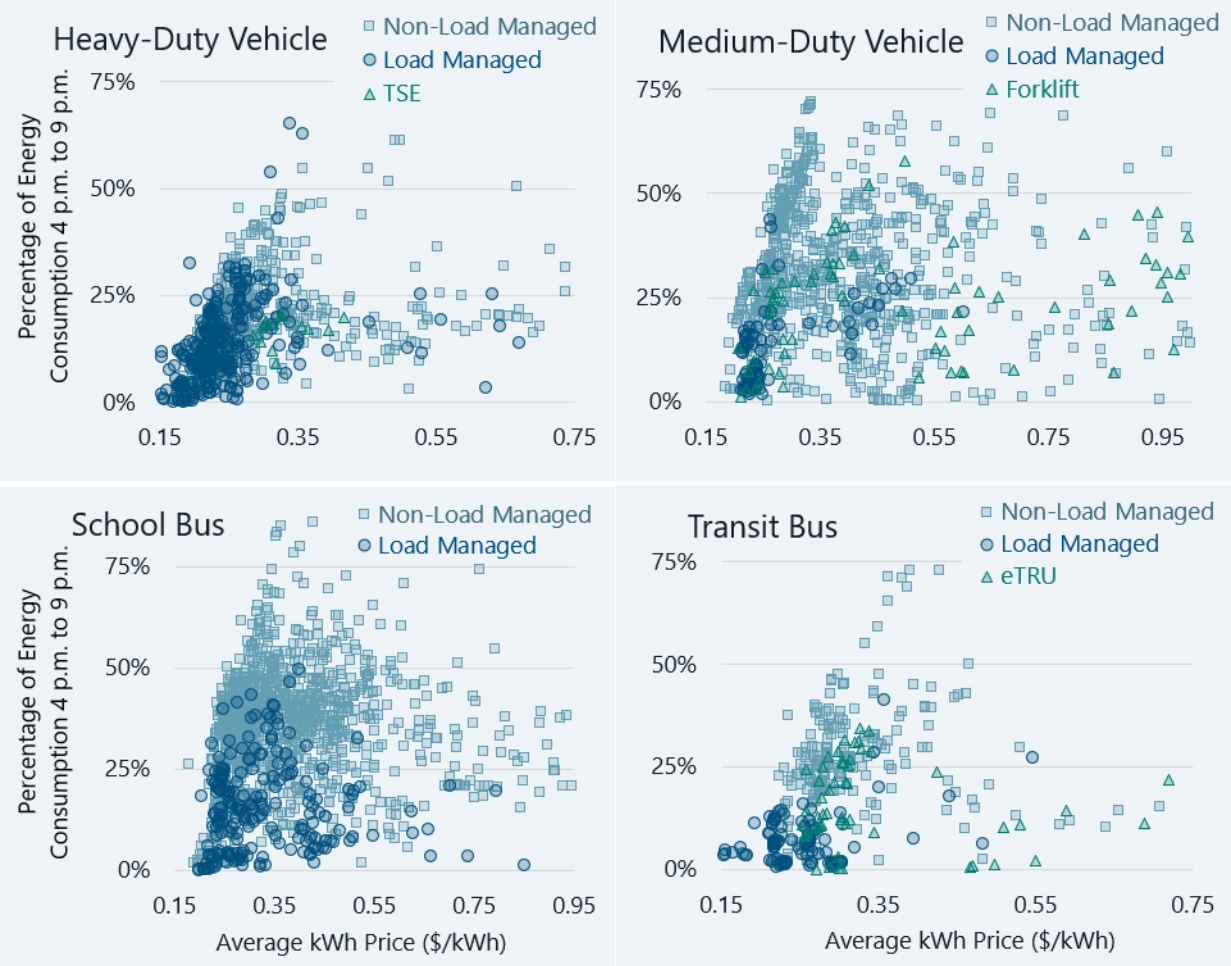
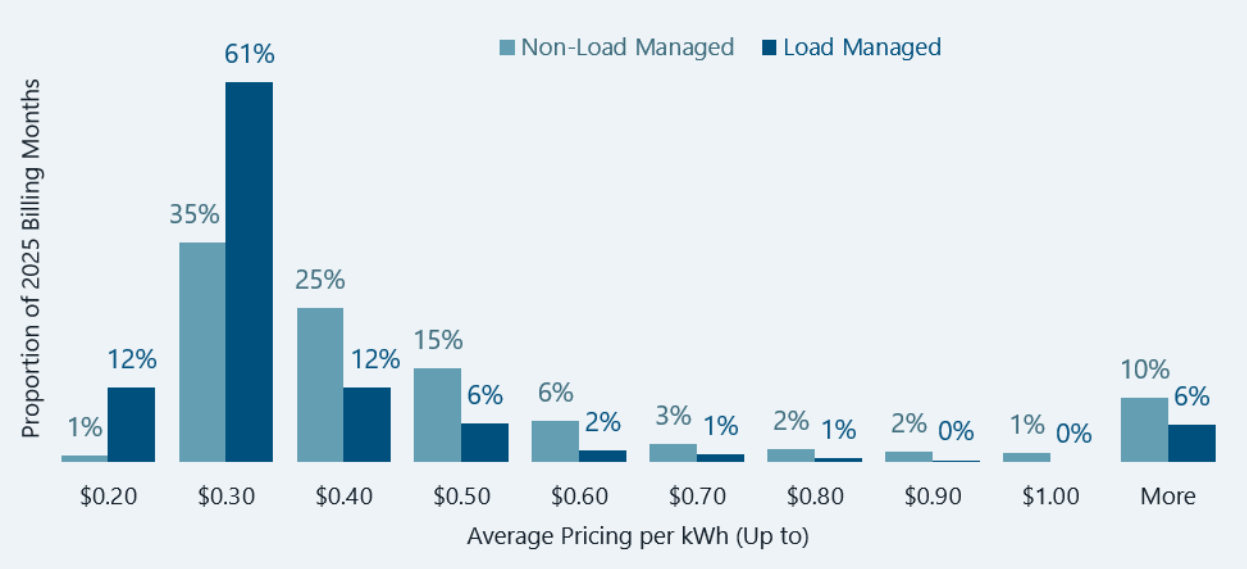


Figure 43 shows the distribution of average monthly billing costs per kilowatt-hour for all MDHD sites and market sectors. The lowest-cost sites show monthly billing between $0.20/kWh and $0.28/kWh through load management to avoid high-cost TOU rates (i.e., avoiding charging from 4 p.m. to 9 p.m.).

Figure 43. Distribution of Average Monthly Electricity Costs per Kilowatt-Hour, for Load-Managed and Non-Load-Managed Sites



Highlights

- Through 40 fleet manager interviews in the Load Management Deep Dives, the Evaluation Team identified two factors responsible for low uptake of load management. First, because fleet managers are not often responsible for monitoring or paying utility bills, many are unaware of the fleet's energy usage and utility bills, the relationship between the two, and the potential to lower their bills. Second, few NSPs provide load management software to fleets, and even fewer provide consistent customer support to help fleets. Because fleets sign multiyear contracts with NSPs, some fleet managers lack the leverage needed to obtain the information and support they need to implement load management.
- Installed capacity varies by market sector, with heavy-duty vehicle sites having the largest average capacity of 2.1 MW per site.
- Medium-duty vehicle and heavy-duty vehicle sites have the highest energy consumption (kWh) in EY2025, while heavy-duty vehicle sites have the highest demand (kW).
- Approximately 50% to 80% of all charging sessions overlap with the highest cost 4 p.m. to 9 p.m. charging period. Most fleets have charging flexibility to shift load. Transit bus and heavy-duty vehicle sites have the least flexibility of all market sectors, with the ability to shift approximately 20% of their energy.
- Fleets have the potential to use the batteries in their EVs to help manage load. The Evaluation Team estimates that MDHD vehicles in the Utility programs have an average daily battery usage of about 50%. This suggests that for at least some days some of these vehicles have excess battery capacity that can be used for load management.
- Over half of load-managed sites pay effective utility bills less than $0.30/kWh, while only 35% of non-load-managed sites achieve this bill rate. The lowest cost per kilowatt-hour of sites is approximately $0.15/kWh, and the highest costs sites pay above $1.00/kWh in certain months.

3.6. Utility Billing and GHG Savings Potential

3.6.1. Optimization Analysis of GHG Emissions and Utility Bills

This section examines the extent to which load management could decrease emissions and electricity costs. Very few NSPs participating in MDHD programs are effectively providing load management to fleets. Table 21 shows that 8% to 21% of MDHD sites appear to use load management in individual Utility programs, with a combined average of 18% for all MDHD sites.

Table 21. PTD Sites Exhibiting Use of Load Management in 2025

Utility	Total Sites	Sites Exhibiting Load Management	Load Management Percentage
SCE	115	21	18%
PG&E	157	33	21%
SDG&E	37	3	8%
Total	309	57	18%

All three utilities offer significantly lower TOU energy costs outside of the 4 p.m. to 9 p.m. peak TOU period than the on-peak energy rate, as shown in Figure 44. SCE and PG&E have aligned their tariffs to include a midday Super Off Peak (lowest-cost) period to encourage more energy use during the lower-demand, lower-emissions midday period. However, only SCE drops the midday price significantly (by approximately 50%, during winter weekdays) relative to other off-peak hours. PG&E offers only a small reduction (less than 15%) from 9 a.m. to 2 p.m. SDG&E continues to designate midnight to 6 a.m. for least-cost energy (Super Off Peak) and applies a slight cost increase over Super Off Peak pricing (approximately 10%) during the midday Off Peak period.[42] Larger midday cost drops by PG&E and SDG&E would create a stronger price signal for fleets to charge their vehicles more at that time and to reduce charging after 9 p.m.

[42] See pricing plans at www.sdge.com/residential/pricing-plans/about-our-pricing-plans/whenmatters

Figure 44. EV Rate TOU Pricing

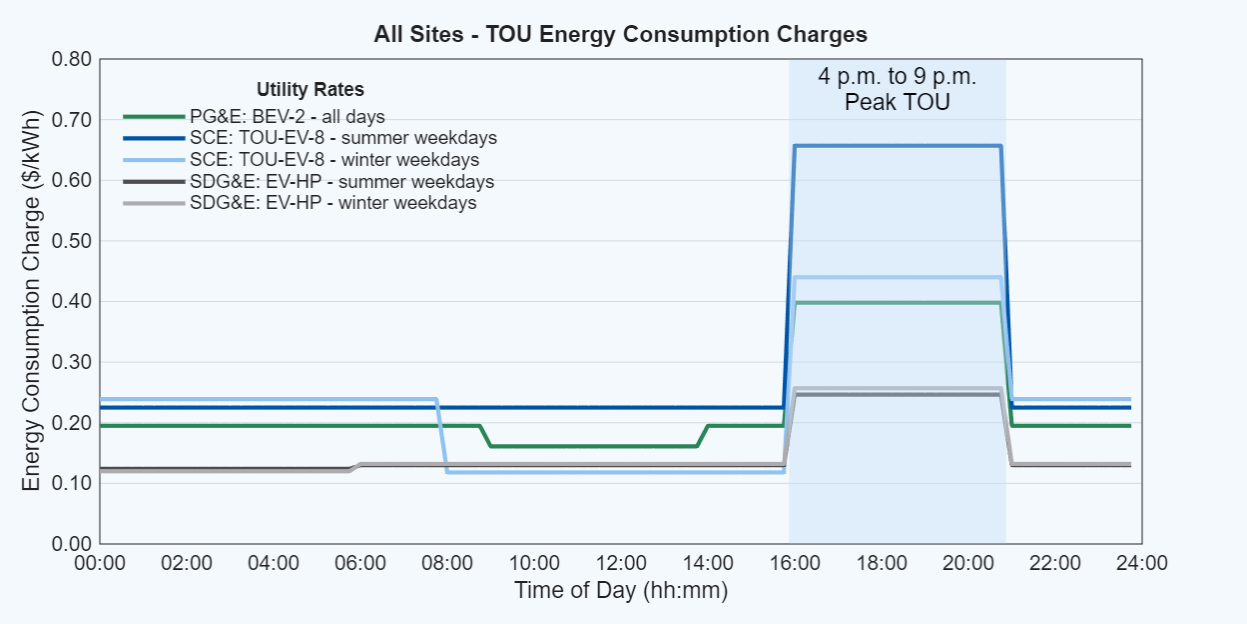
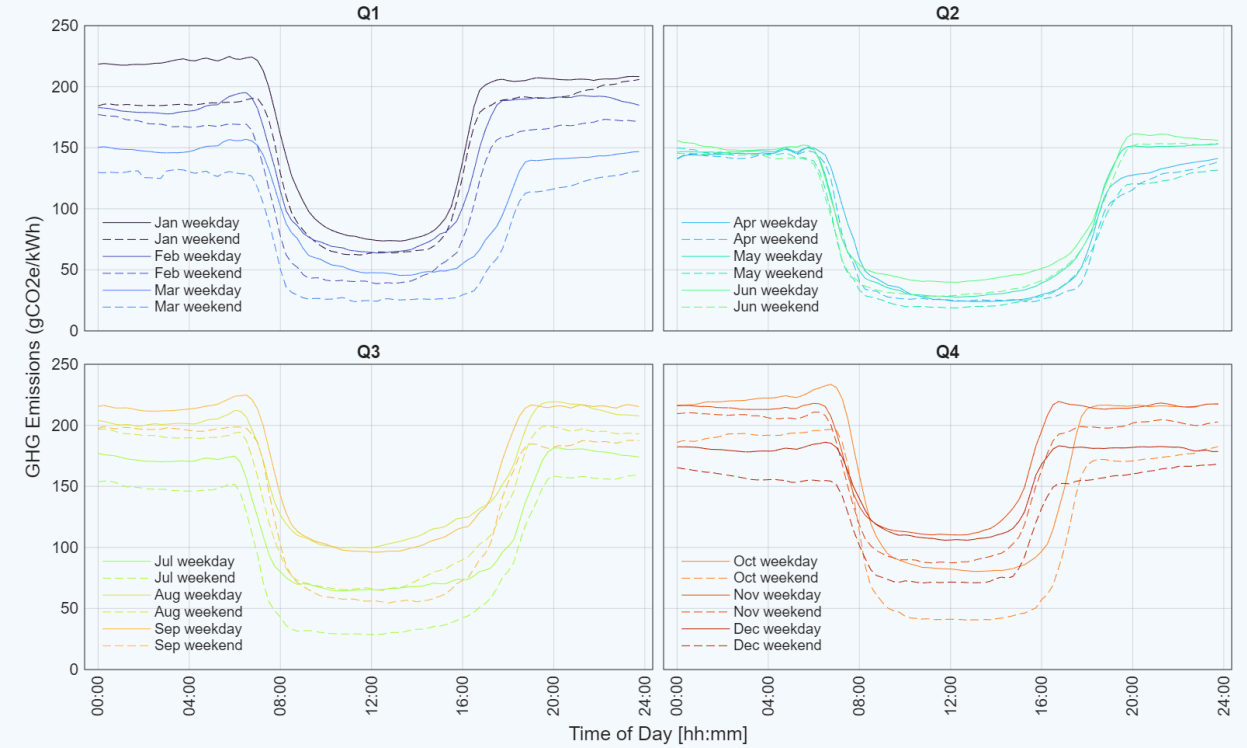


Figure 45 characterizes the variability in California's 2025 average electricity emissions at 15-minute intervals aggregated across weekdays and weekend days each month, using data from the California Independent System Operator (CAISO). In 2025, average daily emissions were generally lowest from 9 a.m. to 4 p.m. and generally highest between 7 p.m. and 7 a.m. Evening grid electricity generally produces two to four times the midday emissions, depending on the time of year.

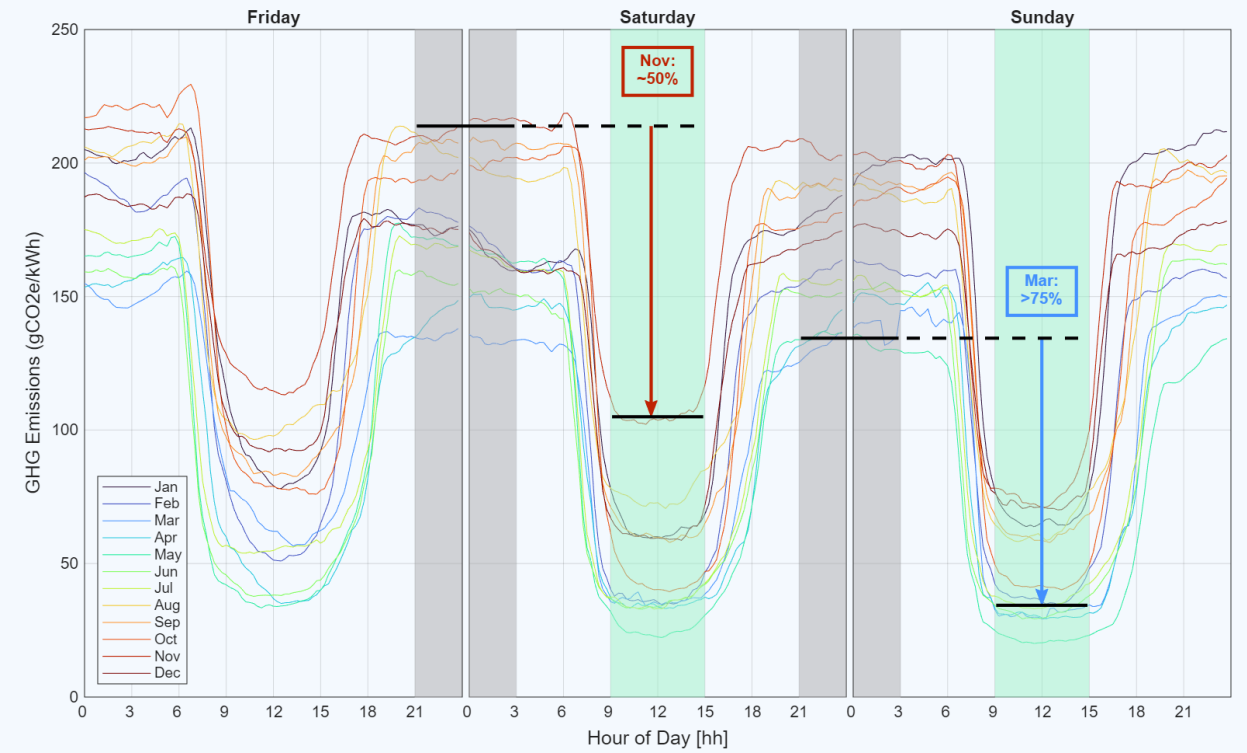
As can be seen in Figure 45, weekend days in the first, third, and fourth quarters of 2025 offered midday energy that often produced 20% to 30% lower emissions than weekdays. (Second-quarter emissions did not differ drastically between weekdays and weekends). Many fleets' Monday through Friday operations have charging flexibility that would allow them to delay charging operations from the highest-emissions period (directly after 7 p.m.) and highest-cost period (4 p.m. to 9 p.m.) to midday periods. In addition, slower or delayed charging on Friday evenings would allow them to shift consumption to lower emissions Saturday mornings.

Figure 45. 2025 Weekday and Weekend Average CAISO GHG Emissions by Month



In summary, fleets that typically charge at night can avoid over 60% of associated emissions by charging midday. The most prominent potential for charging emissions reductions is for operators to delay their end-of-week charging event into the weekend. For instance, fleets operating five days per week (such as most school fleets) could delay charging on Friday night until Saturday midday, and six-day operators could delay charging on Saturday night until Sunday midday. Figure 46 demonstrates how shifting a six-hour overnight charging window (9 p.m. to 3 a.m.) by 12 hours into the following day (9 a.m. to 3 p.m.) can lower the carbon intensity of grid emissions by 50% to 75%, depending on the time of year.

Figure 46. 2025 Weekend Average CAISO GHG Emissions by Month



The following section reviews the results of two models to investigate the extent to which fleets can reorganize their energy usage to reduce either site-level Utility bills or average electricity emissions attributable to EV charging. Figure 47 displays the business-as-usual (BAU) average load curve for each charging site in the four largest market sectors across all Utilities (lighter colored lines) based off historical charging behavior. The figure also displays the weighted-average load curve aggregated across each market sector (darker color line), illustrating overall charging behavior and the extent to which charging occurs during the highest-cost period (4 p.m. to 9 p.m.).

Figure 47. BAU (Historical) Aggregate Load Curves by Market Sector

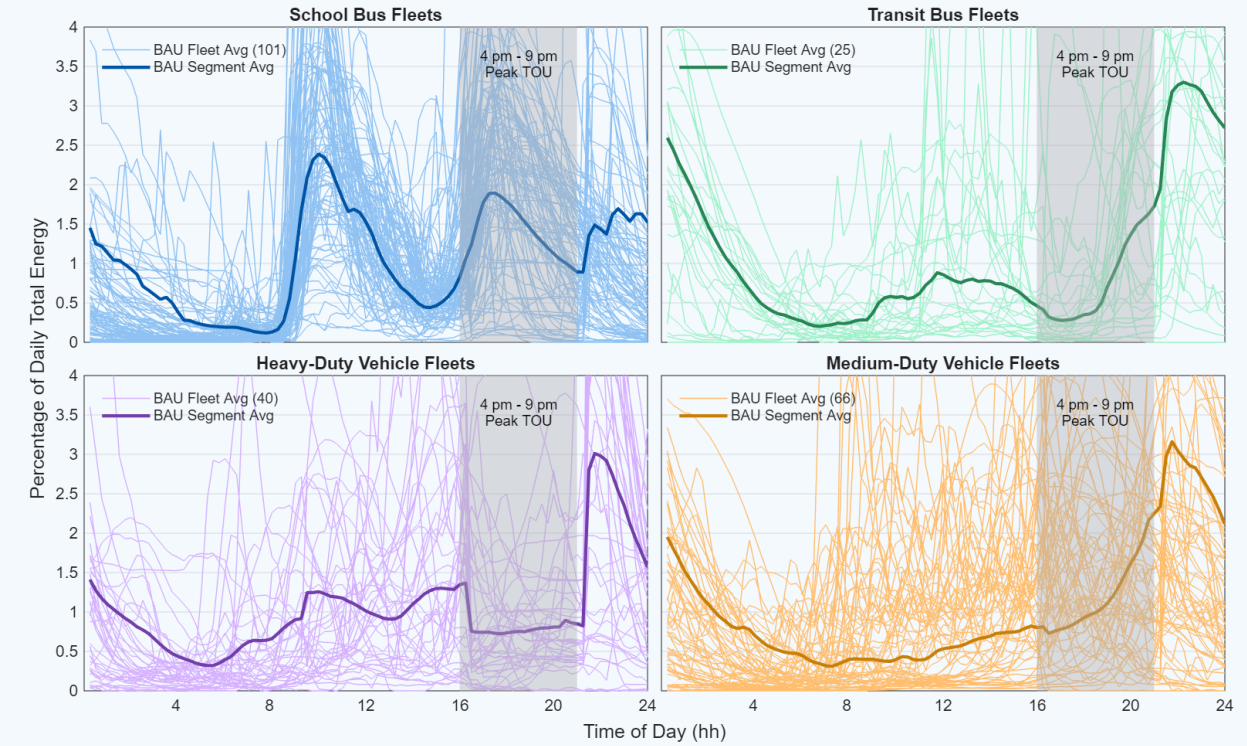


Figure 48 highlights BAU aggregate load curves for the four largest market sectors, as well as the shifted load curves for the cost-minimized and emissions-minimized cases from the load management optimization, to demonstrate the potential improvement over the BAU case.

The cost-minimizing (cost-min.) curve shows that most fleets could have avoided using nearly all of their historical energy usage from 4 p.m. to 9 p.m. In particular, school bus fleets could have increased midday charging and delayed afternoon charging events until after 9 p.m. to reduce costs. Results of the emissions-optimized case (GHG-min.) are similar in terms of maximizing midday charging whenever possible, and in the case of electric school buses that charge twice per day, charging to less than full in the evenings, though conflicts appear when low emissions intersect with high energy prices (e.g., from 4 p.m. to 6 p.m.). In general, shifting charging from evening to midday reduces emissions. Fleets opting into LCFS's Smart Charging approach can use this analysis to increase their credit generation and revenue.

Figure 48. Potential of Shifting Energy Usage to Reduce Electricity-GHGs and Utility Costs

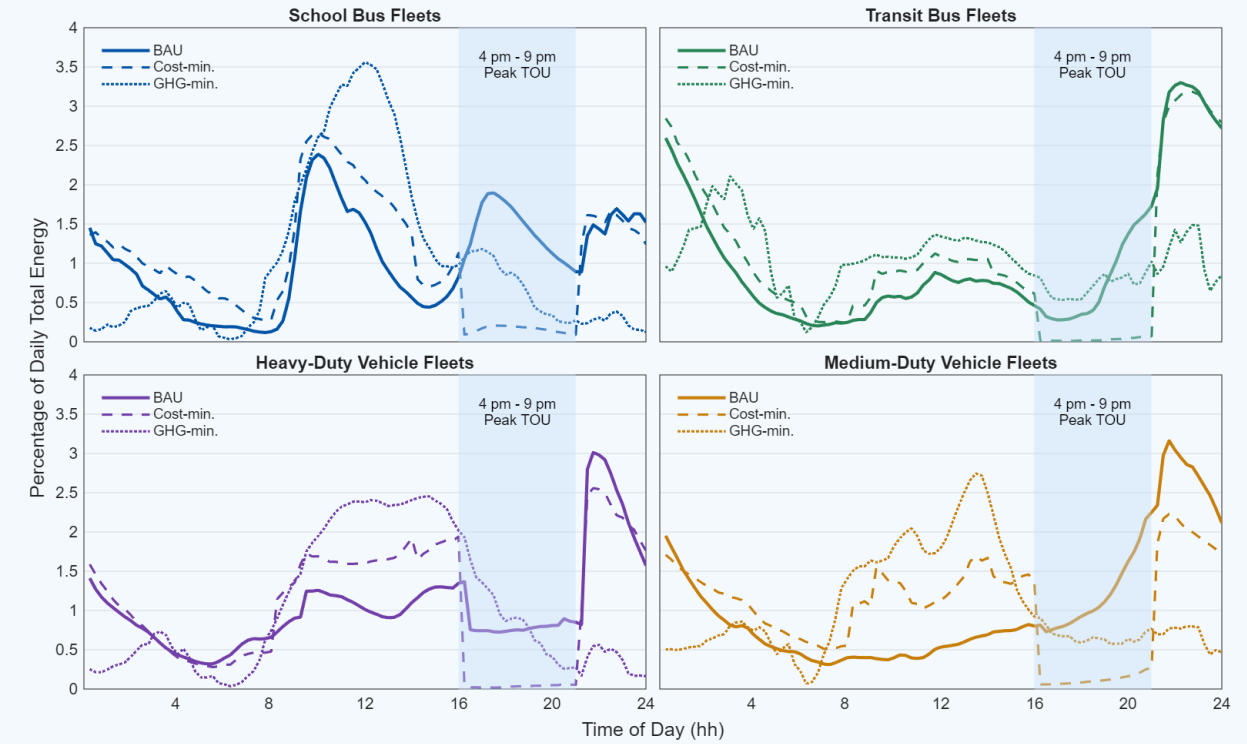


Figure 49 shows annual cost reduction potential on an individual site basis, both in terms of dollars (top row) and proportional savings (bottom row). Each bar represents one site, and the bars are ordered from high to low potential savings. Fleets in the medium-duty vehicle and heavy-duty vehicle market sectors show the greatest potential for actual dollar savings due to their higher total charging energy consumption. Half of the school bus sites could realize annual savings of more than $5,000, and approximately one-third could achieve savings of over $10,000. In many cases, sites identified as using load management have load curves that are surprisingly similar to those of sites without load management. One explanation for this is that while load-managed sites show consistent usage, they may have used load management for only part of 2025. The modeling shows that 65% of operators across these four market sectors could save 20% or more annually, while nearly 40% could save over 30% annually. A significant opportunity exists for vehicle operators to reduce the operating costs for their EV fleets early in their vehicles' lifetime.

Figure 49. Available Annual Dollar and Proportional Utility Bill Savings Modeling



Each bar represents one site. Bar colors indicate the site's market sector, and bar shades show its use of load management.

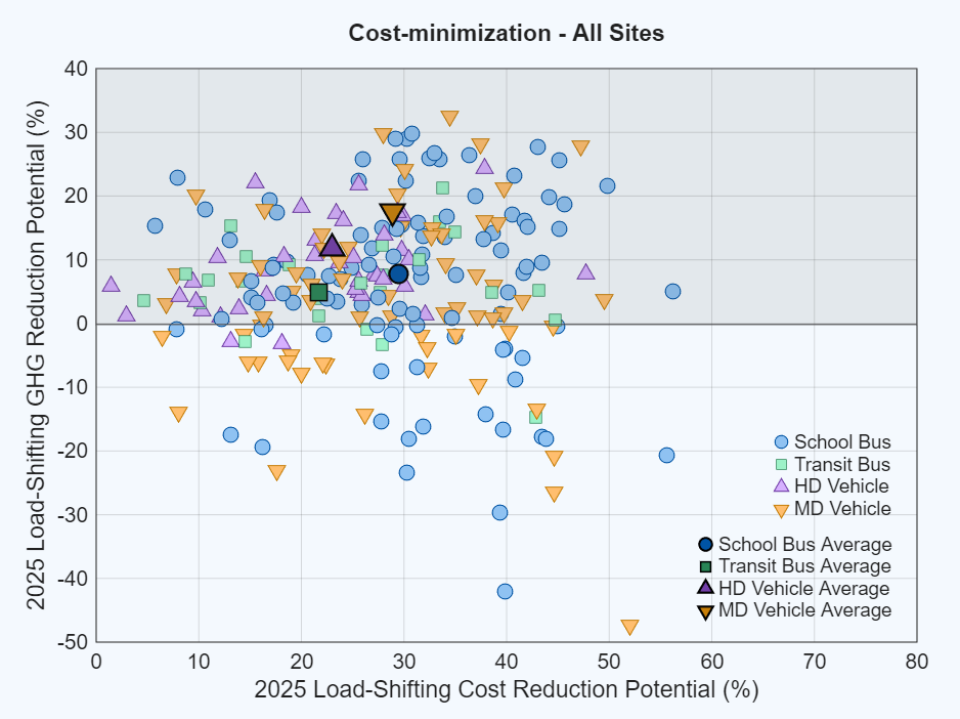
The Evaluation Team performed separate optimization modeling to quantify the extent to which shifting charging loads could minimize Utility costs (Cost-minimization) and electricity emissions attributable to EV charging (GHG-minimization) for every site. Figure 50 presents results from cost-minimization optimization, and Figure 51 presents results from GHG-minimization optimization, grouped by market sector. Each chart shows the tradeoffs for the other variable (i.e., the emissions impacts of minimizing costs and the cost impacts of minimizing emissions), and each axis depicts achievable results for each goal (emissions or costs). The *Grid Impacts* section for each Utility provides more detail about the tradeoffs when optimizing for either variable.

In general, cost and emissions co-benefits are achievable: decreases in emissions coincide with reductions in costs. A notable exception occurs at sites in the SDG&E service territory, where the lowest costs occur in the evening when overall grid demand is low and grid emissions are high. This rate structure means that SDG&E sites have not been positioned to fully realize the co-benefits of reduced costs and reduced

emissions.[43] As fleets become aware of this change and employ NSPs capable of load management, the Team expects further alignment of reduced costs and emissions in that service territory.

While many sites could see a 20% to 40% reduction in costs through cost-optimized load shifting, a small but significant number would also see an increase in emissions. Even so, charging flexibility shows significant opportunity to reduce both emissions and costs with current tariffs. This may further indicate that tariff design or demand response program strategies could significantly influence how EV fleets operate. As an example, a program could use day-before or day-of communication to encourage fleets to avoid energy consumption from 4 p.m. to 9 p.m. by increasing charging midday.

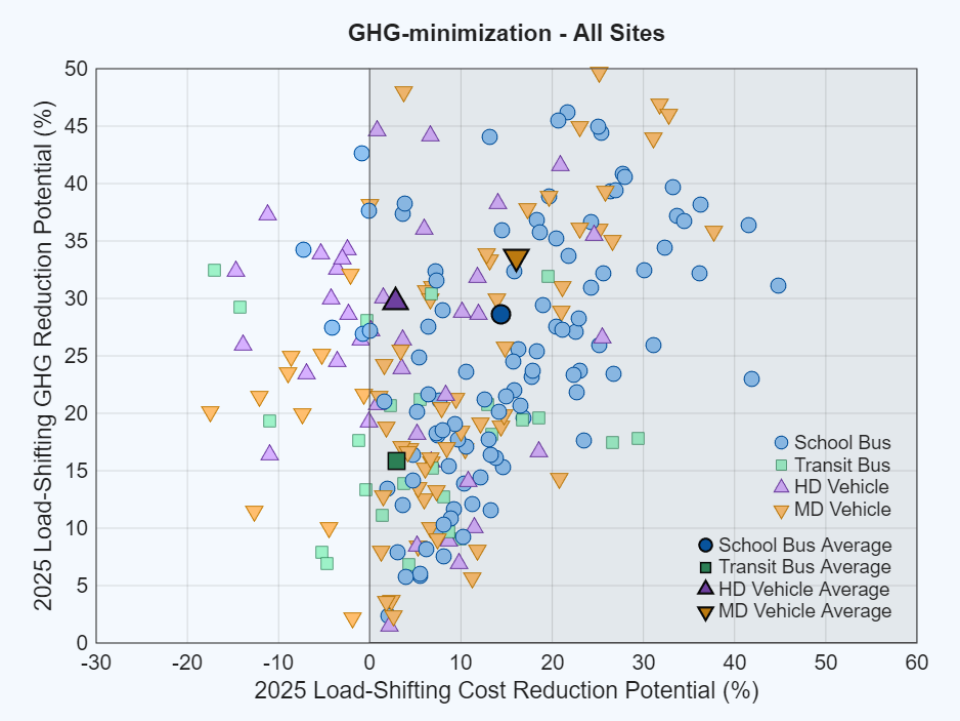
Figure 50. Results of Available Annual Improvements When Modeling for Utility Costs by Market Sector



The shaded box indicates the positive region for the x-axis and y-axis, highlighting sites with potential for both cost savings and GHG emissions reduction, under the cost-minimization scenario

[43] In 2025, the CPUC issued D.25-09-006 (A.23-01-008) in the SDG&E General Rate Case Phase 2, Cost Allocation and Rate Design proceeding, allowing SDG&E to include midday as a year-round Super Off-Peak period (10 a.m. to 2 p.m.).

Figure 51. Results of Available Annual Improvements When Modeling for GHG Emissions by Market Sector



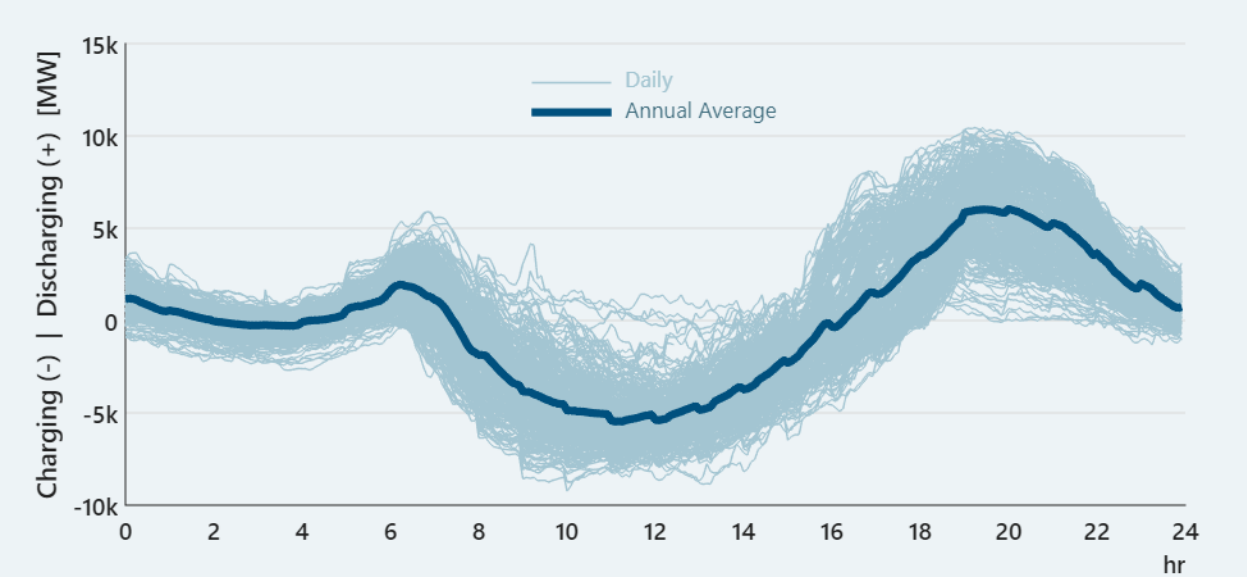
The shaded box indicates the positive region for the x-axis and y-axis, highlighting sites with potential for both cost reduction and GHG emissions reduction, under the GHG-minimization scenario

Over the programs' lifetime, California has increased its use of grid-scale batteries. Figure 52 depicts daily load curves of the overall battery market reporting into CAISO throughout 2025. The figure shows that these batteries are typically discharged to the grid from approximately 6 p.m. to 7 a.m. and primarily consume energy from the grid during the day between 8 a.m. and 4 p.m.

The period of consumption to recharge grid-scale batteries aligns with the period of lowest-cost energy and with weekday morning charging for school buses. This discharge and recharge cycle would be replicable on the weekends for most fleets that operate only Monday through Friday, as vehicles would remain dormant over the weekend and would not need to charge.

Our analysis indicates that batteries may provide value to fleets in the future. However, batteries send the most power to the grid in the evenings when many fleets that have not implemented load management charge unnecessarily, which could reduce the benefits of including batteries in fleet operations. Fleets deploying battery storage will need to effectively manage charging load to maximize financial savings, emissions reduction, and operational benefits.

Figure 52. 2025 Daily Energy Storage Trends by Time of Day



Best practices would suggest reducing the amount of battery-to-battery energy transfer when possible. As vehicle charging transitions from evenings (on peak or later), the renewable energy that grid-scale batteries consumed during this time can be used for non-transportation needs that have less flexibility. With this approach vehicles can increase charging midday throughout the week with renewable energy. The amount of energy grid-scale batteries take from or provide to the grid (approximately 10,000 MW and 50,000 MWh) is orders of magnitude higher than the 40 MW and 400 MWh these portfolios' vehicle charging approaches on a daily basis. Both EV charging and grid-scale batteries are still nascent technologies and will likely achieve synergies when fleets and private EV drivers receive adequate messaging to initiate load management.

Highlights

- 10% to 20% of MDHD program sites appear to use load management in individual Utility programs, with a combined average of 18% for all MDHD sites.
- Because the emissions intensity of the California grid decreases in the middle of the day with greater solar penetration, MDHD sites could reduce emissions at the end of the week by delaying charging until mid-day on Saturday or Sunday. For example, shifting a six-hour overnight charging window (9 p.m. to 3 a.m.) by 12 hours into the following day (9 a.m. to 3 p.m.) can lower the carbon intensity of grid emissions by 50% to 75%, depending on the time of year.
- Fleets in the medium-duty vehicle and heavy-duty vehicle market sectors show the greatest potential for actual dollar savings from better load management due to their higher total charging energy consumption.
- Half of the school bus sites could realize annual savings of more than $5,000 from better load management, and approximately one-third could achieve savings of over $10,000.
- When vehicles, hardware, software, and load management are properly aligned, fleets can reduce upwards of 90% of demand and consumption during the high-demand 4 p.m. to 9 p.m. peak period and significantly mitigate maximum demand at any time of day while maintaining operational readiness.

3.7. Petroleum Displacement and GHG Emissions Impacts

Table 22 shows the annual petroleum displacement and GHG emissions reductions associated with counterfactual vehicles that were replaced by EVs supported by charging infrastructure deployed under the Utilities' MDHD programs. Annual values per vehicle are based on the total reduction and total number of EVs observed during site visits or expected at each site.

The heavy-duty vehicle market sector shows the largest annual petroleum displacement and total annual GHG emissions reductions, but the transit bus market sector shows nearly the same annual petroleum displacement reductions per vehicle and annual GHG emissions reductions about 25% lower per vehicle. After the heavy-duty vehicle and transit bus market sectors, the medium-duty vehicle market sector has the next largest annual petroleum displacement, for both the total and per vehicle. However, the school bus market sector has higher annual GHG emissions reductions per vehicle.

Table 22. 2025 Annualized Petroleum Displacement and GHG Emissions Reductions by Market Sector

Market Sectors	Annual Petroleum Displacement (gallons)	Annual CO_2e Reduction (MT)	Estimated Observed EVs [a]	Annual Petroleum Displacement per Vehicle (gallons)	Annual CO_2e Reduction per Vehicle (MT)
Heavy-Duty Vehicle	3,870,057	31,611	978	3,957	32.3
Medium-Duty Vehicle	1,891,686	15,053	1,644	1,151	9.2
School Bus	1,105,188	9,464	965	1,145	9.8
Transit Bus	1,189,333	7,558	300	3,964	25.2

[a] Estimates are based on vehicles observed on site and other charging data analysis.

Figure 53 shows average petroleum displacement per vehicle by market sector, and Figure 54 shows average GHG emissions per vehicle by market sector.

Figure 53. Average Petroleum Displacement per Vehicle by Market Sector

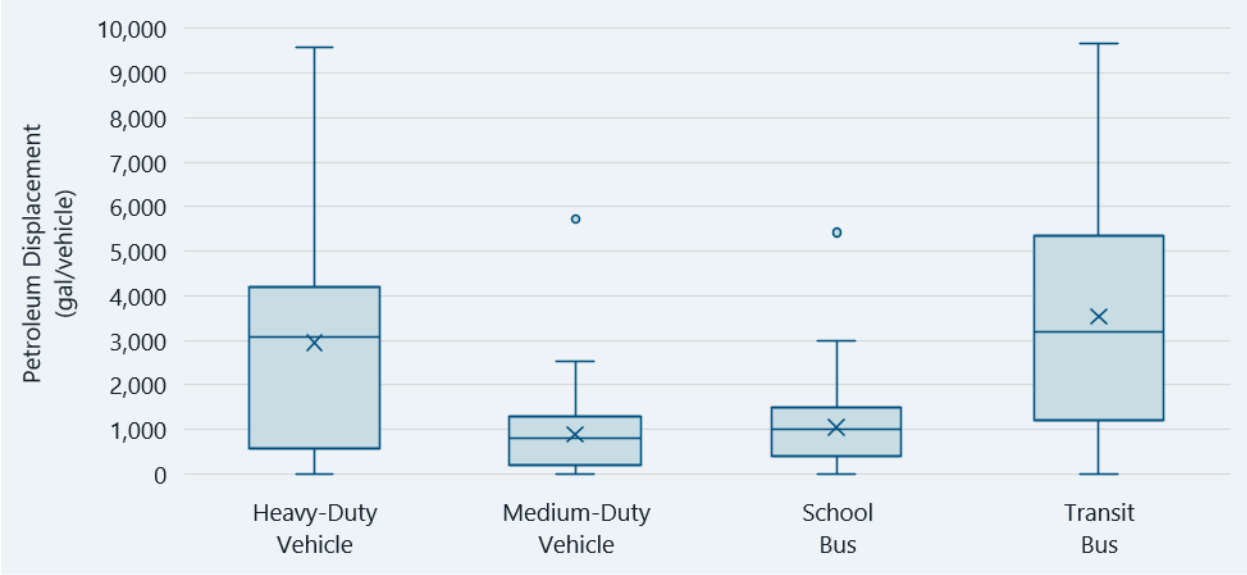


Figure 54. Average GHG Emissions Reduction per Vehicle by Market Sector

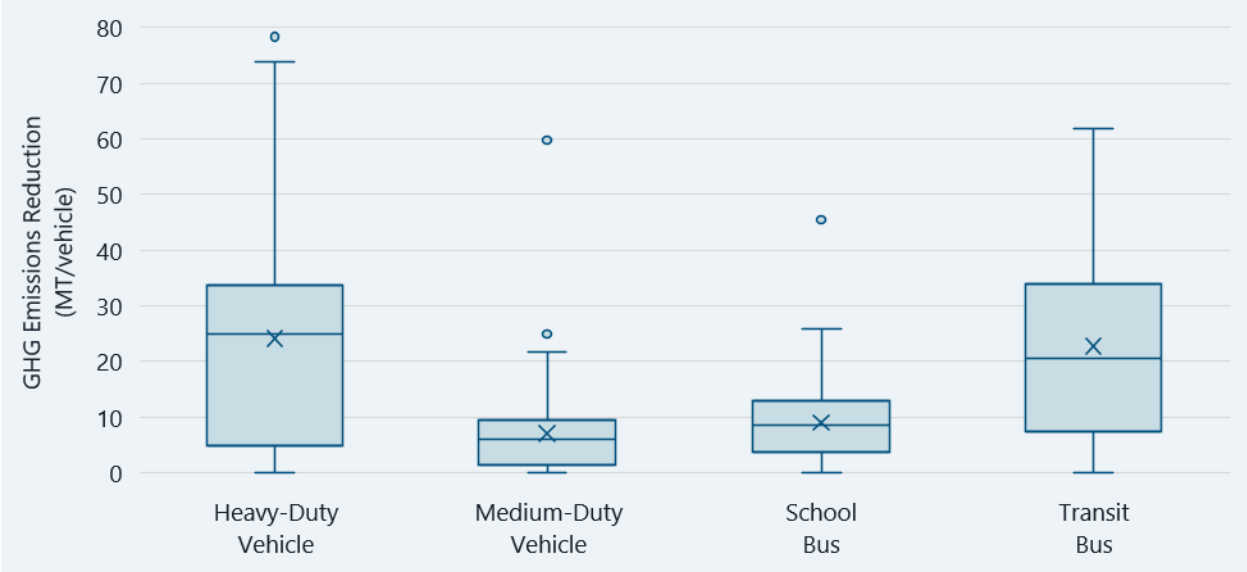


Figure 55 shows the annual program net electricity generation mix during the hours when the EVs were charging. The CAISO grid mix continually changes based on factors such as total grid demand and the availability of fossil generation and variable renewable resources such as solar. Based on the real-time grid conditions when the charging occurred, the overall energy mix was about 52% zero-emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 34% natural gas. Increased use of managed charging can reduce emissions as EVs charge at off-peak times

when the grid relies more on renewable energy. The following section discusses the potential for fleets to further reduce GHG emissions by shifting their charging times and rates.

Figure 55. Electricity Mix



Highlights

- Petroleum displacement and emission reductions are correlated with consumption behavior and vehicle efficiency, with heavy-duty vehicles showing the highest total reductions.
- The transit bus market sector has similar per-vehicle petroleum displacement and GHG emissions reductions as the heavy-duty vehicle market sector.

3.8. Fleet Manager Net-to-Gross Analysis

The Evaluation Team based our approach for the MDHD programs enhanced self-report NTG analysis on information we obtained as part of in-depth surveys with participating fleet managers. The Team created the survey via an online survey platform, Qualtrics, and provided a link to the survey during or following site visits that the Team conducted. As part of the net impacts analysis, the Evaluation Team estimated program effects on participants to exclude impacts from actions that participants would have taken without the program (freeridership) and to include any program-attributable indirect impacts on participants (participant spillover). Table 23 shows the estimated NTG ratios by market sector, along with the overall average fleet manager NTG ratio of 0.52 for all sites surveyed. The higher the NTG ratio, the higher the level of influence the programs had over fleet manager decision-making. In our analysis, the medium-duty vehicle market sector has the highest NTG ratio at 0.59, and the transit bus market sector has the lowest estimated NTG ratio at 0.42.

Table 23. MDHD Fleet Manager NTG Analysis Results for PTD Sites Surveyed

Market Sector	Responding Sites	NTG
Heavy-Duty Vehicle	13	0.46
Medium-Duty Vehicle	9	0.59
School Bus	30	0.57
Transit Bus	12	0.42
Overall	64	0.52

Highlights

- The average fleet manager NTG ratio of 0.52 for all sites 64 fleet managers surveyed.
- The medium-duty vehicle market sector has the highest NTG ratio at 0.59, and the transit bus market sector has the lowest estimated NTG ratio at 0.42.

3.9. Truck Choice Model

The Evaluation Team employed the UC Davis TCM[44] to understand future adoption scenarios of MDHD EVs in California. The TCM mimics fleet manager decision-making on fuel choices using a generalized cost equation that accounts for all real and perceived costs associated with vehicles and fueling infrastructure for diesel, compressed natural gas (CNG), electric, and hydrogen options.[45] The model has been used by UC Davis since 2017 to explain how California policies and programs impact fleet operator decisions involving the purchase of alternative-fuel MDHD vehicles.

The Evaluation Team used the TCM to predict sales shares for new EVs in six market sectors (Figure 56). The TCM uses slightly different market sector categories than the CPUC defined market sectors. New EV sales shares refer to the fraction of vehicle sales that are EVs. The Team ran the model for five scenarios defined in Table 24 for both 2030 and 2035. Each scenario varies the level of incentive provided to the fleet manager for the BTM infrastructure. As shown in the *Site Costs* section above, BTM costs vary by installed kilowatts and are a similar magnitude to TTM costs.

Table 24. BTM Incentives for Five Scenarios

ID	Scenario	Scenario Description
1	BTM Incentive 0%	Utilities do not provide a BTM incentive. The BTM cost is covered entirely by the fleet.
2	BTM Incentive 25%	Utilities pay 25% of the BTM cost and the fleet pays 75% of the BTM cost.
3	BTM Incentive 50%	Utilities pay 50% of the BTM cost and the fleet pays 50% of the BTM cost.
4	BTM Incentive 75%	Utilities pay 75% of the BTM cost and the fleet pays 25% of the BTM cost.
5	BTM Incentive 100%	Utilities pay 100% of the BTM cost and the fleet pays 0% of the BTM cost.

In 2025 the TCM incorporated historical sales data from the CEC Medium- and Heavy-Duty Zero-Emission Vehicles in California dashboard.[46] This data includes the sales of transit buses, school buses, tractor trucks (dominated by short-haul), and medium-duty delivery trucks. Sales of TRUs and port cargo trucks were not available in the CEC dashboard. The Evaluation Team used the 2025 sales of vehicles in these market sectors to calibrate the TCM's projections.

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44 Miller, Marshall, Qian Wang, and Lew Fulton. November 2017. National Center for Sustainable Transportation Research Report: Truck Choice Modeling: Understanding California's Transition to Zero-Emission Vehicle Trucks, Research Report UCD-ITS-RR-17-36, 2017.

45 Generalized cost is akin to TCO but also includes nonmonetary factors like risk.

46 California Energy Commission (2025). Medium- and Heavy-Duty Zero-Emission Vehicles in California. Data last updated December 31, 2025. Retrieved April 2026 from www.energy.ca.gov/zevstats

Figure 56. New EV Sales Share in Six Market Sectors



3.9.1. TCM Results Discussion

Overall, results from the TCM projections show the importance of BTM incentives. Results for the EY2025 report are similar to those of the EY2024 report, with the exception of market penetration projections for the school bus and transit bus market sectors, which were significantly higher in EY2025 than in EY2024. For each market sector, the sales share of EVs increases from Scenario 1 (0% BTM incentive) to Scenario 5 (100% BTM incentive). The percentage of the increase in sales ranges from 5.4% (TRU) to 26.3% (school bus) in 2030 and from 9.6% (TRU) to 25.4% (port cargo truck) in 2035. BTM incentives show a greater impact in 2035 than in 2030 because the incentive values remain the same while the difference decreases between diesel and EV vehicle costs.

The transit bus market sector is unusual in that lower sales are projected in 2035 than in 2030. Sales for transit bus ZEVs are projected to be roughly 100% in both 2030 and 2035, but projections show sales of fuel cell transit buses increasing between 2030 and 2035 causing the projections for market share of battery electric transit buses to decrease.

3.9.2. TCM Limitations

The TCM's market share projections are based on several inputs that could change significantly in the future. Inputs make use of technology cost projections, which are inherently uncertain. The section below discusses some of the critical inputs and how they may vary from those used in this analysis.

Clean Truck and Bus Voucher Incentive Project (HVIP) Incentives

Presently, CARB allocates HVIP funding every year with the total amount varying.[47] Once ZEVs show significant market penetration, this funding may change. We have assumed that there will be enough funding allocated to meet the needs of all fleets purchasing ZEVs, but that outcome would require large increases in the total allocation. If those increases do not occur, funding could decrease or be eliminated.

Vehicle Costs

Projections of EV costs assume significant increases in sales volume to reduce component costs. Sales of LDVs are likely to increase at the projected rate, but sales of truck OEMs will likely not increase at a comparable rate. Projections for truck batteries could be optimistic, which would result in lower cost reductions than projected from 2030 to 2035.

Low Carbon Fuel Standard (LCFS) Program

The LCFS program lowers the effective electricity and hydrogen costs for fleets enrolled in the program. The LCFS credit price and the program target carbon intensities vary over time and determine the potential cost savings for the various fuels. The credit price could become higher or lower than assumed in this analysis. In April 2025, the LCFS credit price was over $150 per credit, but at the end of 2025 it had fallen to roughly $75 per credit. If the credit price is greater than assumed, electricity savings would

[47] HVIP is funded by CARB and administered by CALSTART.

increase from the projected savings, and a lower-than-assumed credit price would result in less savings than projected.

Advanced Clean Truck/Advanced Clean Fleet

CARB's ACT and ACF regulations aggressively mandate sales and purchases of zero-emission trucks and buses. Recently, California withdrew its application for a waiver for the ACF regulation, which removed the mandate on fleet purchases for some fleets. A recent Congressional Review Act resolution was enacted into law rescinding the waiver that allowed California to enforce the ACT regulation.[48] Without these regulations, the projected cost assumptions for vehicle technology and BTM would likely increase as OEMs deprioritize selling ZEVs.

Hydrogen Price and Availability

Currently, hydrogen fuel is available in limited locations. With few fuel cell electric vehicles (FCEVs) on the road, demand for hydrogen fuel is low, causing the price of hydrogen fuel to remain high. The lack of availability and the high price of the fuel disincentivize fleets from purchasing FCEVs. If these two barriers were reduced, FCEVs could better compete with EVs for market share, which would reduce the projected sales shares of EVs.

Highlights

- BTM incentives have a strong impact on the predicted new EV sales share across market sectors, although impacts vary.
- As an example of the impact of BTM incentives, the new EV sales share in the school bus market sector increases from 17% to 43% between the no-BTM incentive scenario and 100% BTM incentive scenario in 2030. By 2035, the school bus market sector increases from 57% to 81% across the two scenarios.

3.10. Natural Market Baseline

As described in the Introduction, a key objective of this evaluation is to measure the impact of the Utility programs on the broader transportation electrification market. To do this, the Evaluation Team needs to understand the natural market baseline—that is, the trajectory of EV adoption in the absence of the Utility programs. This baseline can be compared with the actual market share to understand Utility program impact. To develop this natural market baseline, the Evaluation Team conducted two Delphi surveys described below.

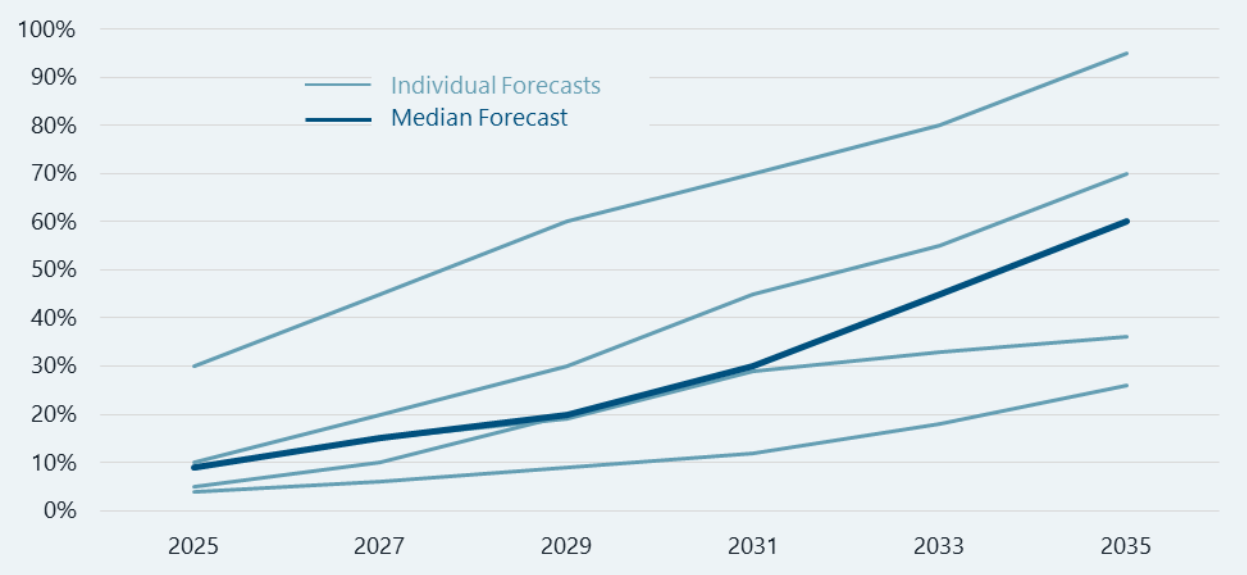
[48] H.J. Res. 87, "Joint Resolution providing congressional disapproval under chapter 8 of title 5, United States Code, of the rule submitted by the EPA relating to 'California State Motor Vehicle and Engine Pollution Control Standards; Heavy-Duty Vehicle and Engine Emission Warranty and Maintenance Provisions; ACT; Zero Emission Airport Shuttle; Zero-Emission Power Train Certification; Waiver of Preemption; Notice of Decision'"

3.10.1. Yard Truck Electrification Baseline Market Share

The Evaluation Team forecasted the baseline market share of electric yard trucks in California through vehicle model year 2035 using the Delphi method, which involved surveying a panel of subject-matter experts about future EV market adoption rates. The yard truck panel comprised five experts. After each round, the Evaluation Team presented panelists with anonymized results and gave them the opportunity to revise their responses. The goal of this iterative method is to reach a consensus or near-consensus forecast.

Figure 57 shows the individual adoption curves from the first round of surveys (Round 1) along with the median forecast. The baseline represents electrification in the absence of utility incentives. The horizontal axis indicates vehicle model year and applies to only new vehicles, not the entire statewide vehicle stock.

Figure 57. Delphi Panel Round 1 Electric Yard Truck Adoption Forecasts



Round 1 forecasts varied widely, reflecting substantial uncertainty in the pace of yard truck electrification. Estimates of electric market share in 2035 ranged from a low of 26% to a high of 95%, with a median forecast of 60%. In Round 2, three of the five panelists converged on the median trajectory, with one panelist resubmitting their original forecast and another not submitting a second-round response. Consistent with the Delphi methodology described in *Appendix B*, the Round 1 median became the final consensus forecast. The baseline consensus estimate indicates that 60% of new yard truck sales in California will be electric by 2035.

While the primary objective of the Delphi process is to produce a consensus forecast, panelists' supporting rationales provide important insights into the factors expected to influence yard truck electrification, namely infrastructure, policy, and economics.

Two of the five panelists identified policy and regulatory drivers as major factors shaping electric yard truck adoption. These panelists highlighted the role of regional policies and initiatives (including the San

Pedro Bay ports' goal of transitioning to zero-emission cargo handling equipment) and regulatory mechanisms (such as the South Coast Air Quality Management District's indirect source rule for warehouses). These policies are expected to drive early adoption of electric yard trucks in ports and large warehouse facilities. However, panelists also noted uncertainty about the timing and scope of broader statewide regulations, including potential actions by CARB, which contributed to variability in their long-term projections.

Two panelists each identified a key challenge to electric yard truck adoption: deploying charging infrastructure at scale and integrating charging schedules into operations. These panelists noted that yard truck electrification often requires significant facility upgrades that can take more than two years to plan and implement. Operational considerations also pose challenges: high-utilization facilities operating across multiple shifts may have limited downtime available for charging, constraining adoption, and improvements in battery capacity and charging speed will be needed to support widespread adoption.

Despite these issues, panelists highlighted strong underlying economic and operational considerations that support long-term electrification. Compared with their diesel counterparts, total cost of ownership (TCO) for electric yard trucks is lower because the EVs have lower maintenance requirements and offer operational efficiencies, particularly in low-speed, high-utilization duty cycles. Additional benefits such as reduced noise, improved driver experience, and alignment with corporate sustainability goals further enhance their attractiveness. Over time, panelists expect that these factors will support increasing adoption.

The panel's responses suggest that yard truck electrification in California will be driven by a combination of localized regulatory pressure, improving economics, and technological advancement, but will be constrained in the near term by infrastructure and operational limitations. Initial adoption is expected to be concentrated in large ports and warehouse facilities before expanding more broadly across the state.

Highlights

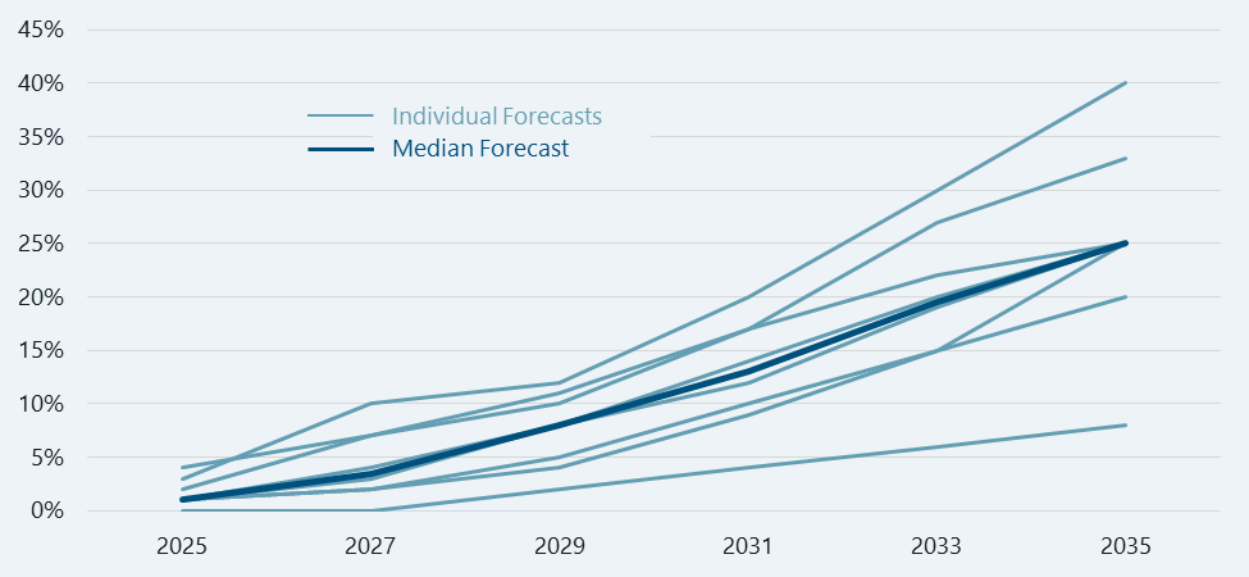
- The Delphi panel's baseline consensus forecast indicates that 60% of new yard trucks sold in California will be electric by 2035.
- Two of five panelists identified policy and regulatory drivers, particularly in ports and warehouse settings, as key catalysts for adoption, while one panelist highlighted infrastructure constraints and another emphasized funding limitations as major barriers.
- Panelists said that lower TCO than for diesel counterparts and operational benefits support long-term electric yard truck adoption, though near-term growth is constrained by infrastructure and operational limitations.

3.10.2. Regional and Long-Haul Tractor Truck Electrification Baseline Market Share Update

The Evaluation Team updated the baseline forecast for Class 7 and 8 electric regional and long-haul tractor trucks in California through vehicle model year 2035, following two rounds of responses from a Delphi panel. This baseline represents electrification in the absence of utility incentives and updates the consensus forecast developed as part of EY2023 Evaluation Report.[49] A panel of eight experts provided a first round of input, after which they were shown anonymized results and given the opportunity to revise their responses or agree with the median forecast.

Figure 58 shows the individual curves from the first round of input (Round 1), along with the median curve. The horizontal axis reflects vehicle model year and applies to only new vehicle sales, not the total statewide fleet.

Figure 58. Delphi Panel Round 1 Updated Electric Regional and Long-Haul Tractor Truck Adoption Forecasts



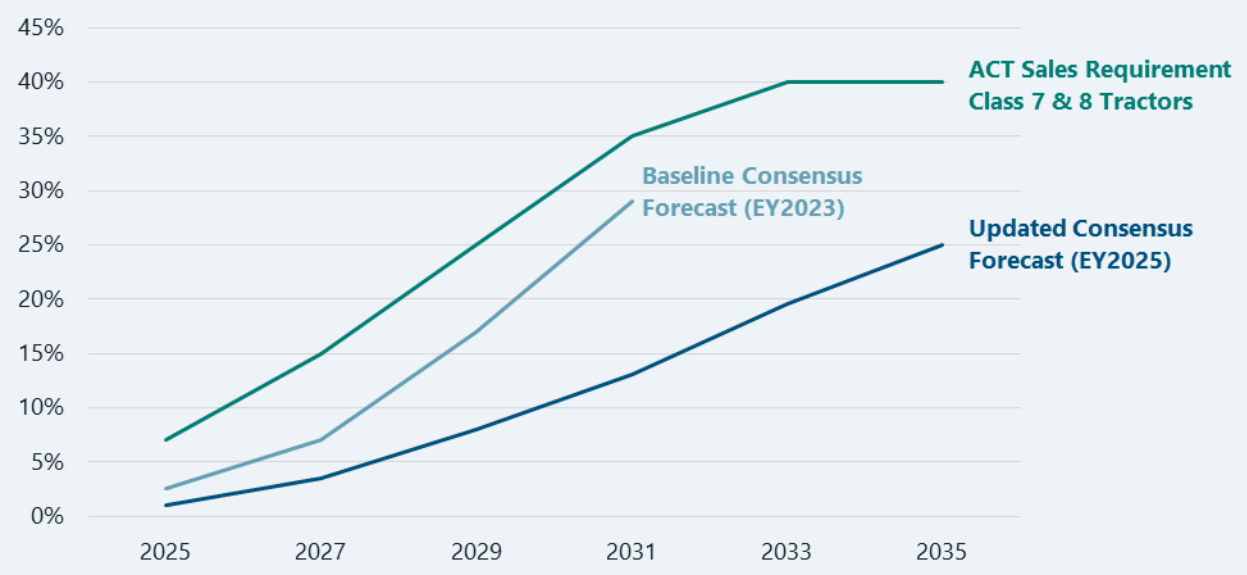
Round 1 market share forecasts for 2035 ranged from 8% to 40%, with a median forecast of 25%. In Round 2, six of the eight panelists submitted a response, with five agreeing with the median or consensus forecast, and one submitting a revised forecast (their original forecast). As described in *Appendix B*, the forecasting process iterates until a majority consensus is reached. As the majority of panelists agreed with the median forecast in Round 2, this forecast is considered to be the final consensus result. The updated

[49] Cadmus and Energetics. October 2024. *Standard Review Projects and AB 102/1083 Pilots Evaluation Year 2023 Third-Party Evaluation Report.* www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/sb-350-te/srp-ab10821083-2023-evaluation-report112024.pdf

baseline consensus forecast estimates that 25% of new tractor trucks sold in California will be electric by 2035.

Figure 59 compares the updated consensus forecast with the prior baseline forecast from the EY2023 Evaluation Report and displays the relevant sales schedules from the ACT regulation. The ACT regulation specifies when a certain percentage of all new vehicle sales in California must be ZEVs. The updated forecast is substantially lower than the earlier consensus forecast and falls farther below the ACT requirement of 40% zero-emission tractor truck sales by 2035. This gap suggests that under current market conditions and without utility incentives, tractor truck adoption may struggle to meet California's long-term electrification targets set by CARB.

Figure 59. Delphi Panel Electric Regional and Long-Haul Tractor Truck Updated Market Share Forecast



While the primary objective of the Delphi panel is to develop a consensus forecast, the panelists' rationales provide important context for interpreting these results. Across responses, panelists consistently described a more challenging outlook for tractor truck electrification compared with their prior expectations, driven by a combination of weakening policy support, persistent infrastructure barriers, and unresolved economic challenges.

Policy uncertainty emerged as the most frequently cited factor shaping the updated forecasts, representing a notable difference from the EY2023 panel, in which only one panelist identified policy as a constraint. Six of eight panelists cited delays or reversals in key state regulations, including uncertainty surrounding ACT enforcement and the anticipated repeal of ACF provisions, which have reduced pressure on fleets to transition to zero-emission trucks and therefore constitute a major factor slowing adoption. Two panelists suggested that the early sunset of incentives at the federal level, such as the IRA commercial vehicle tax credit, and broader uncertainty around federal funding is undermining the economic case for electric tractor trucks.

Six panelists cited fundamental economic and operational challenges associated with electrifying tractor trucks as key impediments to adoption, consistent with findings from the EY2023 panel. These panelists explained that longer refueling times and reduced payload capacity due to battery weight constitute real operational disadvantages for electric tractor truck operators. Three panelists further emphasized that achieving cost and performance parity with diesel trucks, particularly for long-haul applications, would likely require significant technological advances in battery chemistry, materials, and manufacturing that remain uncertain within the forecast timeframe.

Similar to the EY2023 panel, the majority of panelists in EY2025 indicated that infrastructure constraints are a critical barrier, particularly for applications beyond drayage and short-haul operations. These panelists emphasized that the buildout of high-capacity charging infrastructure remains slow and geographically uneven, with significant gaps along major freight corridors. Two of these panelists highlighted that, even where the infrastructure is available, charging logistics and downtime constraints limit operational feasibility.

Despite these challenges, panelists identified several factors that they expect to support gradual adoption. Panelists predict that electrification is likely to continue advancing in specific use cases, particularly in port and drayage operations in which duty cycles are predictable and vehicles can return to their depot for charging. These panelists stated that localized funding mechanisms, such as port-driven programs and continued support from California incentive programs such as HVIP, will help sustain adoption. Panelists also agreed that increased competition among manufacturers and the entry of new market participants, such as the Tesla Semi, will contribute to cost reductions, improving the business case for electrification in the long term.

Overall, the panel's responses indicate a more constrained and uncertain trajectory for tractor truck electrification than previously projected. While adoption is expected to grow steadily through 2035, it will likely remain below policy targets and be concentrated in specific applications without significant improvements in regulatory certainty, infrastructure deployment, and vehicle economics.

Highlights

- The Delphi panel's updated consensus forecast estimates that 25% of new tractor trucks sold in California will be electric by 2035, representing a significant downward revision from prior expectations.
- The panelists' forecast falls well below the ACT requirement of 40% by 2035, indicating that current market conditions are insufficient to meet state targets without additional support.
- Six of eight panelists cited policy uncertainty and regulatory weakening as the primary driver of slower adoption, while five of eight identified infrastructure limitations as a critical constraint.
- Panelists expect electrification to remain concentrated in drayage and localized applications, with broader adoption limited by economic and operational challenges.

4. Southern California Edison Transportation Electrification Programs

4.1. Charge Ready Transport Program

4.1.1. Overview

This overview provides a detailed description of the SCE Charge Ready Transport program; summaries of the program implementation process, performance metrics, materials, and budget; and a timeline of major milestones. Following the overview the Evaluation Team presents the 2025 findings, highlights, and lessons learned.

Program Description

Per Decision 18-05-040, SCE's Charge Ready Transport program provides infrastructure for fleet electrification at a low cost or no cost to participants who procure at least two medium- or heavy-duty (MDHD) EVs. SCE launched the Charge Ready Transport program in May of 2019 to accelerate the adoption of MDHD EVs by lowering the TCO for fleets, help businesses reduce emissions, and offer an avenue for customers to take advantage of current incentives. Charge Ready Transport has an approved budget of $342.6 million. Though the program originally targeted 870 sites supporting 8,490 EVs procured or converted to electric, the site goal was reduced in 2023 in Resolution E 5257 to 500 sites. Per Decision 22-11-040, approved November 17, 2022, the Charge Ready Transport program extended the application submission period through June 30, 2026, with a deadline for all agreements to be fully signed by December 31, 2026.

Charge Ready Transport Program Design Goal

Accelerate the adoption of MDHD EVs by lowering the TCO for fleets, assisting businesses in reducing emissions, and offering an avenue for customers to take advantage of current incentives.

Through the Charge Ready Transport program, SCE covers the cost of most or all of the distribution charging infrastructure up to the first point of connection with a participant's EVSE. Participants can choose Utility ownership or customer ownership of BTM infrastructure. If SCE owns both the Utility side and the customer side of the meter infrastructure, then SCE pays to design, construct, own, and maintain all infrastructure up to the EVSE, and the participant is responsible for the costs of installing and maintaining the EVSE. If the participant decides to own the BTM infrastructure, SCE will pay to design, construct, and maintain all TTM infrastructure, which the Utility will own. The participant will pay to design, construct, own, and maintain all BTM infrastructure and will receive a rebate for up to 80% of what it would have cost SCE to perform the BTM work or for the participant's actual installation

Original Program Target

Achieve a minimum of 870 sites with 8,490 MDHD EVs procured or converted.

Revised Program Target

Achieve a minimum of 500 sites with 8,490 MDHD EVs procured or converted.

costs, whichever amount is lower. Additional charger rebates are available for transit and school bus deployments and for fleets that are located in DACs and not operated by Fortune 1000 companies.

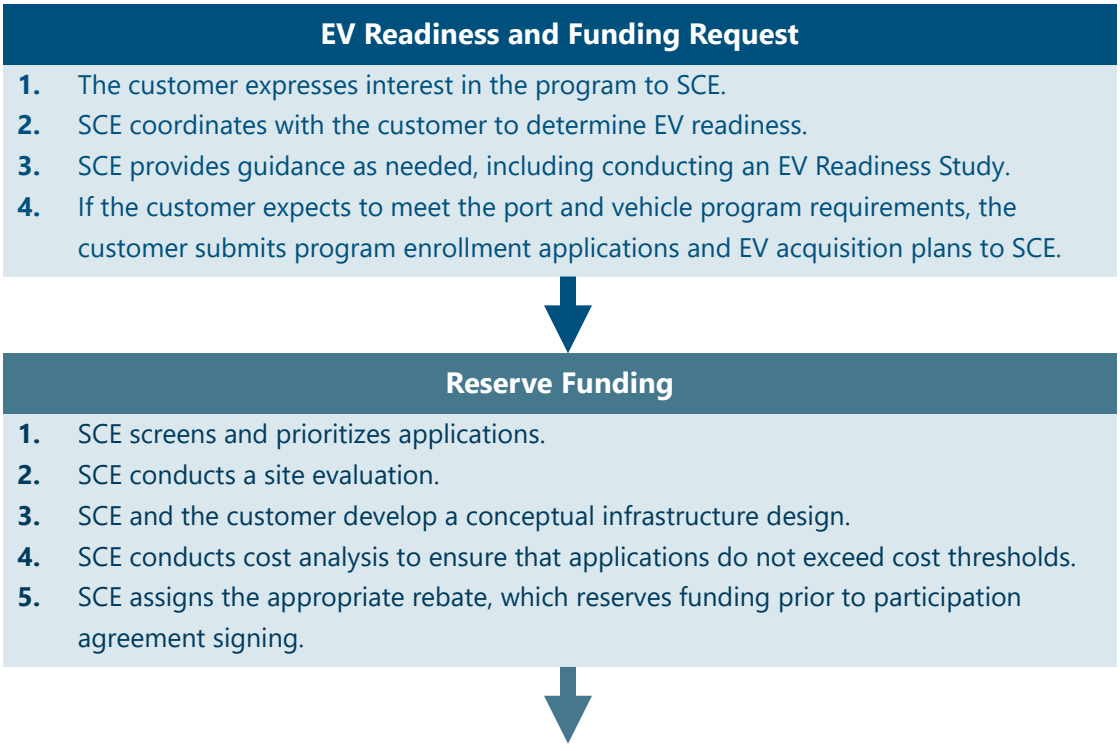
To participate in the Charge Ready Transport program, fleets must meet specific criteria. The program requires participating customers to lease or purchase at least two MDHD EVs, which are defined as Class 2 through Class 8 on-road and off-road vehicles, including MDHD trucks and vans, transit buses, commuter buses, school buses, TRUs, airport GSE, port equipment, forklifts, and other equipment, to augment or replace vehicles in the fleet. Fleets must also own or lease the site property, operate and maintain the charging infrastructure for 10 years, provide monthly data related to EV usage for five years, and use approved vendors for the EVSE, among other requirements. Pursuant to the SB 350 Decision, the Charge Ready Transport program's infrastructure budget should allocate a minimum of 15% for transit agencies, up to 10% for forklifts, and at least 25% for ports and warehouses in SCE's territory. A minimum of 40% of sites should be situated in DACs in SCE's territory.

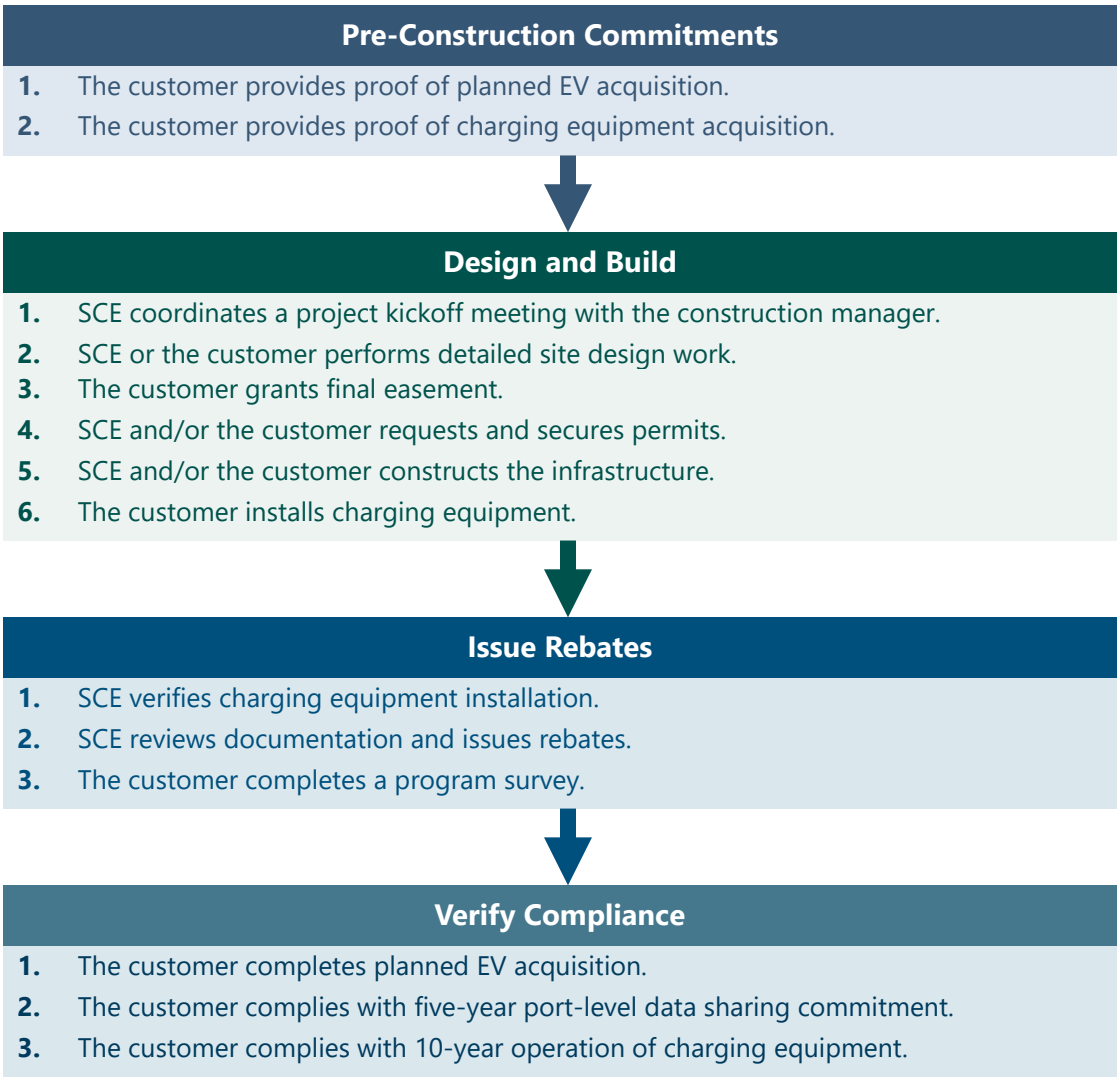
To support commercial EV fleet customers, SCE offers EV-specific TOU rates (TOU-EV-7, TOU-EV-8, and TOU-EV-9), which include demand charge relief. The specific charge paid by the customer includes a monthly fixed customer charge, an energy charge (per kilowatt-hour), and a demand charge, based on the highest recorded demand during each monthly billing period. In Decision 22-08-001, SCE received approval for an extension of the demand charge holiday for TOU-EV-8 and TOU-EV-9.

Implementation

Figure 60 details the key steps in the Charge Ready Transport program implementation process. There were no major changes to the implementation process in 2025.

Figure 60. SCE Charge Ready Transport Program Implementation Process





Program Performance Metrics

The Evaluation Team reviewed the participating sites in SCE's Charge Ready Transport program and organized them by program status. Table 25 displays the number of sites in the program by completion status as of December 31, 2025.

Table 25. SCE Charge Ready Transport Program Total Site Count by Status

Site Status	EY2025	Program to Date
Utility Construction Complete	33	132
Activated	29	115
Operational	29	115
Closed Out	21	76

In EY2025, the SCE Charge Ready Transport program received 63 applications, signed contracts with 45 sites, and activated 29 sites that supported 909 vehicles across five market sectors. This brought the total number of Charge Ready Transport program applications to 327 and the total number of executed

contracts to 260.[50] As shown in Table 26, 86% of sites activated in 2025 (25 of 29) and 72% of sites activated by the end of 2025 (83 of 115) are located within a DAC.

Table 26. SCE Charge Ready Transport Program Number of Activated Sites by Market Sector in EY2025 and Program to Date

Market Sector	EY2025		Program to Date	
	DAC	Non-DAC	DAC	Non-DAC
Forklift	-	-	-	1
Heavy-Duty Vehicle	11	1	38	2
Medium-Duty Vehicle	6	1	9	10
School Bus	4	2	24	15
Transit Bus	2	-	7	3
TRU	2	-	5	1
Total	25	4	83	32

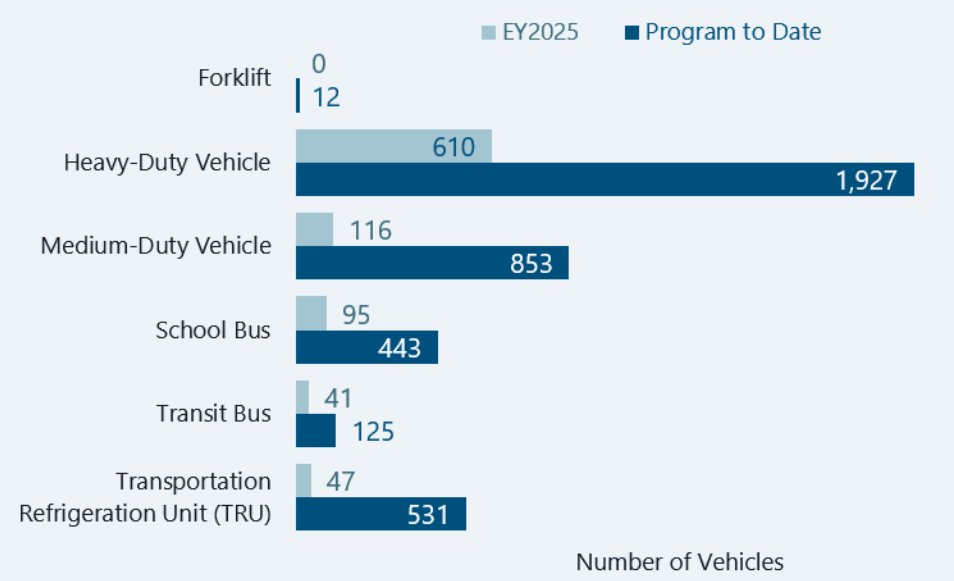
In EY2025, the highest participation rate in the SCE Charge Ready Transport program came from the heavy-duty vehicle market sector, which accounts for 41% of EY2025 activated sites, followed by the medium-duty vehicle market sector with 24% and the school bus market sector, with 21%. The transit bus and TRU market sectors each had two activated sites in EY2025. The forklift market sector had no activated sites in EY2025.

In the SCE Charge Ready Transport program to date, heavy-duty vehicle fleets represent 35% of all activated sites, while school bus fleets account for 34% of activated sites, marking the first year that a non-school bus market sector had the largest share of sites. Medium-duty vehicle and transit bus sites are the next most common market sectors, accounting for 17% and 9% of activated sites, respectively. The TRU market sector accounts for 5% of activated sites, and the forklift market sector is the least represented in the program with one site.

SCE activated 29 sites in EY2025 to support 909 MDHD vehicles across five market sectors based on 10-year VAPs submitted by customers at the time of application. This brings the total number of MDHD vehicles electrified in the Charge Ready Transport program to 3,891. As shown in Figure 61, the heavy-duty vehicle market sector is the largest sector of MDHD vehicles electrified (610, or 67%) in EY2025. The medium-duty vehicle (116, or 13%) and school bus market sectors (95, or 10%) are the next two largest sectors of MDHD vehicle electrified in EY2025. The MDHD sectors with the fewest electrified vehicles in EY2025 include TRU (47, or 5%), and transit bus sites (41, or 5%).

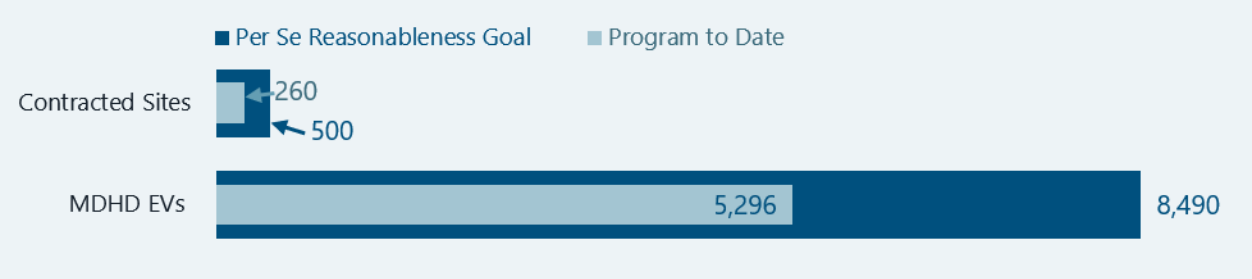
[50] The application and contract totals do not include applications that were withdrawn, rejected, or put on hold.

Figure 61. SCE Charge Ready Transport Program Vehicles Electrified by Market Sector



By the end of EY2025, the SCE Charge Ready Transport program had 115 activated sites supporting the electrification of 3,891 MDHD vehicles per customers' VAPs. The 260 contracts signed in the program to date meets 52% of the program's per se reasonableness site goal. The 260 contracts signed would support 5,296 MDHD vehicles, which meets 62% of the program's per se reasonableness electrified vehicles goal (Figure 62). The total 327 customer applications could satisfy approximately 65% of the program's site goal and would support 6,771 MDHD vehicles, which could satisfy 80% of the program's electrified vehicles goal.

Figure 62. SCE Charge Ready Transport Program
Per Se Reasonableness Site and Vehicle Goal Progress



There were 445 charging ports installed to support 909 electrified MDHD vehicles at the 29 sites activated in EY2025. In the SCE Charge Ready Transport program to date, 2,014 L2 and DCFC ports have been installed at activated sites to support charging of 3,891 MDHD EVs, equating to roughly two vehicles per port.

The CPUC established six phases in the program timeline per the SB 350 reporting template. As presented in Table 27, at the end of 2025, nearly three quarters (70%) of customer applications were either in the activation or the contract issuance phase. Of the remaining applications, the majority were in either the

site assessment or design and permitting phases. The smallest number of applications were in the Application Review phase of the program.

Table 27. SCE Charge Ready Transport Program Sites and Vehicles by Program Phase as of December 31, 2025

CPUC Program Phase	Number of Sites	Total Number of EVs Supported
Application Review	23	412
Site Assessment	41	954
Contract Issuance	98	1987
Design and Permitting	33	492
Construction Complete	-	-
Activation [a]	132	2,844

[a] The number of sites in the activation phase exceeds the number of activated sites in the program to date because the activation phase includes sites that have entered but have not yet completed this phase.

Table 28 shows the median durations per program phase (measured in calendar days) for EY2025 and PTD activated sites, which provides insight into program phase length trends over time. Sites in each column did not necessarily pass through each phase in the same calendar year. For example, EY2025 activated sites may have passed through contract issuance in 2022 while others passed through in 2023 or 2024. Across all program phases, contract issuance and site assessment have the shortest median durations, and design and permitting has the longest median duration.

Table 28. SCE Charge Ready Transport Program Median Calendar Days per Phase for EY2025 and PTD Sites

CPUC Program Phase	Median Calendar Days	
	EY2025 [a]	Program to Date [b]
Application Review	141	117
Site Assessment	46	38
Contract Issuance	26	25
Design and Permitting	429	288
Construction Complete	189	140
Activation	83	43

[a] EY2025" represents the data for the sites activated in 2025.

[b] "Program to Date" represents the data from all activated sites from program inception for all program years.

Median durations also vary by market sector. For instance, for heavy-duty vehicle sites activated in EY2025, the median calendar days for design and permitting was 347 days; however, medium-duty vehicle applications took a median of 699 days to pass through this program phase. The median durations per program phase in EY2025 were similar to the PTD median durations for most of the phases. The design and permitting and activation phases were outliers with notably longer median durations for EY2025 than for the program to date.

Figure 63 expands the analysis of program phase duration for EY2025 by displaying the average number of calendar days per phase (denoted by X), calendar day median (middle line inside of box), first quartile (bottom of box), third quartile (top of box), minimum (bottom tail), maximum (top tail), and outliers (dots). Program applications experienced the most variation in completion time within the design and permitting phase, which involves an external review and substantial back-and-forth communication with applicants to finalize site layout, design, easements, and conveyances, if required. This was followed by Application Review, for which the high degree of variation in completion time most likely resulted from scope changes requested by customers, engineering capacity studies, and the communication required between program administrators and applicants to ensure that applicants had completed the required documentation. Customer applications in the site assessment, contract issuance, and activation phases experienced the lowest mean and variance in calendar days among all the program phases, despite a few outliers.

Figure 63. SCE Charge Ready Transport Program Calendar Days per Phase for EY2025 Sites

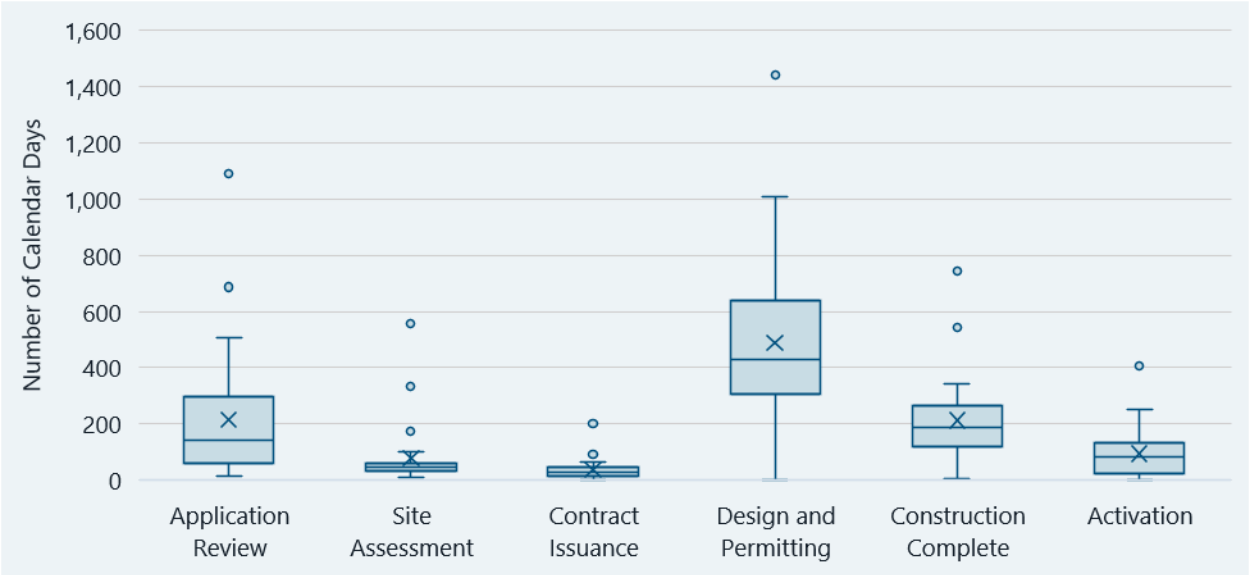


Table 29 displays the median number of calendar days that the Charge Ready Transport program site activation process took from start to finish (Application Review to Activation) for 29 activated sites across five market sectors in EY2025 and the median for the program to date. The overall median start-to-finish timeline for site activation for EY2025 sites was 1,228 calendar days, an increase of 269 days from the median in EY2024 (959 days), which was a single-day shorter than in EY2023 (960 days). As displayed in Table 29, median start-to-finish durations varied widely across market sectors from 945 days for heavy-duty vehicle sites to over five years for TRU sites (1,887 days) in EY2025. The 115 PTD activated sites had an overall median start-to-finish duration of 869 days.

Table 29. SCE Charge Ready Transport Program Median Duration in Calendar Days for Site Activation by Market Sector for EY2025 and PTD Sites

Market Sector	EY2025		Program to Date	
	Median Duration Start-to-Finish	Number of Activated Sites	Median Duration Start-to-Finish	Number of Activated Sites
Forklift	-	-	1,018	1
Heavy-Duty Vehicle	945	12	869	40
Medium-Duty Vehicle	1,455	7	1,092	19
School Bus	1,090	6	771	39
Transit Bus	1,785	2	1,120	10
TRU	1,887	2	1,073	6
All Market Sectors	1,228	29	869	115

Program Materials Summary

In 2025, SCE's marketing, education, and outreach (ME&O) core tactics for the Charge Ready Transport program remained consistent with previous years, but to maximize program participation, specialized targeted outreach was conducted aligning with MDHD EV adoption trends and market conditions. The base ME&O tactics included attending in-person events, hosting webinars, developing partnerships, and performing targeted outreach. The specialized efforts included a Voice of the Customer market study, a Fleet Electrification Learning Session featuring an in-person site walk and live case study with a local school district; and a CARB + SCE two-part transit focused webinar Series. Other notable tactics include the School District ZEV Transition Plan Workshop, case study with another local school district, and a robust paid social media marketing campaign. The content of marketing materials was designed for general outreach and focused on the sectors with active transportation electrification regulations, funding, and EV availability. SCE shifted its marketing tactics back in 2024 following an in-depth strategic refresh effort. In previous years, SCE staff marketed the program broadly to all fleets in its service area, and in 2024 the Utility narrowed the scope of its marketing to increase its impact. Targeted customers included schools and transit agencies, both of which are most affected by regulatory pressure, a key driver of electrification. Additional factors that influenced targeting were availability of funding for certain customers and market readiness and urgency.

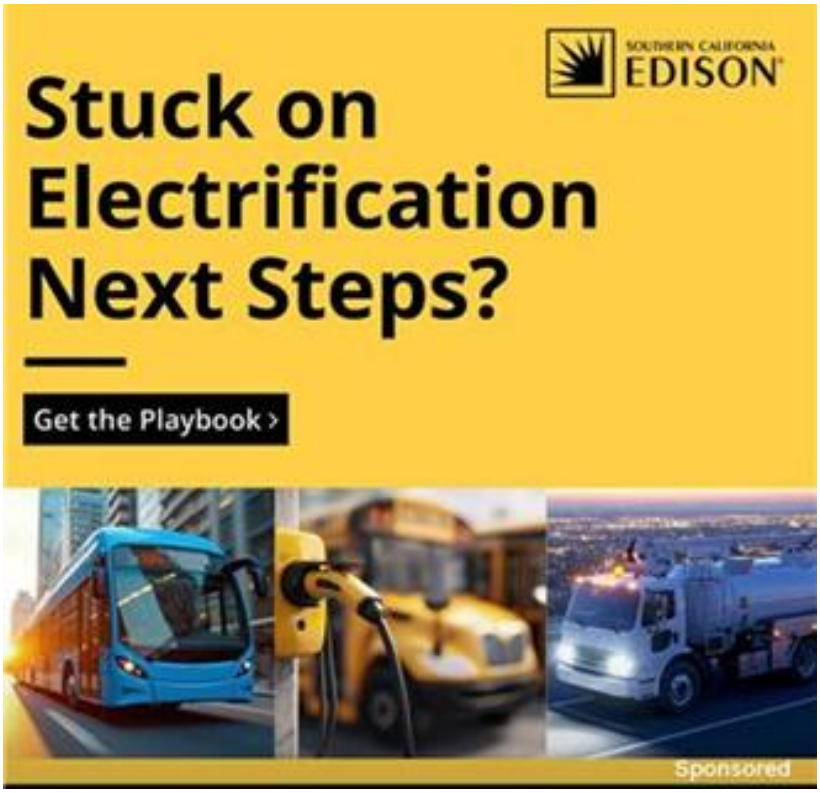
This section highlights key findings from the review of program materials and ME&O activities SCE conducted in 2025:

- **Consistent Marketing Efforts.** SCE staff continued utilizing marketing pathways and tactics including industry working group webinars, in-person and virtual site walks, as well as case studies from successful projects. Staff noted that CARB has continued to be a key partner in areas such as webinars, as regulatory clarity was a top area of concern for fleet procurement decisions.
- **Focus on Electrification Education.** In 2025, outreach activities involved educating customers on the benefits of electrification and programmatic pathways to help make the transition a reality. In frequent collaboration with Transportation Electrification Advisory Services (TEAS), Charge Ready Transport staff positioned themselves as trusted advisors for customers in their electrification journey, as staff understand that many are not getting sufficient information from infrastructure

and vehicle vendors. Through 2025, SCE staff held numerous virtual and in person fleet electrification sessions with schools, local governments, and other fleet managers. One in-person Fleet Electrification Learning Session SCE hosted had over 50 school districts in attendance, many of which transitioned to program applications.

- **Fleet Readiness Sessions.** As part of the SCE Transit Fleet Electrification Learning Series and in collaboration with CARB, SCE staff hosted a two-part webinar series focused on helping transit agencies understand and prepare for zero-emission bus requirements under California's Innovative Clean Transit (ICT) regulation and plan for a long-term electrification strategy. The sessions covered current and upcoming ICT purchase requirements and explained the full process of EV infrastructure deployment, from site design and construction to utility coordination, grid readiness and integration of distributed energy sources like solar and battery storage.
- **New Educational Media Campaign.** SCE staff launched a new targeted paid social media campaign in 2025 that directed customers to a "Building your EV Fleet Strategy" eBook designed to educate potential participants on fleet electrification and further establish SCE as a trusted advisor. The eBook guided readers through the priorities of fleet electrification, provided them with checklists and resources, and directed them to apply to the Charge Ready Transport program. The campaign targeted market sectors that the program team determined to be impactful: commercial fleet operators, municipal and public agencies, school districts, and private depots. Figure 64 shows an advertisement for the eBook.

Figure 64. SCE Charge Ready Transport Program Media Campaign

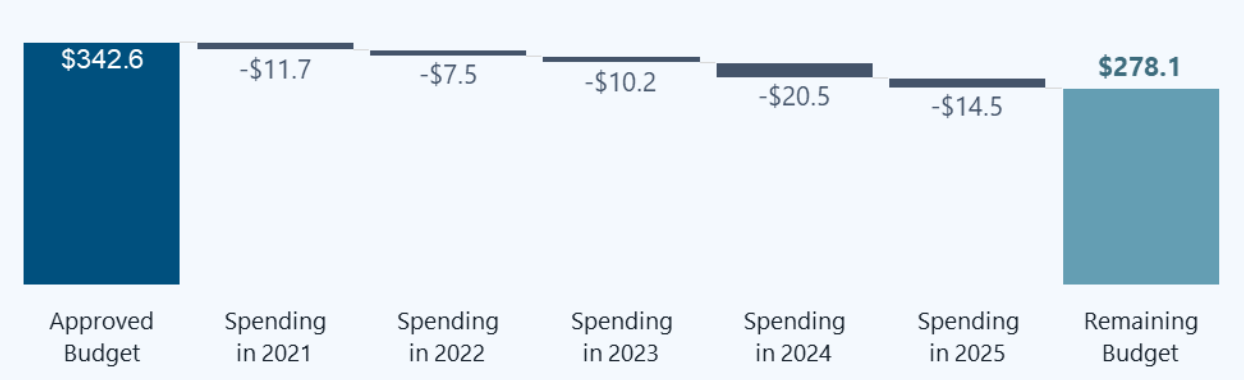


- **Leveraging Customer Feedback.** The program team placed a strong emphasis on understanding customer needs and incorporating their feedback into program design. Staff asked customers directly what they wanted and used that input to shape program offerings. For example, staff sent out more than 103,000 survey invitations, resulting in 111 surveys completed. The insights gained from this effort helped ensure alignment with industry needs. Staff also asked participants to submit questions in advance of webinars so that content could be tailored to address their specific concerns and priorities.
- **Case Study Engagement.** In 2025, SCE staff continued to present fleet operators with peer case studies of similar customers who had electrified their fleets through the Charge Ready Transport program. Case studies guide readers through the process the example fleet took, highlighting the fleet's specific needs, the support SCE provided, other funding used for the site, and the positive impact of the project. In 2025, case studies were delivered through various learning formats to include digital delivery, live-virtual, and in-person experiential events

Budget Summary

As shown in Figure 65, from program inception through December 31, 2025, SCE has spent $64.5 million of $342.6 million (constant dollars) of the approved Charge Ready Transport program budget.[51] In 2025, program spending was $14.5 million.

Figure 65. SCE Charge Ready Transport Program Budget (Millions USD) as of December 31, 2025 [a]



[a] Annual spending may not sum to total spent due to rounding.

[51] The amount spent accounts for activated sites that have been fully financially closed out and for administration and marketing costs incurred through the end of 2025. Costs are considered spent/recorded as incurred after a site is fully complete and invoiced, which includes the payment of rebates that require the customer to submit paperwork. Only 40% of sites in the pipeline are activated (see Table 27), which means the figure undercounts the expenses to date as it does not include any reserved or committed funds for projects in progress.

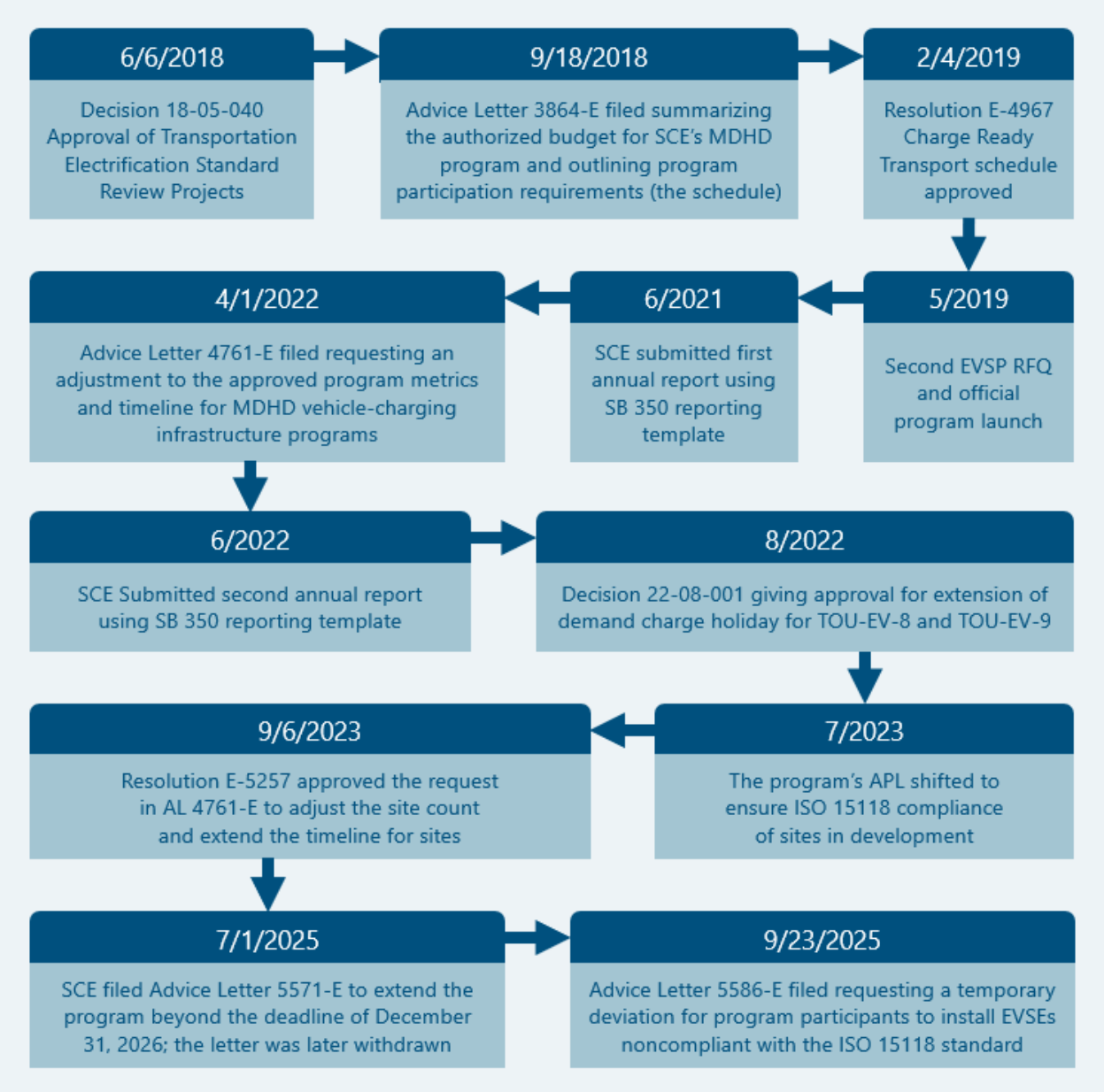
Timeline

Since the beginning of the Charge Ready Transport program, SCE has filed four Advice Letters. In 2018, SCE filed AL 3864-E summarizing the authorized budget for the program and outlining program participation requirements (the schedule). In February 2019, Resolution E-4967 approved the schedule. In 2022, SCE filed AL 4761 jointly with PG&E, requesting an adjustment of the site count from 870 to a range between 470 and 870 sites, an extension of the program timeline, and changes to the vehicle purchase or conversion requirements for public charging sites for MDHD vehicles. In July of 2023, SCE staff confirmed that the program was required to comply with International Organization for Standardization (ISO) 15118 standard.[52] ISO 15118 covers communication between EVs and charging systems, which affects the range of equipment on the APL that program participants may choose. In September 2023, Resolution E-5257 approved the site count adjustment to a minimum of 500 sites and granted the timeline extension but denied the request to modify vehicle purchase or conversion requirements for public charging sites for MDHD vehicles. In July 2025, SCE submitted AL 5571-E requesting an extension to the program deadline but withdrew the request after the CPUC opened another proceeding, Rulemaking 23-12-008, concerning the future of transportation electrification in the state. In December 2025, CPUC Decision 25-12-005 removed the vehicle purchase requirement for Charging as a Service (CaaS) sites and laid out a process for the Utilities to develop a vehicle-per-port ratio for these sites. Sites for the Charge Ready Transport program must be fully contracted for by December 31, 2026, but will continue construction beyond 2026 as needed. In September 2025, SCE filed AL 5586-E requesting a temporary deviation from ISO 15118 compliance requirements for certain EVSE under the program.

Figure 66 shows all major milestones from the beginning of the program.

[52] Although the ISO 15118 went into effect in 2023, it was clarified in the 2024 close out interviews that the program needed to retroactively comply with this standard.

Figure 66. SCE Charge Ready Transport Program Key Milestones



4.1.2. Findings

The following sections present evaluation findings from the Charge Ready Transport program, including utility staff insights, fleet manager survey results, findings from interviews and site visits, co-benefits and co-costs, site costs, grid impacts, charging flexibility, petroleum displacement, GHG and criteria pollutant impacts, health impacts, and overall net impacts.

Table 30 summarizes key impact parameters for EY2025 sites as well as for the program to date. Annual estimates of impacts are provided for metrics calculated as part of the impact evaluation. The table provides estimates of impacts across all sites included in the program population through the end of 2025.

Table 30. SCE Charge Ready Transport Program Impacts Summary

Impact Parameter	EY2025 Sites [a]	EY2025 Sites Percentage in DAC	PTD Sites Actual	PTD Sites Actual Percentage in DAC
Population of Activated Sites	29	86%	115	72%
Sites Included in Analysis	29	86%	115	72%
Ports Installed in Analyzed Sites	445	86%	2,014	81%
EVs Supported [b]	909	83%	3,891	78%
Electric Energy Consumption (MWh)		95%		87%
Petroleum Displacement (DGE)	847,850	95%	8,091,560	85%
GHG Emission Reduction (MT) [c]	7,123	94%	65,633	86%
NO_X Reduction (kg)	3,274	95%	59,520	95%
PM_{10} Reduction (kg)	63.6	98%	573	95%
$PM_{2.5}$ Reduction (kg)	59.8	97%	545	95%
ROG Reduction (kg)	685.2	99%	5,147	89%
CO Reduction (kg)	60,726	100%	225,616	59%

[a] Energy consumption, petroleum displacement, and emissions reductions are based on annualized data. Program-to-date results are based on actual data (see *Appendix B* for details).

[b] The Evaluation Team derived the EVs supported value from applicants' VAPs. This value represents the maximum number of vehicles expected to be supported by the charging infrastructure.

[c] GHGs include CO_2, CH_4, and N_2O multiplied by their respective GWP as defined by IPCC AR5 (see *Appendix B* for details).

Utility Staff Insights

In addition to monthly check-in calls with key SCE staff to discuss the status of the Charge Ready Transport program, the Evaluation Team conducted close-out interviews with staff in January 2026 to review overall program challenges and successes in 2025. The following bullets describe challenges reported by Charge Ready Transport customers and SCE staff:

- **Regulatory Uncertainties.** SCE staff reflected that numerous regulatory changes contributed to increased customer wariness about sites and a general lack of clarity around the regulatory environment. Many customers still expressed a desire to electrify their fleets. Regulatory uncertainties at the state and federal level caused some delays to their plans. This regulatory complexity, which has resulted in customers requiring increased support from SCE staff to navigate, is a continuation of challenges from previous years.
  - **ACF Waiver Withdrawal.** In January 2025, CARB withdrew its request for a Clean Air Act waiver for California's ACF regulation in the face of federal government opposition. CARB had already paused enforcement of the regulation in 2024 as the withdrawal was considered, so this decision to withdraw the waiver offered some clarity; however, its absence reduced the incentive for many customers to electrify their fleets.

  - **Charger Port Standards Changes.** Changing port standards among EV manufacturers, specifically the shift from Combined Charging System (CCS) to North American Charging Standard (NACS), has caused customer confusion with planning. Because the technology and the regulatory environment are evolving so rapidly, customers are afraid that what they buy will quickly become obsolete or will not allowed. This issue continued in 2025, when some customers experienced issues using non-ISO 15118-compliant chargers for their Tesla Semi vehicles, which SCE addressed by requesting a temporary deviation from the CPUC, approved in September 2025, until a compliant charger was added to the APL.
  - **Removal of Federal Funding.** In 2025, the federal government moved to end several sources of federal funding for EV fleets, directly impacting some Charge Ready Transport customers and adding to the lack of clarity around available regulatory and financial support for sites. One such affected program was the EPA's Clean School Bus program.
  - **Federal Tariff Confusion.** New tariffs on international trade in 2025 have caused uncertainty for customers about ports and other infrastructure parts that are sourced from abroad, especially as tariffs have fluctuated and faced legal challenges.

- **Permitting Challenges.** SCE staff noted issues with a variety of permitting processes as a significant challenge in 2025, slowing site delivery. These challenges were driven by delays in securing third-party easements and inconsistent and non-standardized requirements from self-permitting agencies (such as school districts). Sites constructed on properties that require Division of the State Architect (DSA) review added further complexity because some state-level requirements differ from the city and county codes, such as the need for additional seismic impact reviews.
- **Vendor-Driven Skepticism.** As the EV market continues to mature in an unstable regulatory environment, many vehicle and charging infrastructure vendors have filed for bankruptcy or experienced other challenges, leading to a negative perception of the market among some customers. Customers looking to protect themselves against future instability may be dissuaded from investing in electrification in the short term by such market fluctuations. The shuttering of vendor businesses has been an additional challenge for SCE staff when it occurs during site development and requires staff to help customers replace or find a new vendor for their equipment.
- **Supply Chain Issues and Build America, Buy America.** Build America, Buy America (BABA), part of the 2021 Infrastructure Investment and Jobs Act, emerged in 2025 as a significant new external requirement for the Charge Ready Transport program and its customers. Because the Charge Ready Transport program was not originally designed with BABA in mind, SCE staff are now working to identify solutions for both existing and future projects. The regulation, which requires domestic sourcing for materials and equipment for a project to be eligible for federal funding, creates complexity because some federal agencies extend BABA rules to ratepayer-funded EV Infrastructure if the infrastructure supports the federally funded program. Because customers risk losing their federal funding if SCE infrastructure isn't BABA compliant, SCE staff are required to work toward BABA-compliant buildouts and proactively expand customer education to prepare customers for upcoming obligations.

- **Site Readiness Challenges.** SCE staff emphasized that while its internal vetting process has improved through accumulated experience and better understanding of site feasibility, significant challenges persist on the customer side. A major barrier is customer indecision: fleet operators frequently change preferred charging locations after initial site visits, often based on new input from general contractors or newly hired consultants. These shifts trigger cascading complications, such as the need to reassess easements, engage neighboring property owners, or secure different permits. Staffing turnover within customer organizations further disrupts continuity, as new personnel may alter project direction or bring in different consultants. Each change forces the Utility to pivot mid-process, slowing progress and increasing the complexity of delivering site readiness support.

SCE staff also reported notable successes in 2025:

- **Continued Process Improvements.** As in previous years, SCE staff continued to hone the process of working with customers to develop Charge Ready Transport sites.
  - **Enhanced Customer Communication.** SCE staff strengthened its customer-facing processes, improving clarity, communication, and overall project flow. For example, program staff organize meetings between their construction management team and customers to keep the team updated on site status and customer requirements following the typically long pre-construction document collection period, which minimizes lost knowledge from personnel turnover. These types of refinements helped projects move more smoothly and improved customer understanding of requirements and next steps. Leveraging lessons learned from previously completed sites, SCE staff also identified categories of site changes for customers to consider early in the process, which allows customers to more effectively anticipate and address these changes without the site needing to revert to the beginning of the process.
  - **Modified Site Implementation.** The team proactively shifted several project steps to earlier in the timeline to reduce delays and increase adaptability. For example, switchgear ordering now begins when a site enters permitting rather than after design completion, and engineering consultations and environmental reviews are initiated earlier to keep projects moving before program windows close. This allows SCE staff to pivot or adjust sites before problems that have historically plagued site construction can arise.
  - **Strengthened Construction Oversight.** SCE added a new Behind-the-Meter Manager role to oversee contractor coordination, manage logistics across five general contractors, and implement additional safety and quality checkpoints. This role has significantly improved oversight, consistency, and operational efficiency across Charge Ready Transport sites.
- **Institutional Knowledge and Long-Term Capacity Building.** Even though the Charge Ready Transport program is winding down new applications, SCE staff have built substantial institutional expertise, tools, and curriculum that will continue to support MDHD fleet programs and offerings moving forward. SCE will leverage this accumulated capacity to expand its TEAS program, ensuring continuity and long-term value beyond the current program.

Looking ahead at the future of fleet electrification, SCE staff identified several market factors that continue to influence EV adoption. The significant time required to prepare applications, install infrastructure, and

complete energization poses a major challenge for many fleets. In addition, uncertainty around potential regulatory changes creates hesitation for fleets to electrify, as regulatory compliance remains a key driver of electrification decisions. Although availability of EVs and EVSE has improved as the market has matured, this remains a constraint for some sites.

SCE staff noted that success stories and positive experiences from other participants play an important role in encouraging additional fleets to pursue electrification projects. As more fleets electrify and share their journeys, having a greater understanding of project scope helps future fleets better anticipate project needs and enter the process more confidently.

Highlights

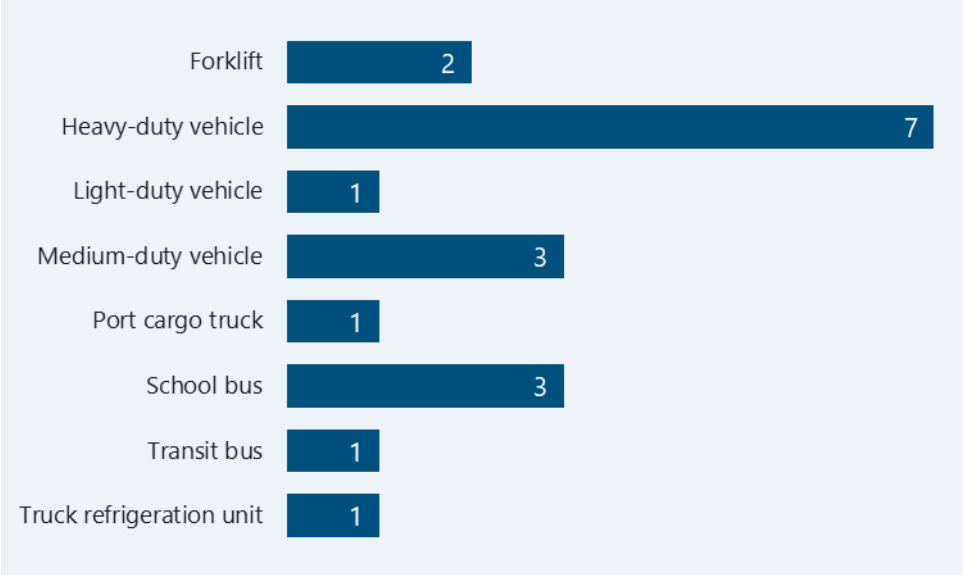
- Growing institutional knowledge within the Charge Ready Transport program team and increasing fleet success stories support building long-term readiness for market influence and strengthen customer confidence in fleet electrification both within and beyond the Charge Ready Transport program.
- Staff improved project efficiency by refining customer-facing processes, proactively accelerating some steps that have caused delays, and adding new construction oversight.
- Regulatory changes that affect site motivations and funding, including the withdrawal of the ACF waiver, contributed to uncertainty among customers that made many fleets hesitant to electrify.
- Permitting delays, vendor instability, site-readiness issues, and supply challenges continued to slow site delivery and increase complexity for SCE and customers.

Survey Results

The Evaluation Team surveyed participating fleet managers about their motivations for and barriers to electrification, satisfaction with and awareness of the Charge Ready Transport program; experience with EVs and charging infrastructure; and perspective on the industry. The Team received a total of 10 complete survey responses and six partial responses. As shown in Figure 67, the fleet managers span seven market sectors. Nine of the fleet managers reported that their fleets consisted of vehicles from only one market sector, while three others had vehicles from two or three market sectors in their fleet.

Heavy-duty vehicles were the most common among respondents, with most fleet managers (7 of 10) reporting these vehicles as part of their fleet.

Figure 67. SCE Charge Ready Transport Program Participant Market Sectors in Fleets

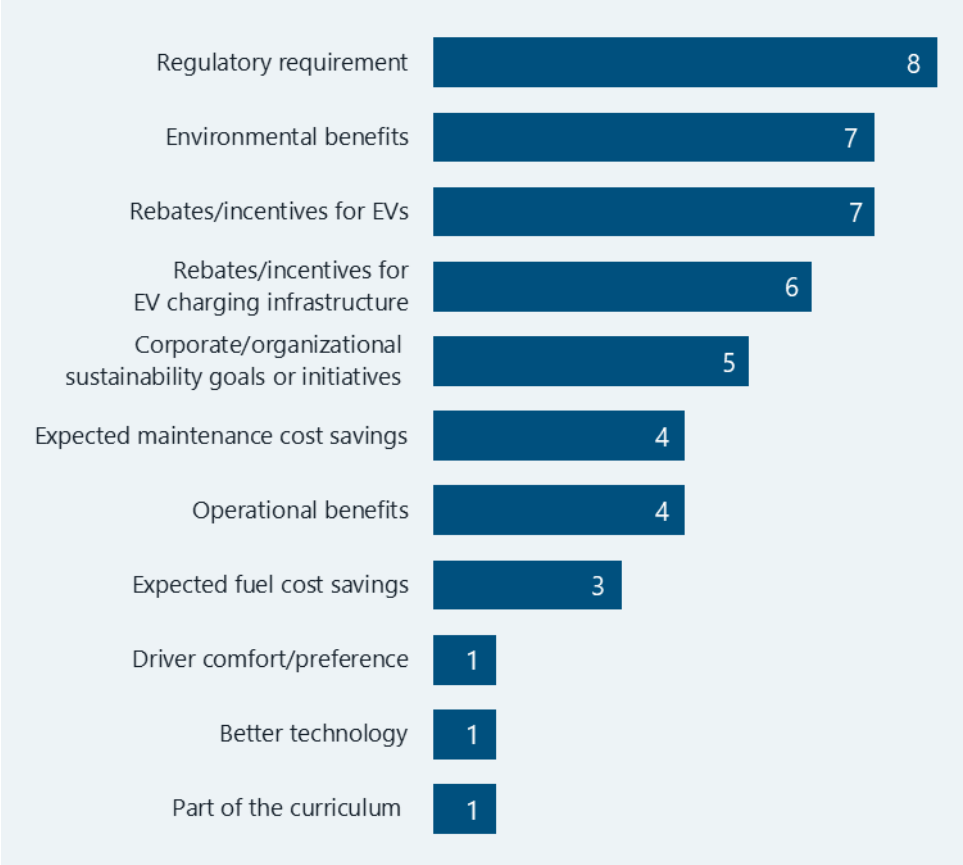


Source: Fleet Manager Survey Question A1 "What types of vehicles/equipment do you have in your fleet?" (n=13, multiple responses accepted)

Electrification Motivators and Barriers

The Evaluation Team asked fleet managers about their motivations for transitioning to EVs. As shown in Figure 68, the top motivator was the regulatory requirement, cited by eight of 10 respondents. The next most common motivators were environmental benefits and rebates/incentives for EVs, both cited by seven fleet managers. Rebates/incentives for EV charging infrastructure and corporate/organizational sustainability goals or initiatives were identified as motivators by six and five respondents, respectively. Reported motivators were similar in EY2024, when environmental benefits (10), regulatory requirement (7), and rebates/incentives for EVs (7) were the most commonly cited by 13 respondents. Regulatory requirement has been cited as a top motivator only since 2024, after being one of the least common motivators in EY2023, chosen by only two respondents of seven, which was similar to EY2022, when it was chosen by one of four respondents, and EY2021, by two of six respondents.

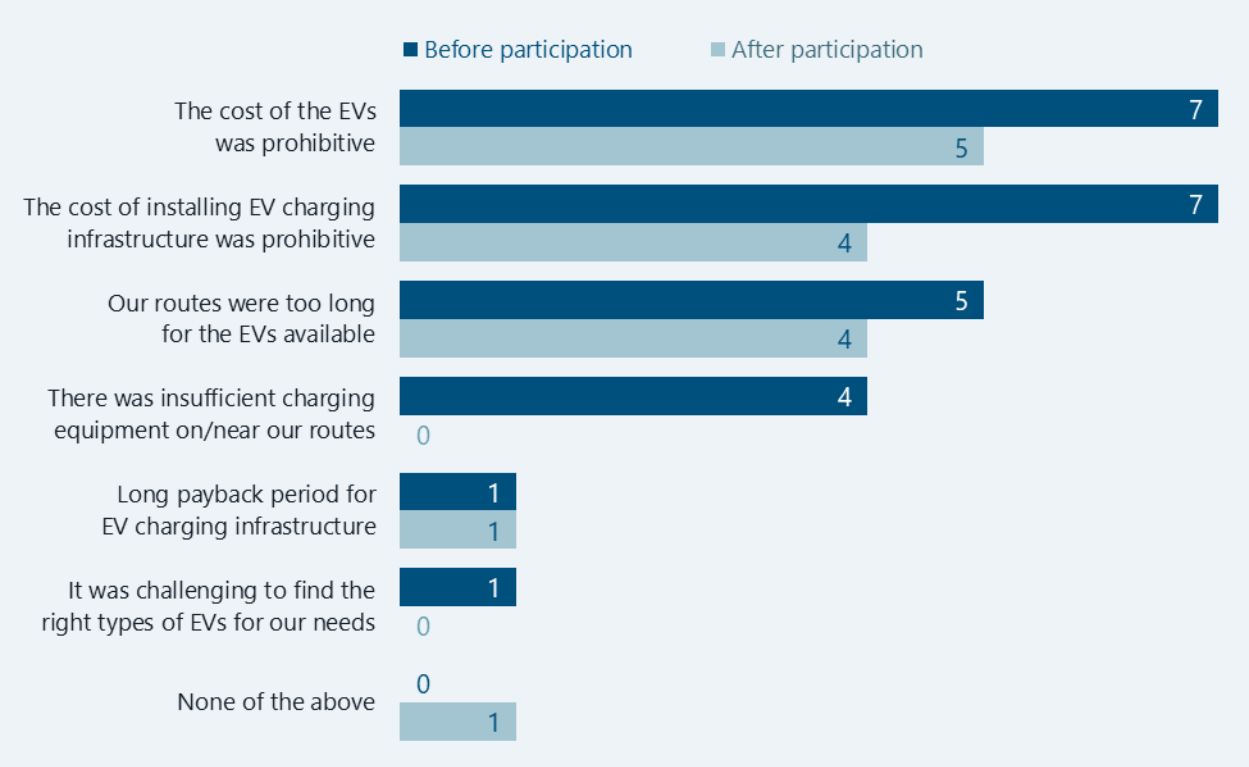
Figure 68. SCE Charge Ready Transport Program
Participant Motivators for Transitioning to EVs in EY2025



Source: Fleet Manager Survey Question C1 "Why did your fleet decide to transition to EVs?" (n=10, multiple responses accepted)

The Evaluation Team asked fleet managers which barriers to electrification their fleets had faced before participating in the Charge Ready Transport program and which remained after participation. Figure 69 shows that prior to participating, fleet managers saw the cost of both EVs and installing EV charging infrastructure as the biggest barriers to electrification, mentioned by seven respondents each. The next most mentioned barriers to electrification before participating were fleet managers' routes being too long for the EVs available, mentioned by five respondents. After participating, nearly all barriers were reported by fewer fleet managers. The barrier reported by the most fleet managers after participating continued to be the cost of EVs, mentioned by five respondents. Most notably, four fleet managers reported that insufficient charging equipment on/near routes was a barrier before participation, but zero reported it as a barrier after participating in the program. Cost of EVs and EV charging infrastructure were the top barriers before participation in EY2024, EY2023, EY2022, and EY2021 as well. In all years these costs were cited as barriers by fewer fleet managers after program participation but remained the most common barriers to electrification.

Figure 69. SCE Charge Ready Transport Program Barriers to Electrification Before and After Program Participation in EY2025



Source: Fleet Manager Survey Questions F3 and F4 "Which of the following barriers to electrification did your fleet face before participating in the EV Fleet program?" and "You mentioned that the following were barriers to electrification before participating in the Charge Ready Transport program. Do any of these barriers still exist after you participated in the program?" (n=10, multiple responses accepted)

Program Satisfaction

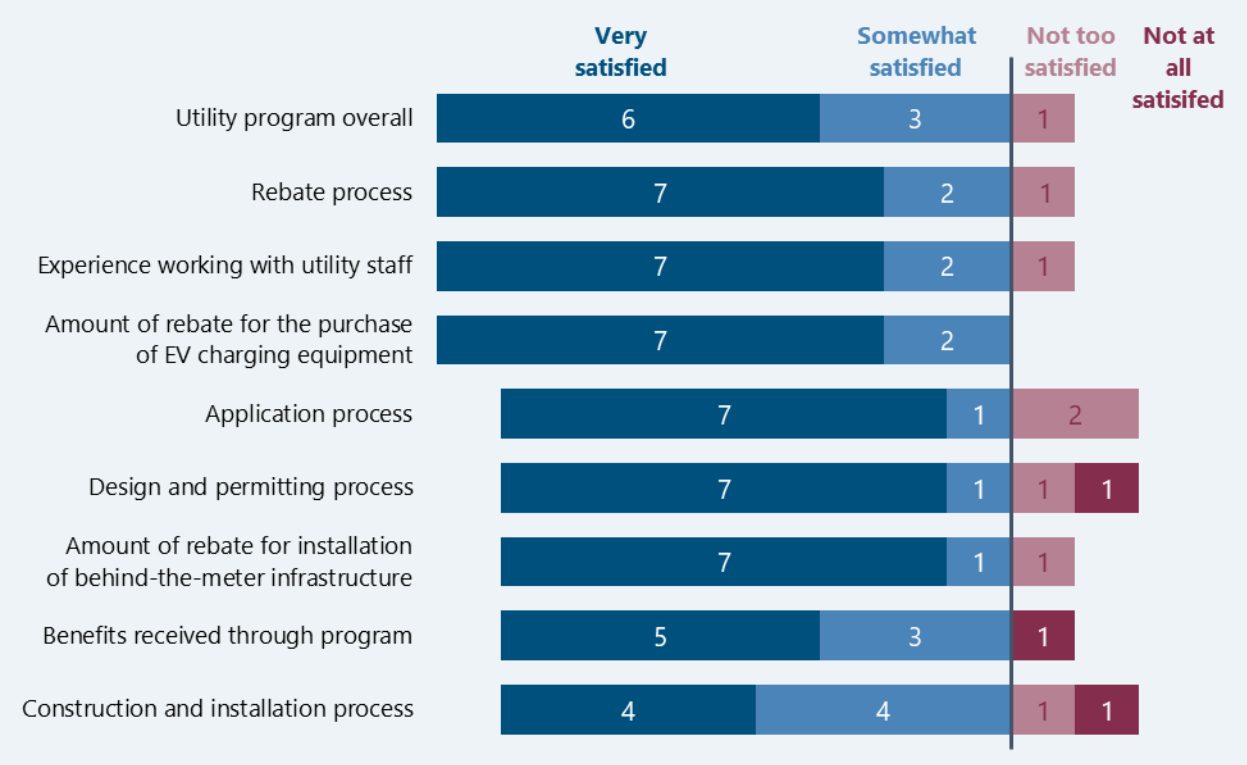
The Evaluation Team asked fleet managers to rate their satisfaction with the Charge Ready Transport program overall and with specific elements of the program. Across all program elements, fleet managers generally reported strong satisfaction (Figure 70). Fleet managers were mostly satisfied with the program overall, with six managers rating themselves as *very satisfied*, three rating themselves as *somewhat satisfied*, and one providing a rating of *not too satisfied*. The program elements that received the highest satisfaction ratings were the rebate process, the experience of working with utility staff, and the amount of the rebate for the purchase of EV charging equipment, for which seven respondents rated themselves as *very satisfied* and two rated themselves as *somewhat satisfied*. Fleet managers expressed the least satisfaction with the design and permitting process and the construction and installation process, with each receiving one rating of *not too satisfied* and one of *not at all satisfied*.

When asked about what they were particularly satisfied with, three respondents highlighted the help and communication they received from SCE program staff throughout the process. Fleet managers also explained aspects of the program with which they were particularly dissatisfied. Two fleet managers struggled with there being "not enough flexibility in the process," with one saying they wanted to install

more chargers that would remain below load restrictions using load management software but the program limited the chargers to fewer than they wanted. Three fleet managers were dissatisfied with the time it took to complete their site through the program, mentioning permitting and employee turnover at SCE as particular challenges. One fleet manager said they wished the program allowed for the integration of battery storage and other distributed energy technology, an option only included in the program for projects with customer-built infrastructure, which they believed would "improve energy management, operational flexibility, and system efficiency."

Satisfaction with the SCE Charge Ready Transport program in 2025 was similar to satisfaction reported in EY2024, EY2023, EY2022, and EY2021, with the majority of fleet managers expressing satisfaction with the program. Many aspects of the program, such as the experience working with Utility staff and the amount of the rebate, remained areas of highest satisfaction for fleet managers. Fleet managers were slightly less satisfied with the application process in EY2025 than in EY2024, when none said that they were dissatisfied. The construction and installation process continued to receive the lowest satisfaction ratings from EY2024 to EY2025, though in both years more participants were satisfied than dissatisfied.

Figure 70. SCE Charge Ready Transport Program Satisfaction with Program Elements in EY2025



Source: Fleet Manager Survey Question B1 "Thinking about your experience with the Charge Ready Transport program, how satisfied are you with the following?" (n=10)

The Evaluation Team asked fleet managers how likely they were to recommend the Charge Ready Transport program to another company on a scale of 0 to 10. Half of respondents (5 of 10) said they had already recommended the program to other companies. One fleet manager rated their likelihood of

recommending the program as 8, one rated it as 7, one as 6, and two rated it as 5, resulting in a Net Promoter Score (NPS) of +20.[53] This continues a drop in NPS scores since EY2022 from +33 in EY2024, +83 in EY2023, +100 in EY2022, and +83 in EY2021. Two fleet managers who rated their likelihood to recommend as only 5 or 6 cited the long timeline of program participation as an area of frustration.

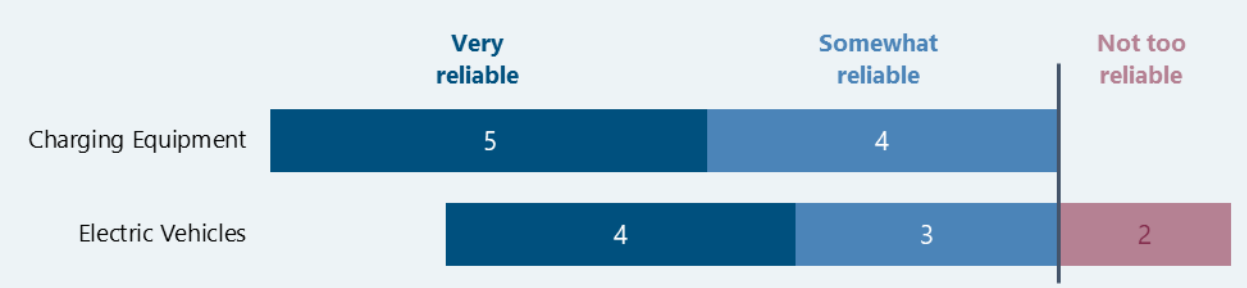
Program Awareness

The Evaluation Team asked fleet managers how they had learned about the Charge Ready Transport program. Six of the nine respondents learned about the program directly from SCE, two from an EV/EVSE manufacturer, and one from their corporate office. SCE staff were the top source of program awareness for fleet managers in EY2024 (8 of 12), EY2023 (4 of 6), EY2022 (3 of 4), and EY2021 (3 of 5). Four of 10 fleet managers reported that they were aware that they needed upgrades to the electrical infrastructure from the utility grid to their meter to charge EVs at their site, while six were not.

Experience with EVs and Charging Infrastructure

When asked to rate the ease of use of their EV charging equipment, all fleet managers indicated that the equipment was easy to use, with six respondents saying their charging equipment was *very easy* to use and three others reporting that the equipment was *somewhat easy* to use. The Evaluation Team asked fleet managers to rate the reliability of their EVs and the charging equipment, as shown in Figure 71. Fleet managers overall found their EV charging equipment to be more reliable than their EVs, with two rating their EV as *not too reliable* and none rating the charging equipment as *not too reliable*. Fleet managers also reported high reliability in EY2024, EY2023, EY2022, and EY2021, although overall in EY2024 fleet managers found EVs to be more reliable than EV charging equipment.

Figure 71. SCE Charge Ready Transport Program Reliability of Vehicles and Charging Equipment in EY2025



Source: Fleet Manager Survey Questions C3 and C4 "How would you rate the reliability of the EVs that are part of your fleet?" and "How would you rate the reliability of the EVSE?" (n=9)

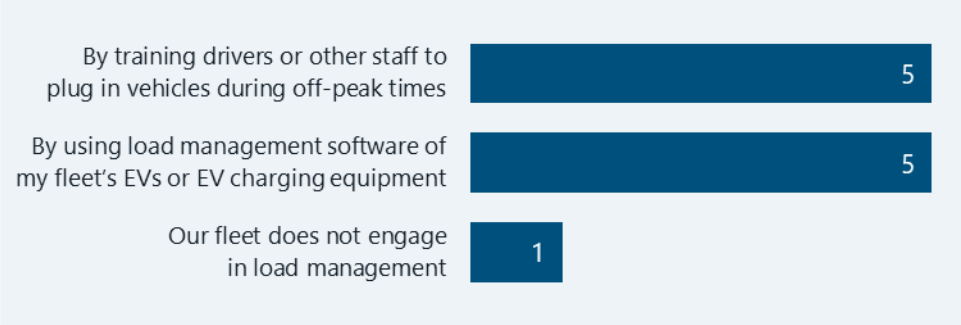
[53] The NPS is a metric of brand loyalty that measures how likely customers are to recommend a program to others. Respondents rate their likelihood to recommend the program on a 0 to 10 scale, where 0 means *not at all likely* and 10 means *extremely likely*. Respondents who give a rating of 9 or 10 are known as promoters, those who give a rating of 7 or 8 are known as passives, and those who give a rating of 0 to 6 are known as detractors. The NPS is expressed as a number between -100 and +100 that represents the difference between the percentage of promoters and the percentage of detractors (with passives excluded from the calculation).

Experience with Load Management and EV Charging

Asked whether they knew that SCE charges different electricity rates per kilowatt-hour depending on the time of day, all nine responding fleet managers said they were aware of this. Asked further whether they were aware of the cost to their company to charge their fleet, five of nine fleet managers said they were aware of the cost, while four said they were not. In EY2024, all 13 responding fleet managers said that they were aware of SCE electricity rates and 10 of 13 said that they were aware of the cost of charging their fleet.

The Evaluation Team asked fleet managers if they took any actions to ensure that they purchased the lowest-cost electricity for charging their fleet or, in other words, if they participated in load management. Seven of eight respondents reported that they did so. The Evaluation Team asked those respondents who reported practicing load management what specific actions they took, with results shown in Figure 72. Five fleet managers each said that they trained drivers or other staff to plug in vehicles during off-peak times and used load management options included with their EVs or EV charging equipment. In EY2024, 10 of 13 fleet managers said that they practiced load management, with training on when to plug in vehicles as the most common method (7 of 13).

Figure 72. SCE Charge Ready Transport Program Participant Load Management Practices



Source: Fleet Manager Survey Question C12 "What actions, if any, do you take to ensure you are purchasing the lowest cost electricity for charging fleet vehicles? A term you may have heard for this is load management" (n=8, multiple responses accepted)

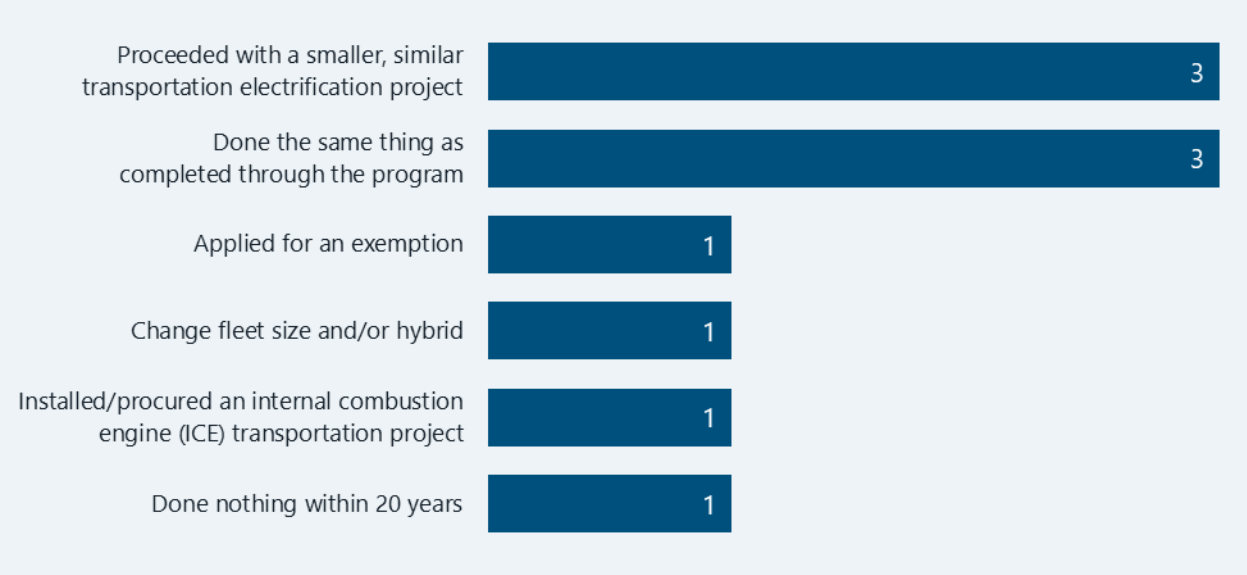
The Evaluation Team also asked the seven fleet managers who practiced load management to provide their reasons for implementing the strategy. All seven fleet managers reported that they implemented load management to lower the cost of charging via charging time management and three did so to manage the stability of their electrical system. Fleet managers' reasoning for load management was similar in EY2024, when seven of 13 reported that they implemented load management to lower the cost of charging via charging time management, three to manage the stability of their electrical system, and two to reduce the need to install additional power sources. The one fleet manager who said that their fleet did not practice load management said that they did "not have the capacity to put [load management] into place [or] manage the process."

Impact of Program on Fleet Electrification

The Evaluation Team asked fleet managers whether they planned to accelerate procurement of EVs and related equipment because of their experience with the program. Three respondents said that they would accelerate procurement, two reported that they planned to slow procurement, and five did not plan to change their procurement plans. In EY2024, five of 13 fleet respondents said they planned to accelerate procurement, three planned to slow procurement, and five did not plan to change procurement. In EY2021 through EY2023, no fleet managers said that they planned to slow procurement, all saying that they would accelerate or keep their procurement plans unchanged.

As shown in Figure 73 the Evaluation Team asked fleet managers what they would have done regarding electrification if the SCE Charge Ready Transport program had not been available. Three fleet managers said they would have proceeded with smaller but similar electrification projects, with one estimating that they would have reduced their site size by 10%, one by 40%, and the last by two thirds. Three fleet managers said they would have done the same thing as what they did through the program, and one each said they would have applied for exemption from regulations, proceeded with an ICE transportation project, changed their fleet size or gone with a hybrid of EV and ICE, and done nothing within 20 years.

Figure 73. SCE Charge Ready Transport Participant Actions if the Program Were Not Available



Source: Fleet Manager Survey Question G1 "If the SCE fleet electrification program had not been available, which of the following alternatives would you organization most likely have done?" (n=7)

Twelve fleet managers reported their planned acquisition of EVs over the next five and 10 years, shown by sector in Table 31.

Table 31. SCE Charge Ready Transport Program
EV Acquisition Projection by Vehicle Type in EY2025 (n=12)

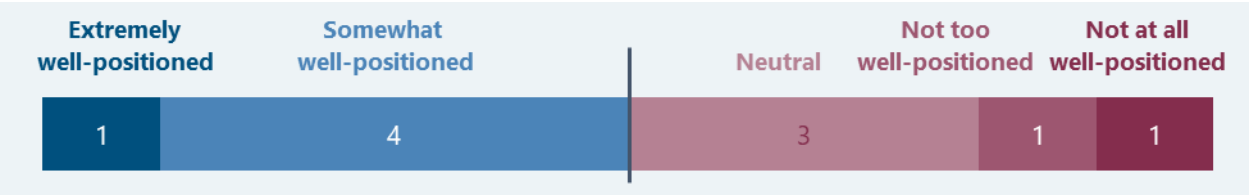
Market Sector [a]	Current Fleet Size		EV Projection	
	ICE	EVs	5 years	10 years
Forklift (n=2)	214	1	2	5
Medium-duty vehicle (n=7)	12	2	4	7
Heavy-duty vehicle (n=3)	2,934	40	35	57
Port cargo truck (n=2)	0	87	50	50
School bus (n=3)	92	77	120	47
Transit bus (n=1)	2,300	145	300	2,000
TRU (n=1)	300	0 [b]	0 [b]	0 [b]

[a] Numbers of fleet managers who have vehicles in each market sector (shown in parentheses) total more than 12, because many fleets have vehicles from more than one sector.
[b] Based on observed EVs on site during site visit conducted by the Evaluation Team; the respondent inaccurately responded with the number of projected EVs.

Industry Perspective

Asked how well-positioned they thought their industry or sector was for electrification, half of the responding fleet managers reported being well-positioned, with one of 10 saying their industry was *extremely well-positioned* and four saying their industry was *somewhat well-positioned*, shown in Figure 74. One fleet manager reported being *not too well-positioned*, one fleet manager reported being *not at all well-positioned*, and three respondents reported their positioning as *neutral*. Those who did not think their industry was well-positioned mentioned EV's range limitations and higher weight than ICE vehicles, which can decrease shipping efficiency, requiring more vehicles to transport the same amount of product. Since EY2021, when four of six fleet managers rated their industry as *extremely well-positioned* or *somewhat well-positioned*, fleet managers' views on their industry's prospects for electrification have become more pessimistic each year up until EY2024, when six of 12 rated it as *not too well-positioned* and five of 12 rated it as *somewhat well-positioned* or *extremely well-positioned*.

Figure 74. SCE Charge Ready Transport Program Fleet Manager Positioning of Industry for Electrification in EY2025



Source: Fleet Manager Survey Question F1. "How well positioned do you think your industry/sector is for electrification?" (n=10)

The Evaluation Team asked fleet managers what they saw as the limitations of current EV options for their market sector. Three respondents mentioned the mileage range of available EVs as a major limitation. One respondent said that they experienced fewer financing or leasing options for EVs than diesel trucks. Finally, fleet managers were asked whether, given what they know or believe about requirements for fleets

to purchase zero-emission MDHD trucks, electric or diesel trucks seemed like a risker purchase in the next three years and the next 10 years. For the three-year projection five of 10 respondents said that electric trucks would be the riskier choice and five said diesel. For the ten-year projection, three respondents said that electric trucks would be the riskier choice and seven said diesel. This is a shift from EY2024, when a majority of fleet managers said that electric trucks would be a riskier choice in either scenario, 11 of 12 saying that electric trucks would be riskier in the next three years and seven of 12 saying that electric trucks would be riskier in the next 10 years.

Interview Results

The Evaluation Team interviewed two fleet managers who withdrew from the SCE Charge Ready Transport program. One fleet manager managed a fleet of school buses for a school district and the other managed MDHD vehicles for a state county.

The fleet manager for the school district explained that the district began electrifying its school buses around 2016, when it acquired the four electric buses that make up its current fleet. A need to replace aging diesel school buses and the environmental benefit of EVs motivated the school district to electrify. The other fleet manager was motivated to electrify the county fleet by state electrification mandates and their ability to leverage their existing infrastructure. This fleet manager had already completed several electrification projects through the Charge Ready Transport program.

Asked about their main reasons for withdrawing from the Charge Ready Transport program, the school district fleet manager said that the cost to electrify the four buses they had committed for the program was too high and that they still had plans to acquire two electric buses outside the program for their fleet. The county had withdrawn its application for one site because its proximity to an airport was causing an issue with the Federal Aviation Administration. The county reapplied to the Charge Ready Transport program for another location nearby to fulfill the same needs.

Overall, both fleet managers were very happy with the program, withdrawing each of their projects due to factors outside of program implementation. Each provided additional feedback on individual aspects of the program as well. The school district fleet manager applauded the effort put in by SCE staff for the site prior to withdrawal, saying that SCE staff, "tried very hard to work for us." Both fleet managers said that they were very satisfied with the application process and timeline. The county fleet manager mentioned experiencing project delays and communication challenges with SCE staff related to the site easements.

Fleet managers indicated that program incentives played a supportive but non-decisive role in site implementation. One fleet manager said that they were "nice, but not critical" and the other said that the incentives were "helpful, [but] not substantial." In addition to the Charge Ready Transport incentives, the school district also used grants to pay for their electrification activities.

Highlights

- Surveyed fleet managers were motivated to participate in the Charge Ready Transport program primarily by regulatory requirement (8 of 10), environmental benefits (7 of 10), and rebates/incentives (7 of 10).
- Top barriers to fleet electrification before program participation included the cost of EVs (7 of 10) and the cost of EV charging infrastructure (7 of 10). After program participation, the cost of EVs remained a top barrier (5 of 10).
- Nine of 10 responding fleet managers rated themselves as *very satisfied* or *somewhat satisfied* with their experience with the Charge Ready Transport program.
- Six of nine responding fleet managers learned about the Charge Ready Transport program from SCE.
- Nine of nine fleet managers said that their charging equipment was *very reliable* or *somewhat reliable*, and seven of nine said that their EVs were *very reliable* or *somewhat reliable*.
- Seven of eight responding fleet managers said they practiced load management with their fleets.
- Five of 10 responding fleet managers planned to accelerate EV and EV charging equipment procurement due to their experience with the program.
- Five of 10 responding fleet managers said they thought their industry or sector was well-positioned for electrification.
- One fleet manager who withdrew from the program said they could no longer commit to purchasing the required number of EVs, and the other had location permitting issues.

Site Visit Findings

For EY2025, the Evaluation Team completed 37 Charge Ready Transport program site visits in the SCE territory across several market sectors: heavy-duty vehicle (including port cargo and drayage), medium-duty vehicle, school bus, transit bus, and TRU. These included visits to sites that were activated in EY2024 but that were not available for site visits until EY2025. During the site visits, the Team collected qualitative and quantitative information about fleet composition and operations. Site visits were used to verify basic information about sites such as quantity and capacity of installed charging equipment, the NSPs the fleets use, types and quantities of EVs in use or scheduled for delivery, and physical influences on construction designs.

Table 32 provides a summary of site characteristics by market sector, including number of sites visited, number of L2 and DCFC ports, and total charging capacity. In total, the SCE Charge Ready Transport program sites visited in EY2025 added 445 ports with just over 40.5 MW of EV charging capacity. Figure 75 is a visual representation of Table 32, showing charging port and charging capacity of Charge Ready Transport program site visit locations by market sector for EY2025 and the program to date.

Table 32. SCE Charge Ready Transport Program Quantity of Ports by Type and Installed Capacity, by Market Sector

Market Sector	Sites Visited in EY2025 [a]	EY2025 Sites Ports [a]	EY2025 Sites Capacity (kW) [a]	PTD Sites Visited	PTD Sites Ports	PTD Sites Capacity (kW)
Forklift	0	0	0	1	7	417
Heavy-Duty Vehicle	19	192	28,656	40	692	92,363
Medium-Duty Vehicle	7	101	5,056	18	314	13,920
School Bus	6	93	2,574	38	374	8,611
Transit Bus	3	12	3,490	9	68	8,038
TRU	2	47	747	6	269	7,520
Totals	37	445	40,523	112	1,724	130,869

[a] Counts of site visits represent sites visited in EY2025, some of which were activated in EY2024 but were not available for site visits until EY2025. This difference in timing causes higher values for sites visited in this table than in others in this report.

Figure 75. SCE Charge Ready Transport Program Site Visit Ports and Capacity, EY2025 and PTD Sites

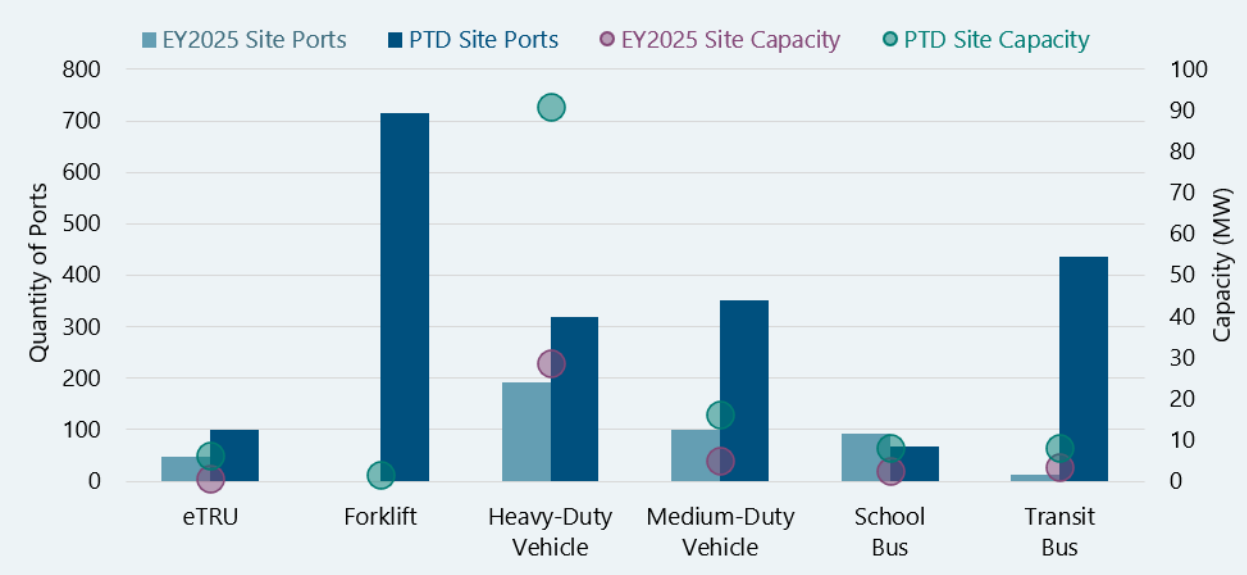
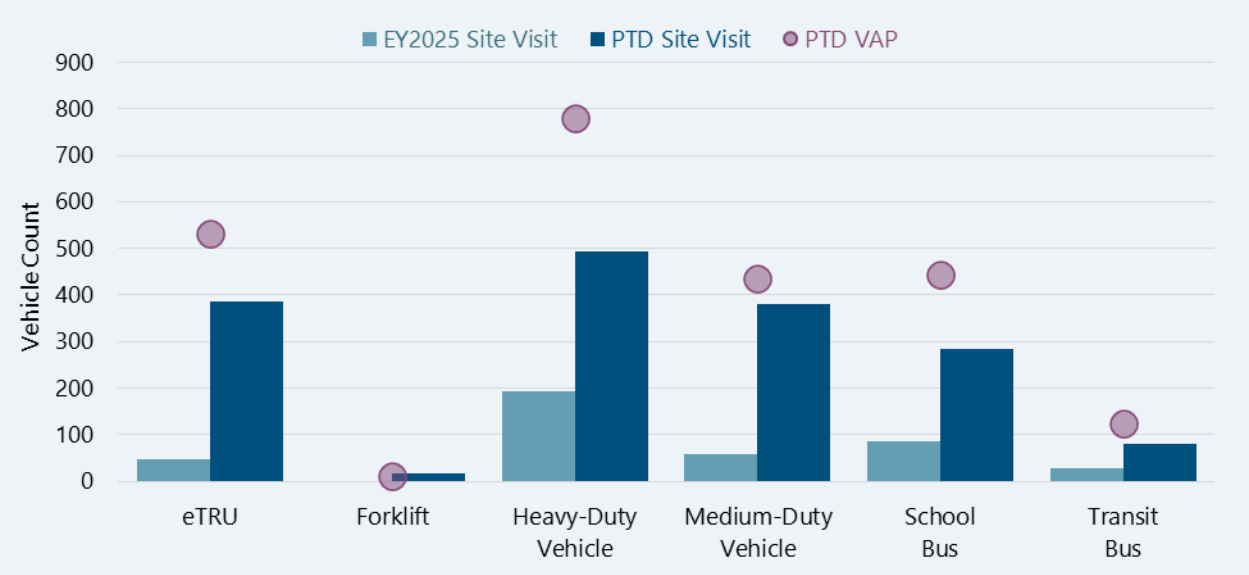


Figure 76 shows the counts of vehicles noted through site visits compared with the counts in long-term VAPs. Market sectors closest to plan include heavy-duty vehicle, medium-duty vehicle, and forklift. In general, the divergence between the number of observed vehicles and the total number of vehicles in long term VAPs in Figure 76 is expected, as the Evaluation Team visits each site only once and does not maintain an updated count of vehicles for sites activated in previous years. As a response to a recommendation in the EY2023 Evaluation Report, SCE has implemented a process to follow up with each participating fleet on an annual basis to update the number of delivered EVs and adjust future planned deliveries to meet the numbers of EVs specified in the VAPs.

Figure 76. SCE Charge Ready Transport Program Comparison of Verified Vehicles to Long-Term VAP



Site visits also allowed the Team to understand fleets' level of familiarity with their energy use and costs for EVs compared with conventional vehicles and their use of load management to mitigate utility bills. During these visits we discussed potential funding sources beyond Utility investment and investigated whether fleets had an interest in on-site solar and/or battery storage. Site visits also provided an opportunity to obtain direct feedback from the individuals involved in these projects from inception through construction and operations.

The following sections provide a summary of key observations and data collected during site visits, organized by market sector.

Common Site Visit Findings Across Utility Programs

Like in EY2024, the Evaluation Team continued to see charging sites that supported multiple fleets, including large truck stop–type sites, vehicle dealer sites, and other sites that offer public charging.

Dealerships continued to participate in SB 350 programs across the state, with some constructing multiple sites. Dealerships offer charging to dealer operated vehicles and rental vehicles, and some make the site available to neighboring fleets. Several operators of other types of fleets also participated in one or more Utility programs to construct multiple sites. Most of these fleets replicated the same infrastructure from site to site, while others modified the site design based on regional demand.

Fleets across all market sectors continued to express concerns over the long-term viability of vehicle OEMs, NSPs, and EVSE manufacturers.

Many fleet managers reported that they do not know how much they spend on utility bills for charging EVs or how these costs compare with the costs of using conventional fuels. They were also not sure whether reducing the cost of charging would be possible. Some of these fleets participated in a deep dive

interview that examined the barriers to fleets implementing load management, which would allow them to shift some of their EV charging to periods of low-cost electricity. A summary of these interviews is located in the *Statewide* section of this report.

Heavy-Duty Vehicle

In EY2025, the Evaluation Team conducted site visits to 19 heavy-duty vehicle Charge Ready Transport program sites, which had a total of 192 charging ports and a total installed capacity of 28.6 MW. The SCE territory has the highest count of Class 8 electric trucks of any utility territory in the state.

Many heavy-duty sites the Team visited, and a large portion of total installed capacity were for logistics providers. This market sector, which also includes vocational vehicles, typically had 500 kWh or more of battery capacity per truck. Some operators made use of large batteries and higher-capacity DCFC charging (>150 kW) to run multiple charging shifts per day. Of the fleet managers who were aware of load management, multi-shift operators explained that load management becomes difficult as daily shifts increase which leaves less flexibility for charging. However, as shown in *Grid Impacts* billing details, even without load management, monthly bills for high-usage sites may have lower average costs per kilowatt-hour, as vehicles often charge during both on- and off-peak times in a single day.

The Evaluation Team observed a few heavy-duty sector sites that had more vehicles than EVSE. These sites often had a scheduler or valet to help prioritize charging and ensure that vehicles remained mobilized. The CaaS providers noted that their charging utilization had to do with fluctuating market demand, including customer-fleets using their sites while the customer completed their own long-term charging installations elsewhere.

The Team also visited several sites with solar arrays (500 kW to almost 2,000 kW) and energy storage (1 MWh to 10 MWh).

During the heavy-duty vehicle site visits, the Team observed eight different OEM brands of chargers: half of these were legacy manufacturers and half market entrants (Figure 77 shows a photograph taken during one of these site visits). Both 180 kW and 360 kW models are seeing widespread adoption. One site was equipped with Megawatt Charging System (MCS) chargers capable of up to 1,200 kW, although these had not been activated as they were pending inclusion on the Approved Products list. One heavy-duty OEM and other medium-duty and component suppliers recently declared bankruptcy, which could create procurement challenges for some fleets. Some heavy-duty sites had leased charging infrastructure and or their vehicles, which included service agreements. These fleets reported that the dealer or manufacturer for the leased vehicles often responded quickly when trucks experienced issues unlike for vehicles that were owned outright.

Figure 77. SCE Charge Ready Transport Program Heavy-Duty First Instance of Megawatt Chargers at CaaS location



Medium-Duty Vehicle

In EY2025, the Evaluation Team conducted site visits to seven medium-duty vehicle sites, which have 101 charging ports and a total installed capacity of 5.1 MW. Interesting examples of this market sector consisted of dealerships, fleet-based public charging, and big-box store customer rental vans and trucks.

The Evaluation Team visited one dealer group with two sites that used the same equipment; had very similar layouts; and faced challenges in construction, commissioning and operation. Both sites used standard power cabinets and dispensers and DCFCs with integrated energy storage. Each had a simultaneous charging capacity of over 1.2 MW while only connected to the grid at 500 kW, which was possible through integrated battery systems. Both experienced delays from multiple rounds of design revisions between the TTM and BTM sides, and for switchgear delivery, followed by challenges in commissioning hardware from a bankrupt manufacturer. To meet requirements from other grants, the fleet had ordered hardware in 2022, which was delivered in 2023 but not installed until late 2024 and commissioned in 2025.

The dealer had intended to offer charging as standalone service or as part of truck packages; however, the removal of the ACF regulation for private fleets reduced both overall truck sales and the need for small fleets to use dealer-based charging centers. The stations to date have mostly charged dealership mobile service/parts delivery vehicles and some customer vehicles when in for service. This is much lower utilization than the sites expected when planning their projects.

A big-box retailer provided 20 L2 charging ports to support overnight charging of delivery and rental vans (Figure 78). These vans are operated by a third party or by customers, which may limit the site host's ability to implement load management over the vehicle charging.

Figure 78. SCE Charge Ready Transport Program Medium-Duty Delivery Truck Available for Rent or Lease



Transportation Refrigeration Unit

In EY2025, the Evaluation Team conducted site visits to two TRU sites with a total of 47 ports and nearly 750 kW of installed charging capacity installed to satisfy ACF and warehouse-oriented regulations. One of these sites had installed an island with make-ready infrastructure for TRUs during a previous capital building phase outside of the SCE program. Since then, the fleet had realized two issues with this installation. The first is that the site preferred TRUs to be connected at loading docks. The second issue, which was evident many years after the installation is that capacity (existing service and on the BTM facility) was no longer available from the utility.

A third heavy-duty vehicle site also had TRU ports that predated the Charge Ready Transport program site. Figure 79 shows an example of a TRU charging site.

Figure 79. SCE Charge Ready Transport Program Charging Island Supporting TRU and Truck Charging



School Bus

In EY2025, the Evaluation Team conducted site visits to six school bus sites representing 93 ports of which more than two-thirds were DCFCs. In total these sites had installed 2.6 MW of capacity. Three sites were subsequent phases to earlier Charge Ready Transport sites varying in scope from two to 20 ports. The Team discussed the use of V2G with each of these fleet operators and found that none knew the financial value of or had plans to implement this feature. School district fleets expressed a desire to build partnerships with other school districts to increase the length of trips their electric buses could handle, such as for field trips of school sports events. Schools are trending toward lower-power DCFCs (30 kW) instead of higher-power L2 (16.5 kW) chargers seen in previous years.

Transit Bus

In EY2025, the Evaluation Team visited two operators, one of which was very large and the other very small, with very different installed charging infrastructure. The large transit operator managed two sites used for opportunity charging: a transit station with four 450 kW overhead pantograph chargers and an adjacent bus depot with four 360 kW overhead pantograph chargers, as shown in Figure 80. These two projects support the electrification of more than 30 BRT buses. A large gantry system is also under construction at the bus depot as two separate Charge Ready Transport program sites. Each site consists of twenty 180 kW power cabinets, with each cabinet serving three pantographs or ports, for a total of 120 ports across the two sites. SCE has worked closely with the transit agency to bring in enough power for each phase and will build a 10 MW substation on site to support the full build out. The second small transit operator installed four ports totaling 250 kW.

Figure 80. SCE Charge Ready Transport Program
Electric Bus at Pantograph-Down Charging Station



Highlights

- In 2025, 19 of 37 sites were heavy-duty vehicle sites, which had total installed capacity of 28.6 MW. Most Class 8 electric truck deployments across the state are in SCE territory. This market sector typically had around 500 kWh of battery capacity per truck, and the sites in this sector use higher-power DCFC charging (>150 kW).
- School bus sites continued electrification trends; three of the six site visits covered sites that included a second phase to expand electrification of their fleets. Schools are trending toward lower-power DCFCs (30 kW) instead of higher-power L2 (16.5 kW) chargers.
- Medium-duty vehicle dealers have built charging to serve their own vehicles as well as their customers' vehicles; however, regulatory and market changes have negatively impacted anticipated EV adoption and infrastructure utilization.
- Heavy-duty vehicle, TRU, and school bus sites have a more significant gap than medium-duty vehicle and transit bus sites between long-term VAPs and vehicles observed on site.

Deep Dives

The Evaluation Team conducted deep dives for three Charge Ready Transport fleets in EY2025. The Team considered sites with significant demand, energy consumption, or installed charging capacity; sites that had an ability to expand EV infrastructure; sites with load management, unique vehicles or charging equipment, a large fleet; and importantly, sites with a fleet manager who was willing to participate in the deep dive process.

The three selected heavy-duty vehicle Class 8 fleets operate sites that were completed in 2024. As part of the deep dives, the Team conducted in-depth fleet manager interviews, analyzed AMI and EVSP data, and developed fleet driver surveys. While all three fleets were open to interviews and discussion of their Charge Ready Transport projects, only one of the three fleets participated in the driver surveys.

Findings presented in this section reflect the results of the interviews, the data analysis, and driver survey feedback. *Appendix A* presents detailed case studies on each of these fleets.

Fleet 1: Heavy-Duty Freight Operator

The Evaluation Team selected the first fleet, which operates Class 8 trucks, for a deep dive analysis because of the fleet's three Charge Ready Transport sites in SCE territory, the extremely high energy throughput of two of the sites, and the fleet's policy of open access to other fleet operators and the public despite being a single-fleet-focused installation. Table 33 illustrates the key characteristics of the individual sites.

Table 33. SCE Charge Ready Transport Program Heavy-Duty Fleet 1 Site Characteristics

Site	Chargers	Vehicles	Unique Site Characteristics	Installed Site Capacity
1	13x 360 kW PhiHong	14x Nikola 10x BYD 5x Volvo Unspecified # Tesla	Drayage operation	5 MW
2	12x 360 kW PhiHong		Second phase built due to significant demand and extremely high usage	4.3 MW
3	6x 360 kW PhiHong		Low utilization (~400 kW)	2.2 MW

The fleet's vehicles move between each of the three sites based on need and duty cycles, charging based on opportunity and availability. The SCE Charge Ready Transport program directly supports 48 battery-electric Class 8 tractor-trailers comprising Nikola, BYD, Volvo, and Tesla models, but the fleet operates a total of 75 vehicles across all of its sites within California. Across all of its California sites, the fleet estimates its EVs drive approximately 100,000 miles per week, necessitating quick, reliable charging with available redundancy. Each SCE Charge Ready Transport site operates 360 kW PhiHong dual-port DCFCs, with some of the fleet's sites in other territories using megawatt chargers. The fleet manager noted that the 360 kW PhiHong charging stations are used nearly nonstop which has resulted in stations overheating and showing reduced performance. Due to this high demand for charging and the overarching need for greater energy throughput, the fleet plans to transition to megawatt charging as soon as its vehicles can support the MCS standard.

The fleet manager noted that the fleet's charging policy no longer avoids charging during the 4 p.m. to 9 p.m. period, in favor of a "charge when needed" approach that prioritizes operational efficiency. Despite this change, the monthly percentage of energy consumed during the 4 p.m. to 9 p.m. period has remained at approximately 15%, which indicates that additional charging must be occurring outside of the 4 p.m. to 9 p.m. period; this is clearly supported by a doubling of overall monthly energy consumption between January and October of 2025 (from 580 MWh to 1,010 MWh across all three SCE Charge Ready Transport sites). The substantial increase in charging demand at the second site has created a charging bottleneck as vehicles are unable to charge quickly enough to accommodate other trucks waiting to charge. To combat this, the fleet installed a second phase of chargers outside of the program and also uses a nearby unaffiliated commercial charging installation to provide overflow charging.

The fleet manager expressed satisfaction with the diverse set of vehicles in the fleet, noting that overall reliability has been good and that the vehicle manufacturers resolve any issues that arise. The fleet has developed an internal engineering team to perform maintenance and repairs of one specific vehicle model manufactured by a company that is no longer operational, without having to involve a third party.

In addition to the three sites in SCE territory, the fleet operates one site in PG&E territory, covered in the PG&E *Deep Dives* chapter. This site, which was selected for a deep dive for the same reasons as the three SCE Charge Ready Transport sites, also incorporates solar generation and a battery bank to reduce charging demand during peak periods.

Fleet 2: Heavy-Duty Freight Operator

The Evaluation Team selected a heavy-duty freight fleet operating 14 Class 8 tractor trucks and six yard tractors for a deep dive based primarily on the site's usage of an ancillary solar and energy storage system to reduce charging demand on the grid during peak periods.

The 14 Class 8 trucks, which consist of Freightliner and Peterbilt models, are supported by 20 ABB Terra 184 DCFC ports installed as part of the SCE Charge Ready Transport program in the first of a two-part conventional grid-tied installation. The site also operates 18 ABB Terra 184 DCFCs fed by a 450 kW solar array tied to a 1 MWh battery. Both sides of the installation use automated load management to limit system demand during peak periods. Between 4 p.m. and 9 p.m., the fleet uses the solar-supported side for almost all of its charging and limits the grid-tied system charging to 5 kW per charging station, reinitiating after the peak period. Maintaining 5 kW charging ensures that connected vehicles' onboard computers keep their charging session active, allowing them to automatically resume higher-power charging once controls are lifted. This charging strategy results in extremely low energy usage from the grid during the peak period, with averages between 8% and 10% of the fleet's total energy use since the project's activation.

The fleet manager noted that operating more than eight trucks will usually fully deplete the energy storage system during the winter, with more reserve left in the battery during the summer due to the additional charging capacity coming directly from the solar installation. There is opportunity to add additional storage and solar utilization, with an estimated four to five hours of insolation being abated during the summer. Overall, the fleet uses the energy storage system for approximately 65% of the energy delivered to vehicles with the remaining 35% coming from the grid-tied charger installation.

The fleet manager described vehicle reliability as fair, with some early issues in 2023 that led to significant operator frustrations. These issues have since been resolved, but drivers remain wary of certain vehicles despite recent reliability much closer to that of the fleet's diesel trucks. The fleet's main restriction is now vehicle range, as routes cover the entire Southern California region. The fleet planned to address this issue by obtaining vehicles from the DOE SuperTruck 3 project; however, the fleet is considering its options in the wake of the DOE program's funding suspension.[54]

Fleet 3: Heavy-Duty Freight Operator

The Evaluation Team selected a heavy-duty freight fleet operating 40 Class 8 tractor trucks for a deep dive because of the fleet's use of electric transport refrigeration units (TRUs) and supporting charging stations, large deployment of tractor trucks, and use of solar photovoltaic (PV) and battery storage system.

The 40 Freightliner electric trucks at this site are used in a single shift, mostly operating on local routes of about 80 to 90 miles. The site installed 40 120 kW ABB Terra 184 dual-port DCFCs, operating on BP Pulse network software and maintains an operating ratio of one charger per truck. Chargers have been

[54] DOE SuperTruck 3 is a federal program aimed at improving the efficiency of alternative-fuel heavy-duty trucks, including hydrogen and battery-electric models. Grant funding for the program was terminated in October 2025.

moderately reliable, with documented issues by the fleet about charging sessions stopping on their own, necessitating staff to manually check on chargers to ensure that sessions are uninterrupted.

While the fleet previously operated six trailers equipped with TRU units charging on ESL TRU–specific chargers, the manufacturer of the TRUs ceased operations and removed their equipment from the trailers. The fleet manager reported an excellent experience with the TRUs while they were in use. The manager also spoke about the greatly improved reliability of the fleet's Freightliner trucks, citing the responsiveness and dedication of the local dealer as a critical component of this positive experience, and noting that the fleet's drivers love the vehicles.

The ABB DCFCs are supported by a 2 MWh battery storage system, coupled with a 1.5 MW solar PV system. The battery storage system primarily serves EV charging and is not used for on-site warehouses or other ancillary operations.

The fleet manager was not aware of plans to continue expanding the EV fleet, though they continue to examine opportunities to reintroduce TRU trailers into their fleet.

Fleet Driver Surveys

One of the three fleets in SCE territory opted into fleet driver surveys in EY2025. The Evaluation Team received a single survey, consisting of aggregated responses from an unspecified number of on-site fleet drivers. Drivers noted that they generally charge the vehicles overnight and, in the mid-afternoon, with improving vehicle reliability after an initial spate of problems. Overall, drivers were satisfied with the operation of their vehicles but cited range as an issue. Drivers cited the lack of exhaust fumes and improvement in comfort and convenience as benefits, and sporadic issues initiating charging sessions and long, difficult-to-handle cables as costs.

Highlights

- Two of the three deep dive sites supported their DCFCs using solar PV arrays and battery storage systems, resulting in very low percentages of energy consumption from the grid during the 4 p.m. to 9 p.m. period (5% to 10%).
- One fleet elected to abandon load management during the 4 p.m. to 9 p.m. period in favor of prioritizing consistent vehicle operations. However, the extremely high energy throughput across the fleet's operating hours has resulted in a comparable percentage of energy used between 4 p.m. and 9 p.m. as with load-managed sites.

Co-Benefits and Co-Costs

Through fleet manager surveys and deep dive fleet manager interviews, the Evaluation Team explored several co-benefits and co-costs associated with the SCE Charge Ready Transport program's vehicle electrification sites, as described below.

Fleet Manager Surveys

To assess co-benefits and co-costs, the fleet manager surveys used both aided (asking fleet managers if they expected a specific co-benefit or co-cost) and unaided (open-ended) questions.

For EY2025, 10 fleet managers completed the fleet manager survey. Table 34 shows that nearly all surveyed fleet managers expected to realize benefits for their community or fleet from electrifying in at least one category. Fleet managers expected the most significant benefits to accrue to their community, such as significant benefits from improved air quality (4 of 8) and from reduction in noise pollution (5 of 9). These results are similar directionally to results from EY2024, when 10 of 12 fleet managers expected significant benefits from improved air quality and health, and seven of 12 expected significant benefits from reduced noise pollution. In EY2021 through EY2023, the majority of fleet managers also expected significant benefits from the same categories and reported no benefits in only one or two categories in each of the years.

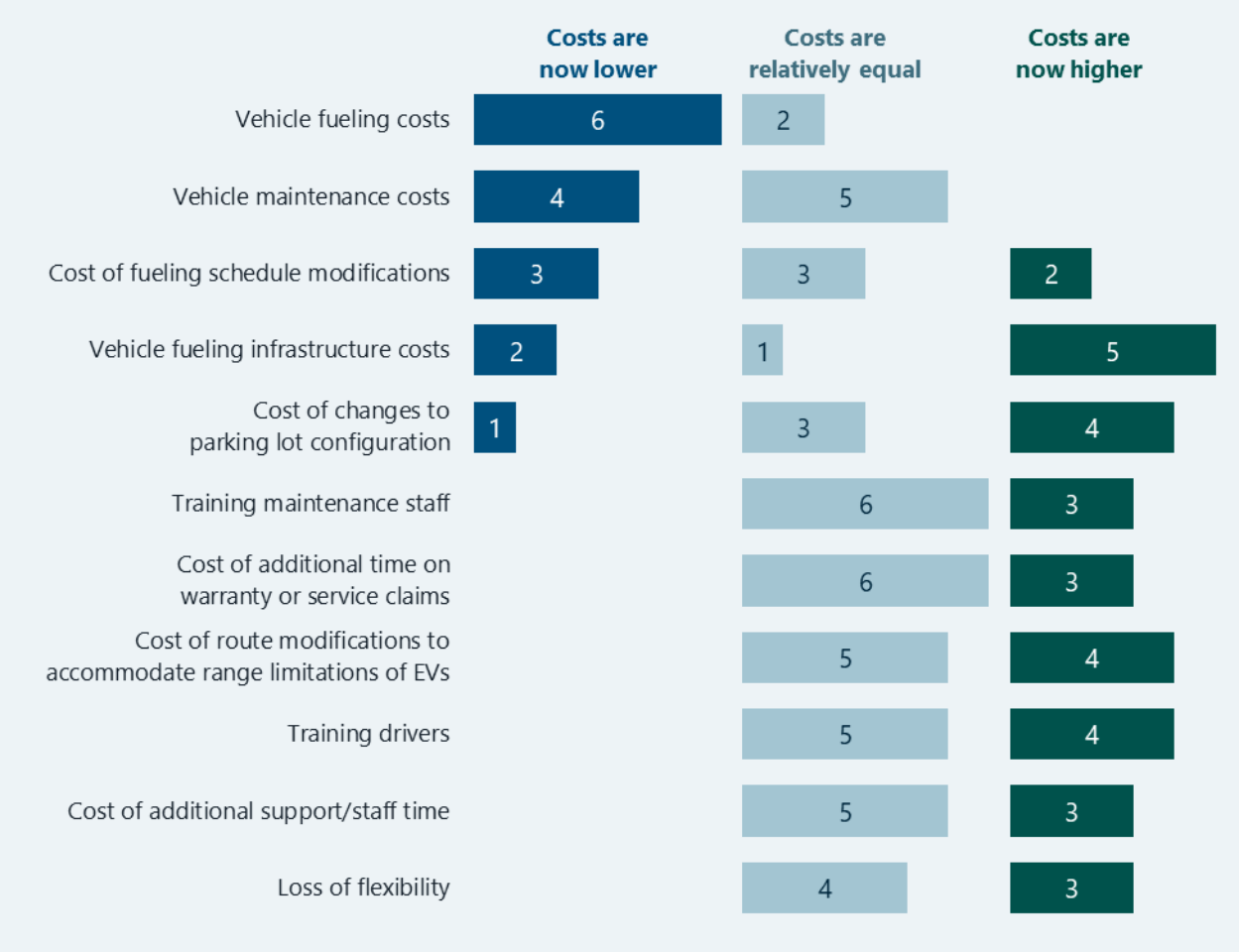
Table 34. SCE Charge Ready Transport Program Fleet Managers' Ratings of Benefits from Electrification in EY2025[a]

Benefits	Significant Benefits	Some Benefits	No Benefits
Encourages other individuals or fleets to convert to EVs	1	7	1
Improved air quality	4	3	1
Reduction in noise pollution	5	2	2
Improved driver/passenger comfort/convenience	2	4	3
Increased fleet flexibility	-	5	4

[a] Nine of the 10 fleet managers who completed the survey provided responses for the questions on benefits from electrification.

The Evaluation Team asked fleet managers to estimate how the costs associated with operating and maintaining their fleets have changed since electrification. As shown in Figure 81, six of nine fleet managers reported lower costs for vehicle fueling costs and four of nine observed lower vehicle maintenance costs. Five of nine fleet managers cited higher costs for the vehicle fueling infrastructure costs and four fleet managers each cited higher costs from changes to parking lot configuration, route modifications to accommodate range limitations of EVs, and training drivers. Many fleet managers estimated that their costs remained relatively equal across cost categories. These results are largely consistent with EY2021 through EY2024, when fleet managers estimated lower and higher costs for similar cost categories.

Figure 81. SCE Charge Ready Transport Program Observed Cost Changes since Electrification in EY2025

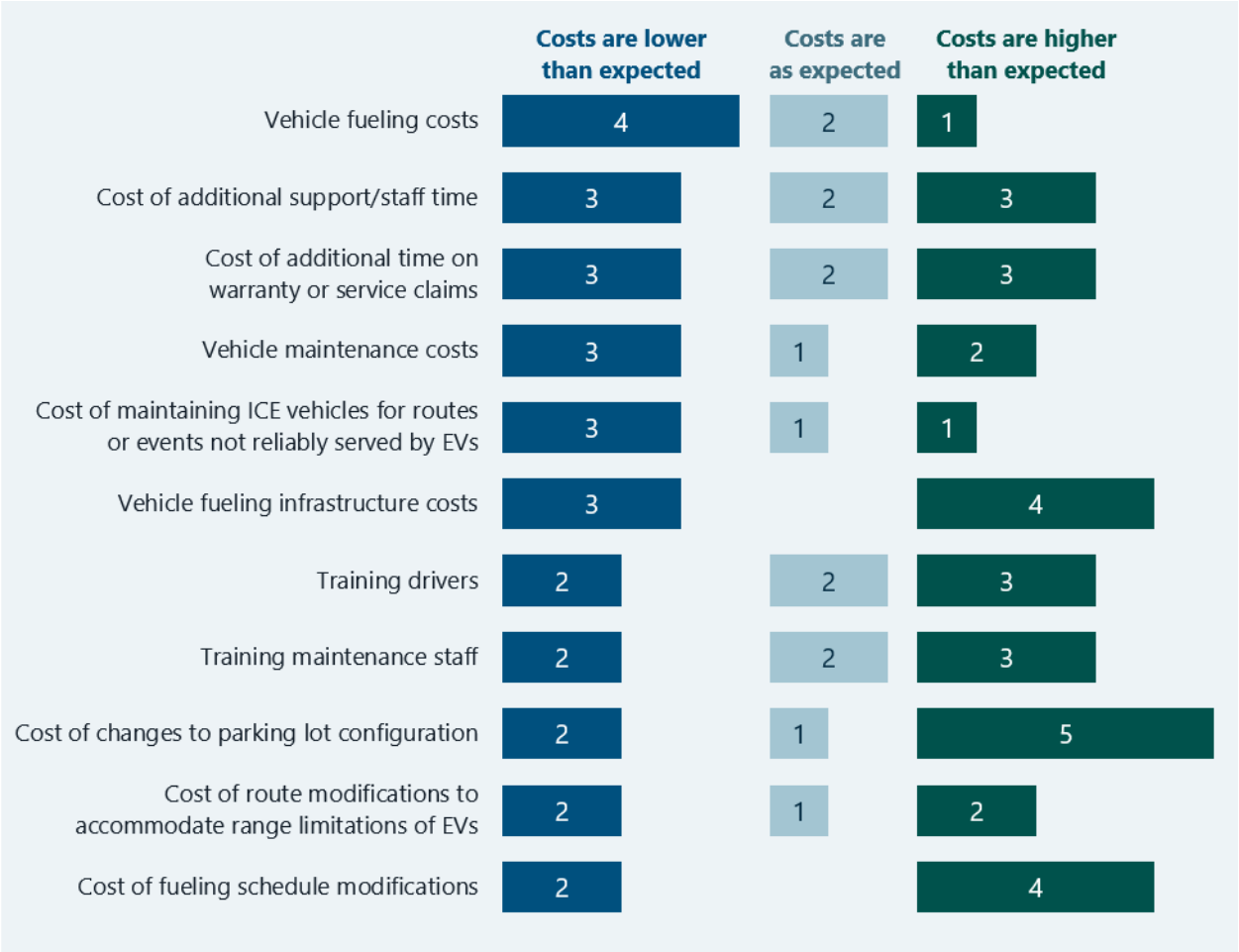


Source: Fleet Manager Survey Question E1. "Please think about all the costs associated with operating and maintaining your fleet. For each cost type, please estimate how much the cost has changed since transitioning your fleet to EVs." (n=9)

The Evaluation Team asked fleet managers to what extent they expected operational and maintenance costs to change. As shown in Figure 82, costs changed as expected for only one or two fleet managers across all categories of the eight who responded to the question. In contrast, several fleet managers reported costs as lower or higher than expected across all categories. Four of eight fleet managers reported that costs were lower than expected for vehicle fueling costs. Five of eight fleet managers reported that costs of changing parking lot configurations were higher than expected. These results differ substantially from EY2024, when no fleet managers reported experiencing lower-than-expected costs, and from earlier years when few said they had experienced lower-than-expected costs. In contrast, fleet managers have not reported similar rates of higher-than-expected costs since EY2022 when two of four respondents reported that costs were higher than expected in three categories and one of four respondents reported higher-than-expected costs in five other categories.

Fleet managers mentioned other costs they incurred as a result of electrifying, with one fleet manager reporting additional "tire cost" and another citing "employee labor and safety."

Figure 82. SCE Charge Ready Transport Program
Differences between Electrification Expectations and Costs in EY2025



Source: Fleet Manager Survey Question E2. "Have these operational and maintenance costs been what you expected?" (n=8)

Deep Dive Fleet Manager Interviews

The Evaluation Team conducted deep dive interviews with three participating fleet managers to assess the co-costs and co-benefits of transportation electrification for fleets and drivers. During the interviews, fleet managers noted the following benefits and challenges:

- **EV reliability is a challenge, but manufacturers are consistently helpful.** Two of the surveyed fleet managers reported initial problems with keeping their EV fleet fully operational, due to a combination of software, electrical, and hardware issues. However, both respondents noted that EV manufacturers were responsive and helpful in addressing issues and minimizing downtime, which ultimately resulted in a significantly more stable and reliable experience. One fleet manager

described their experience with their local dealer, which had technicians on site for several months to diagnose and resolve a recurrent issue.

- **Dangers of obsolescence.** One fleet manager encountered issues with a manufacturer pulling out of the electrified market; this resulted in the abandonment of six dedicated ports at their facility with few other offerings within that particular market sector. The Evaluation Team has observed similar situations across utility jurisdictions and evaluation years.
- **Matching battery size with charging speed.** As vehicle batteries increase in size to increase vehicle operational range, vehicles require both higher-power onboard chargers and higher-power charging stations to minimize vehicle downtime. One fleet manager reported that the site is experiencing extremely high usage and congestion at the chargers, which serve mostly large-battery Class 8 tractor trucks, and plans to upgrade from 350 kW chargers to 1 MW chargers once more vehicles are capable of accepting the MCS standard to facilitate more turnover.

Highlights

- Eight of 10 surveyed fleet managers anticipated benefits for their community or fleet through the transition to electrification.
- Five of nine fleet managers expected significant benefits from reduced noise pollution and four of nine expected significant benefits from improved air quality.
- Six fleet managers reported lower costs for vehicle fueling costs since electrification and four reported lower vehicle maintenance costs. Five fleet managers reported higher costs for vehicle fueling infrastructure.
- Four of eight fleet managers reported lower than expected vehicle fueling costs and five of eight said that the cost of changing parking lot configuration was higher than expected.
- Despite reliability and battery size concerns, as well as the possibility of manufacturer obsolescence, the three deep dive interviews with fleet managers uncovered optimism for the future based on their overall interactions with manufacturers and local dealers.

Site Costs

The Evaluation Team conducted an analysis on 75 sites with fully closed out finances as of December 31, 2025, including sites activated in EY2021 through EY2025.[55] The set of fully closed out sites is smaller than the set of activated sites because of the time lag involved in performing activities such as collecting receipts, paying invoices, and obtaining administrative approvals. Cost estimates presented here are in nominal dollars.

The 75 sites had a mix of L2 and DCFC ports, with an average of 1,033 kW of installed capacity and 18.1 ports per site. The 75 sites included 28 school bus sites, nine transit bus sites, nine medium-duty

[55] The Evaluation Team received financial cost information for the 76 closed-out sites in 2025. However, one site operates with induction chargers which is unique to all other sites in the analysis and thus is excluded from the following site costs.

vehicle sites, 16 heavy-duty vehicle sites, five port cargo truck sites, six TRU sites, one forklift site, and one cargo handling equipment site. Of these 75, 13 sites had customer-owned BTM infrastructure; the remaining 62 had utility-owned BTM infrastructure. Market sectors are grouped together in this report to meet customer confidentiality requirements. While this aggregation masks findings for certain market sectors, it allows the Team to provide insights into the relative magnitude of costs faced by MDHD fleets. For a discussion of site costs by market sector, see the *Statewide* chapter.

Figure 83 shows the distribution of site-level costs for the 75 sites. The horizontal lines of the boxes show the 25th, 50th, and 75th percentile of sites; the X denotes the mean site cost; and the three panels are defined as follows:

- **Utility Infrastructure Costs.** Actual site installation costs borne by the Utility for both TTM and BTM (or the BTM incentive when the site infrastructure is customer-owned), including all capital and labor costs.[56] This does not include the cost of the EVSE equipment or installation.
- **Ratepayer-Funded Costs.** Actual site installation costs borne by the Utility, including all capital and labor costs of TTM, BTM (or the BTM incentive if the site infrastructure is customer-owned infrastructure), and EVSE rebate.
- **Estimated All-In Costs.** Estimated costs of installing the site borne by the Utility and the customer including all capital and labor costs. The value is calculated by summing actual TTM,[57] actual or estimated BTM,[58] and estimated EVSE costs.[59]

[56] Utility Infrastructure costs are the same as the Ratepayer-Funded Costs, except they do not include the EVSE rebates.

[57] The Utility pays 100% of the TTM costs and therefore reports actual TTM costs to the Evaluation Team.

[58] The Evaluation Team receives actual BTM costs for sites with Utility-owned BTM. In total, 61 of 75 sites with fully closed out financials have Utility-owned BTM. Other BTM costs were estimated by the Evaluation Team using the relationship between installed kilowatts and BTM from other sites with actual BTM costs.

[59] Because the Utility does not record actual EVSE costs, the Evaluation Team estimates all-in EVSE equipment costs using assumptions of $3,000 per port for L2 ports and $45,000 per port for DCFC ports.

Figure 83. SCE Charge Ready Transport Program Per-Site Costs Organized by Three Perspectives, Across 75 Closed-out PTD Sites

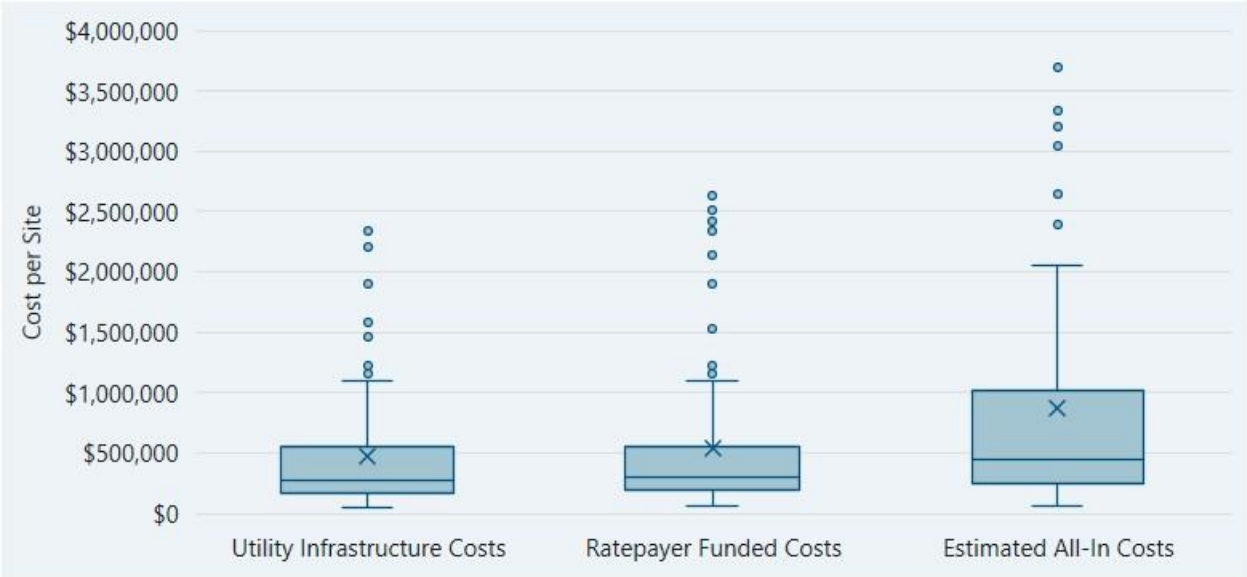
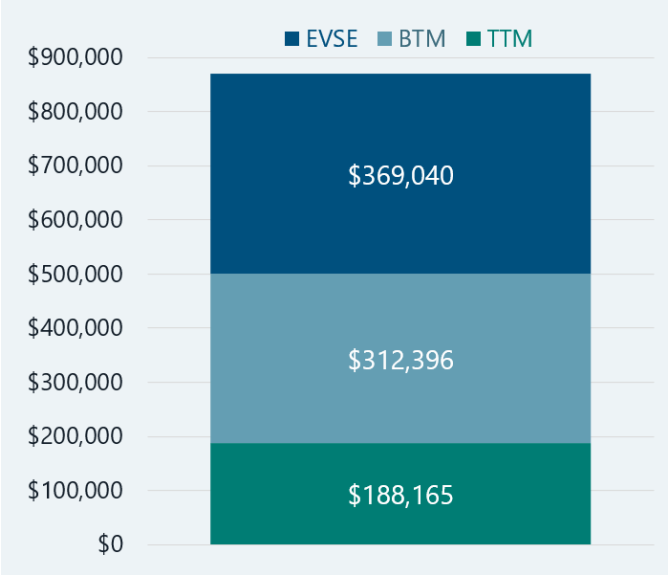


Figure 84 shows average estimated all-in costs for the 75 PTD sites. EVSE accounts for the largest cost across the sites, followed by BTM, then TTM. Together, the average all-in TTM, BTM, and EVSE cost is $869,600 through 2025.

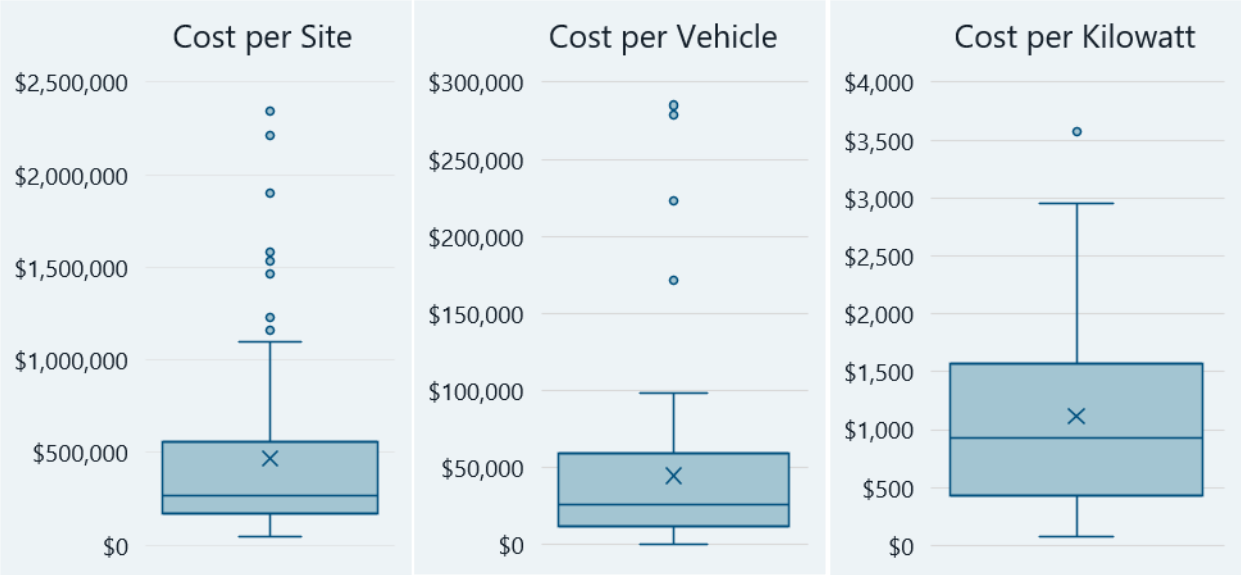
Figure 84. SCE Charge Ready Transport Program Average All-In Costs, Across 75 Closed-out PTD Sites



Source: The Evaluation Team calculated the costs shown in this figure by summing all TTM, BTM, and EVSE costs borne by SCE and the customer and dividing by 75 sites. Sites with customer-owned BTM have synthesized BTM costs.

Figure 85 shows the distribution of utility infrastructure costs (corresponding to the far-left panel of Figure 83) presented per site, per vehicle, and per kilowatt. The average utility infrastructure cost, including TTM and BTM borne by SCE through 2025, was $467,715 per site, $44,782 per vehicle,[60] and $1,119 per kilowatt of installed charging capacity. Although not shown, nearly 68% of Charge Ready Transport program spending on infrastructure for financially closed out sites to date has been on DAC sites, exceeding the 40% program target.

Figure 85. SCE Charge Ready Transport Program, Utility Infrastructure Cost per Site, per Vehicle, and per Kilowatt for 75 Closed-out PTD Sites



Highlights

- Estimated all-in costs paid by the customer and SCE vary widely between sites, with an average per PTD site of $869,600.
- The average utility infrastructure cost, including TTM and BTM, borne by SCE through 2025 was $467,715 per PTD site, $44,782 per vehicle, and $1,119 per kilowatt.
- Nearly 68% of Charge Ready Transport program spending on infrastructure for financially closed out sites to date has been on DAC sites, exceeding the 40% program target.

Grid Impacts

This section describes grid impacts for the SCE Charge Ready Transport program based on our analysis of energy consumed and customer bills by operational charging stations installed through the program in EY2025.

[60] Vehicle count is taken from the site's VAP.

Data Sources

The primary data source for the analyses detailed in this section is energy usage data provided in regular 15-minute intervals from the AMI. Other data sources include customer bills, LCFS program information, and charging session–specific data provided by NSPs. There are several important differences between AMI and NSP data. While AMI data reflect only energy usage, NSP data include session start and stop times, the duration of a vehicle's connection to a charging port, the duration of a vehicle actively pulling power, and the specific port and port data used for a session. An AMI meter does, however, track standing loads (such as those the EVSE uses for communications, cooling, active power converters, solenoids, and screens), which NSPs typically cannot do. When AMI data are missing from the dataset, the Evaluation Team uses NSP data to fill the gaps.

Summary of Grid Impacts

Table 35 presents the estimated SCE Charge Ready Transport program grid impacts.

Table 35. SCE Charge Ready Transport Program Grid Impacts

Impact Parameter	Actual 2025 [a]	Actual PTD	10-Year Projection PTD
Operational Sites	29	115	115
Installed Capacity (MW)	30	131	131
Electric Energy Consumption, MWh			426,082
On-Peak MWh 4 p.m. to 9 p.m. (and %)			N/A
Maximum Demand, MW (with date and time)	20.0 (8/29/25 9:30 p.m.)	20.0 (8/29/25 9:30 p.m.)	N/A
Maximum On-Peak Demand, MW (with date and time)	15.7 (7/24/25 4:15 p.m.)	15.7 (7/24/25 4:15 p.m.)	N/A

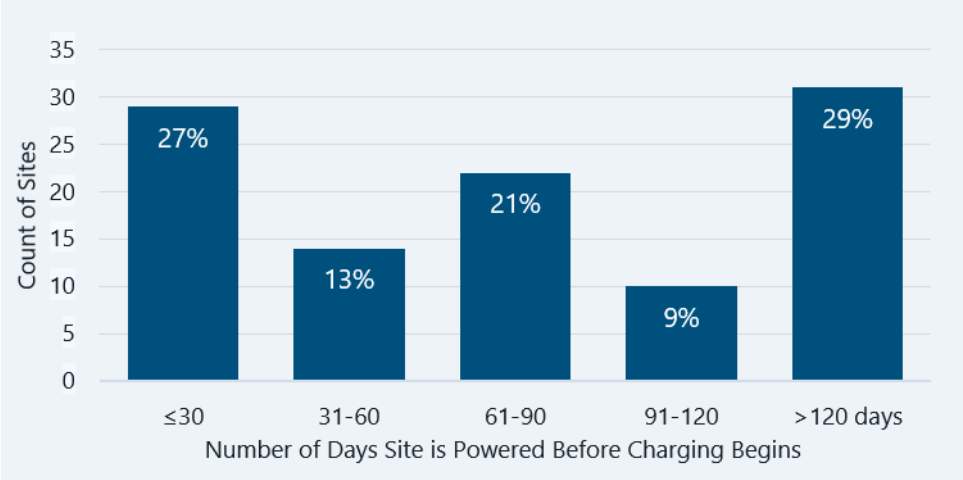
[a] Energy consumption, peak consumption, and demand data are based on PTD activated sites for calendar year 2025.

Energy Trends

Site Startup

The Evaluation Team examined the duration between Charge Ready Transport program site activation and operation to illustrate the relationship between readiness of charging infrastructure and actual vehicle charging. AMI data demonstrate that approximately 60% of sites were operational within 90 days of activation, as illustrated in Figure 86. However, as the final column of the figure shows, 35% of sites were not in use for at least four months after activation. Based on discussions during site visits, the Team found that the primary cause of delays in operation was a delay in vehicle delivery. Additionally, transit operators often took several months to commission vehicles. While not shown in Figure 86, fewer sites fell in the outer extremes of timeline between activation and operation in EY2025 than in previous years, with only 2% of sites operational within 30 days of activation and only 4% taking over 120 days, compared with 28% and 35%, respectively, in the pilot to date.

Figure 86. SCE Charge Ready Transport Program Percentage of Sites by Days between Activation and Operation for PTD Sites



Consumption and Maximum Demand

Figure 87 depicts the growth of SCE's monthly energy consumption and maximum demand for all operational sites in the Charge Ready Transport program to date. In EY2025 both consumption and maximum demand increased with older sites increasing operations and new sites becoming operational.

Charge Ready Transport program sites have an installed capacity of 131 MW and collectively reached over 20 MW of maximum demand at the end of 2025. As detailed in *Site Visit Findings*, the low demand relative to the installed capacity can be attributed to several factors, including fleet operators still gaining experience with new vehicles, waiting for delivery of vehicles, and not yet having commissioned all vehicles; charging infrastructure capable of delivering more power than vehicles are capable of receiving; slow growth in utilization; and reliability of vehicles and charging equipment.

Figure 87. SCE Charge Ready Transport Program
Monthly Energy Consumption and Maximum Demand

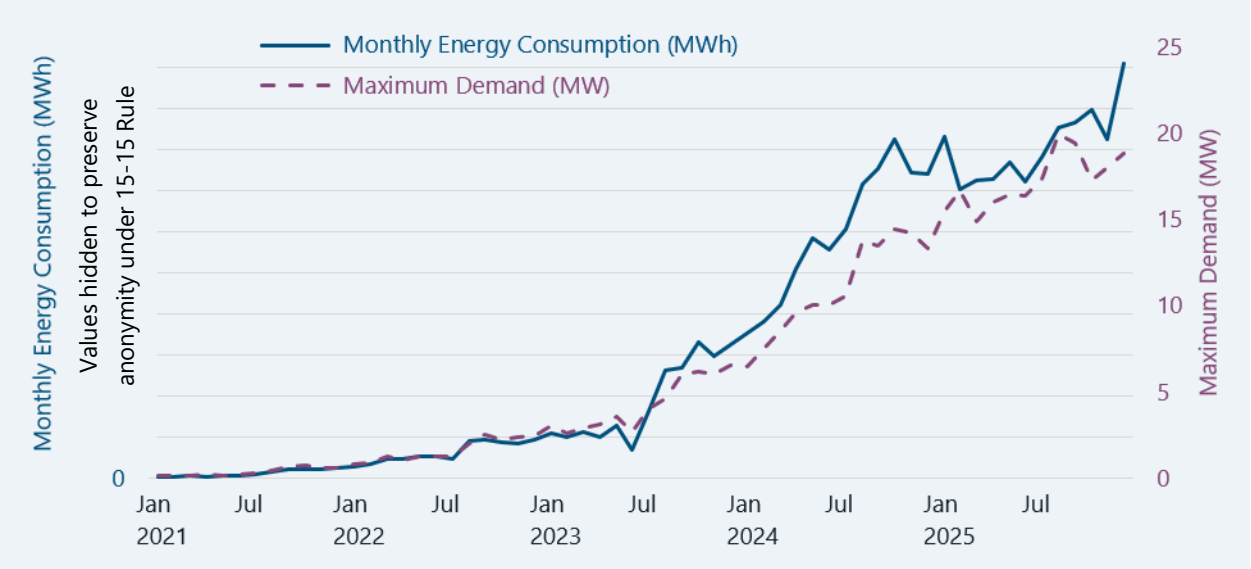


Figure 88 provides insight into energy consumption trends of activated sites by program reporting year. This perspective may allow analysis of operational maturity by site age. As a reference, the number of sites activated in each year was EY2021 (24), EY2022 (15), EY2023 (16), EY2024 (31) and EY2025 (29). Significant growth in monthly consumption can be seen within each year; however changes in energy consumption varies widely between evaluation years, with the most rapid growth occurring for EY2024 sites. Notably, monthly energy consumption increased less in EY2025 than in the previous two years even though the number of activated sites was similar in EY2025 and EY2024. This is due to multiple heavy-duty vehicle sites coming online at the same time as heavy-dury vehicle deliveries in early 2024.

Figure 88. SCE Charge Ready Transport Program Monthly Energy Consumption of Activated Sites Grouped by Initial Reporting Year

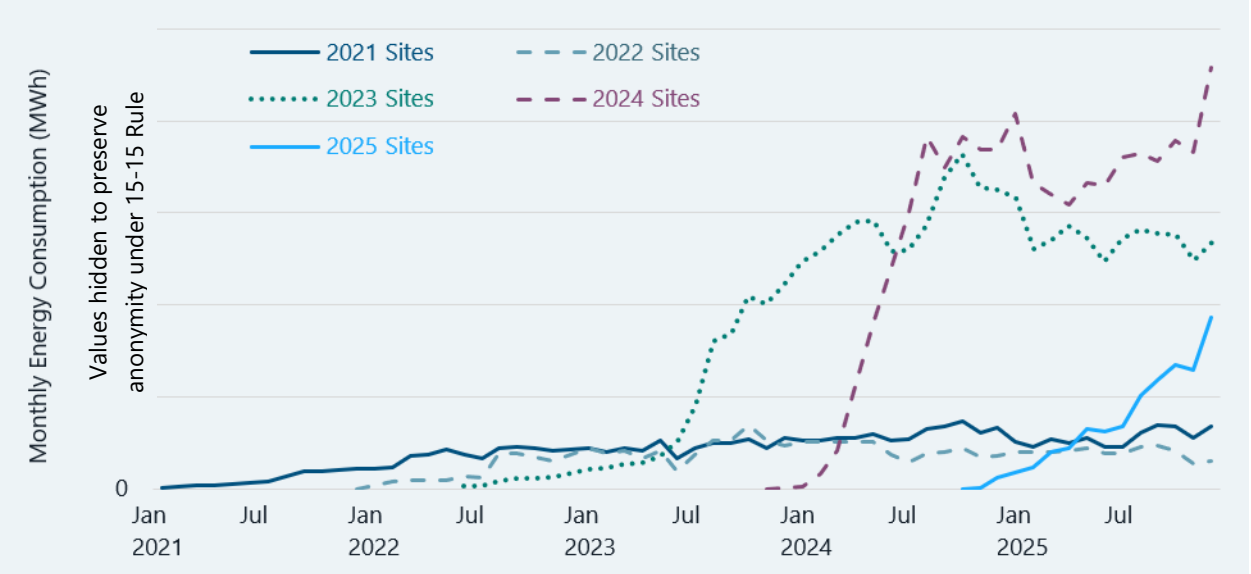
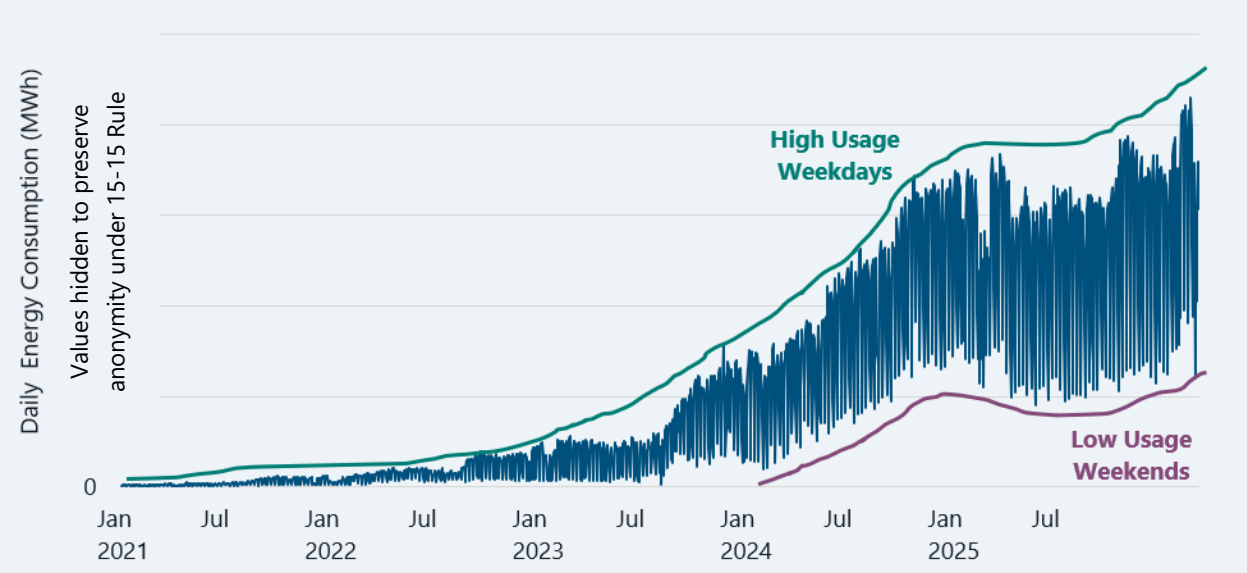


Figure 89 shows daily fluctuations in consumption, with wide variations between weekdays (upper bound) and weekends (lower bound). In the final months of EY2025, weekday daily energy consumption passed 200 MWh, while weekends typically accounted for 25% to 50% of weekday consumption.

Figure 89. SCE Charge Ready Transport Program Daily Energy Consumption for PTD Sites



Maximum demand continues to grow each year. Several days reached a maximum demand of nearly 20 MW, up from a maximum of 14.4 MW in EY2024. Days with low energy consumption (often weekends and holidays) also consistently achieve over 5 MW as shown in Figure 90. Greater consistency in peak demand was observed in EY2025, which is indicative of individual sites having less of an influence on total peak demand as the number of sites (and total demand) increases.

Figure 90. SCE Charge Ready Transport Program Daily Maximum Demand for PTD Sites

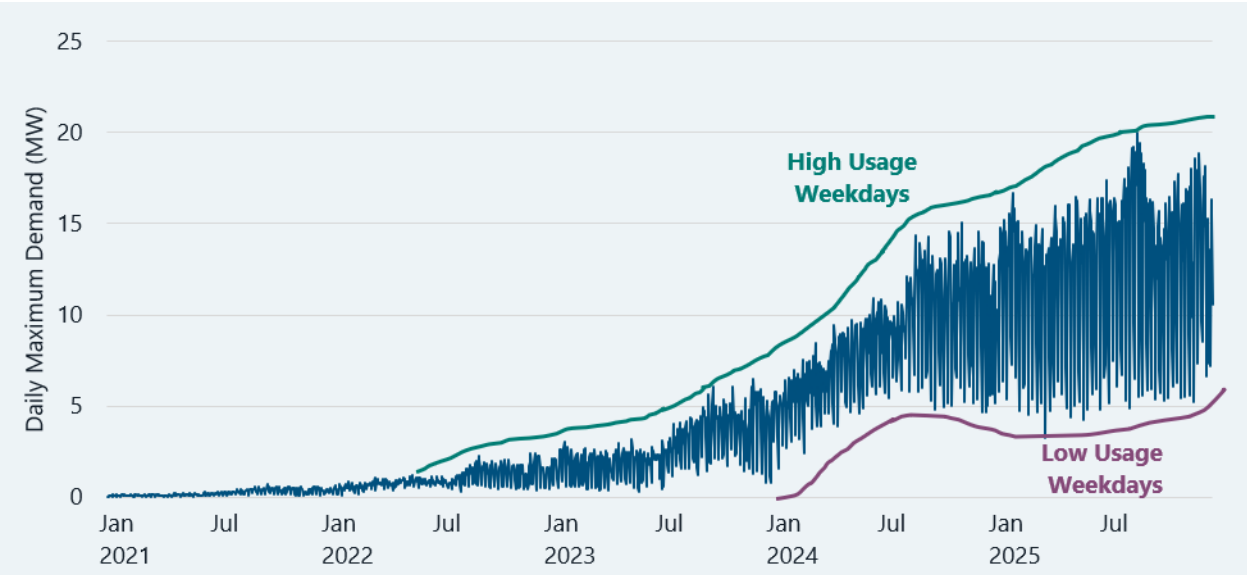
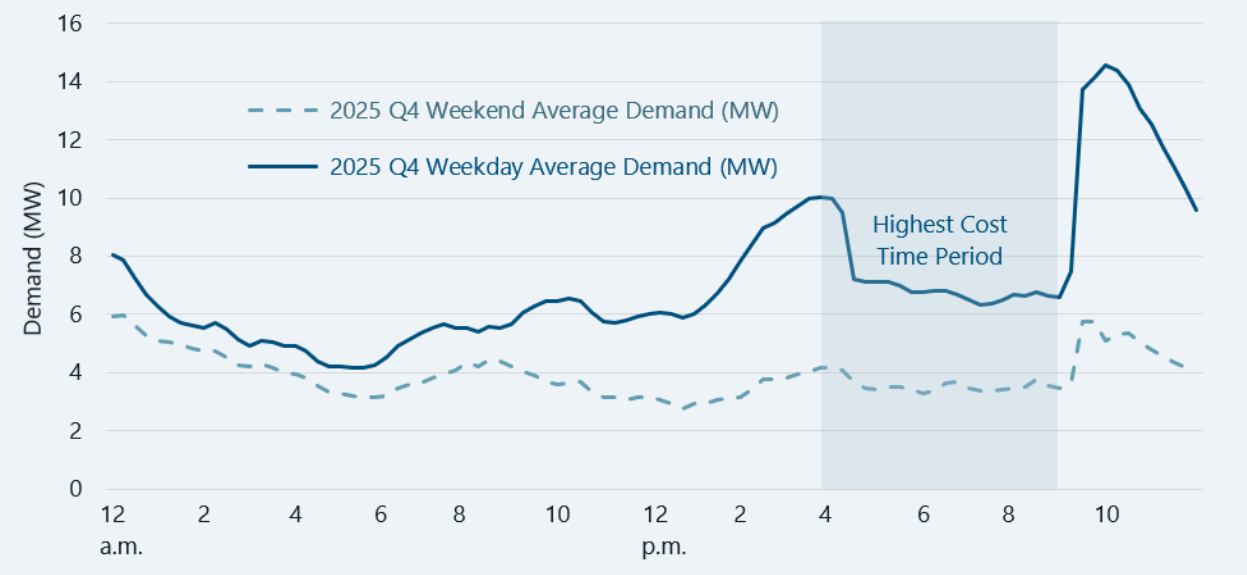


Figure 91 depicts an average weekday and weekend load curve in the fourth quarter of EY2025, which is the period with demand most representative of EY2025 average trends. Notable weekday attributes include an average 2,500 kW drop in demand at 4 p.m. and a steep increase of over 7,000 kW in demand at 9 p.m., indicating the use of load management to avoid high-cost energy. This behavior is also evident on weekends, though to a far lower degree. It is important to note that only approximately 20% of the sites in the SCE portfolio exhibit use of load management, which is similar to sites in other Utility MDHD programs.

Figure 91. SCE Charge Ready Transport Program Average Weekday and Weekend Q4 2025 Load Curves

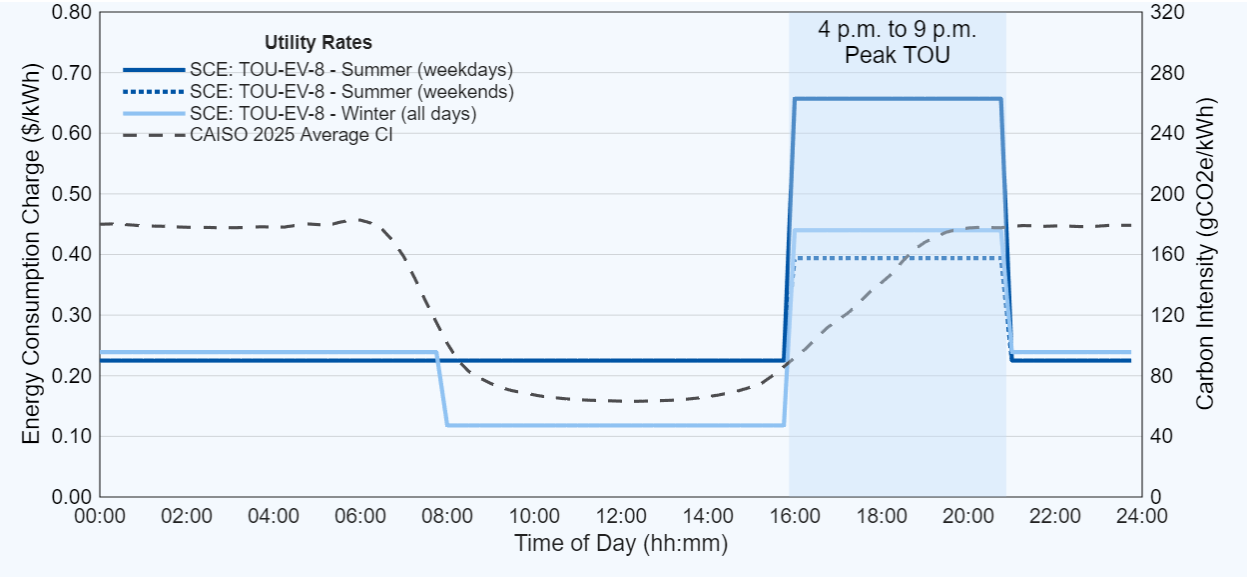


Load Management and Charging Flexibility Analysis

This section describes analyses around load management and charging flexibility. Load-managed sites are those that adopt techniques to avoid charging vehicles during periods of peak energy prices. The analyses consider sites to be load-managed if they exhibited consistent load management regardless of when load management was implemented during the year; otherwise, they are labeled as non-load-managed.

The peak TOU period (daily from 4 p.m. to 9 p.m.) for TOU-EV-8 and TOU EV-9 rate structures (20 kW to 500 kW and >500 kW demand, respectively) in 2025 for SCE's Charge Ready Transport program, provides energy at costs ranging from $0.11/kWh to $0.66/kWh depending on the season and time of day. Figure 92 displays these TOU rate curves for summer and winter weekdays for TOU-EV-8. Winter days (October 1 to May 31) have a Super-Off-Peak period from 8 a.m. to 4 p.m. Lower-cost TOU periods, such as the winter Super-Off-Peak period, often correlate with lower carbon intensity of the grid, as indicated by the dashed line in the figure, which shows the CAISO 2025 average carbon intensity (gCO_2e/kWh). As the actual carbon intensity of the grid varies continuously by time of day and day of year, this reference line indicates the average cost for each time of day across all days in 2025.

Figure 92. SCE Charge Ready Transport Program Hourly TOU Electricity Rates and Average Carbon Intensity in 2025



The Evaluation Team periodically reviews data on a site-by-site basis throughout the year to identify load-managed sites. Visiting sites in person and speaking to fleet managers also provides context around load management intent. SCE is different from the other Utilities in that its EV tariff does not currently include demand-related costs.

Nearly 30 NSPs operate at Charge Ready Transport program sites, with only one-third of these NSPs reporting that their customers consistently use load management. Further, of the 115 operational sites at the end of EY2025, only 21 exhibited strong use of load management, with an additional 15 showing inconsistent use of load management in EY2025.

Load management is evident in several ways:

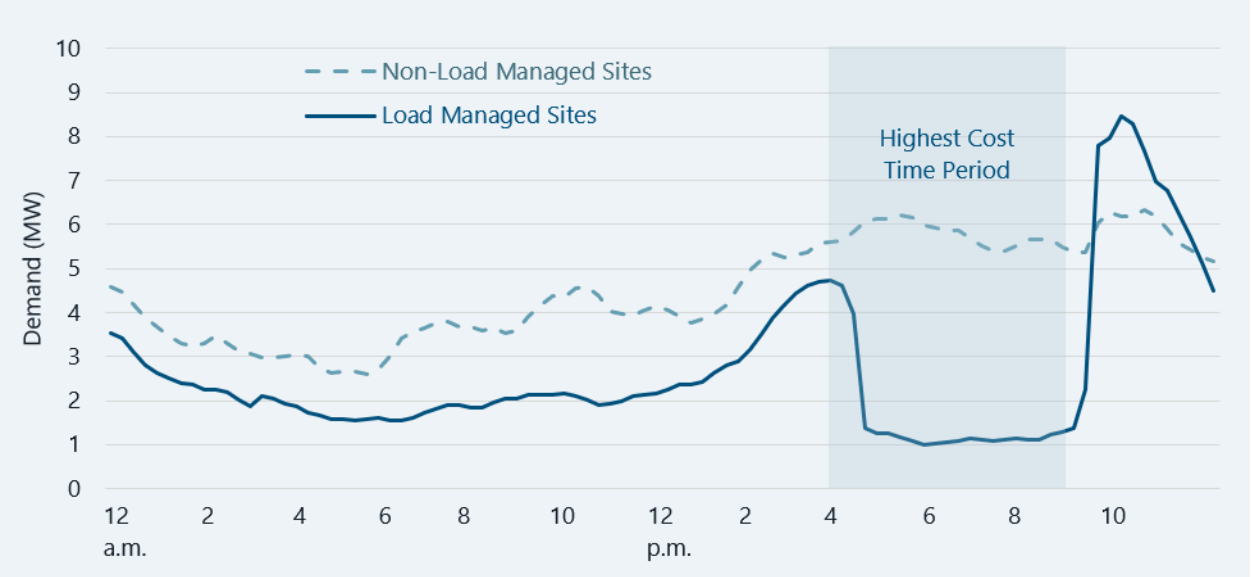
- Load spikes quickly around 9 p.m.
- Charging often drops off steeply at 4 p.m.
- The proportion of total monthly energy consumption between 4 p.m. and 9 p.m. is often below 10%.

The Evaluation Team assessed consumption trends for sites that had implemented load management and those that had not. The group of sites using load management consumed between 15% and 20% of their energy for the month between 4 p.m. and 9 p.m., while sites that did not use load management averaged over 30% during that period. The best individually performing sites in the Charge Ready Transport program are able to achieve total monthly consumption below 10% from 4 p.m. to 9 p.m.

Figure 93 illustrates the differences in electricity demand at different times between load-managed and non-load-managed sites (determined using consumption data). While the curve for the load-managed sites shows demand from 4 p.m. to 9 p.m. some sites showed inconsistent usage in the fourth quarter. In

this example, load begins increasing around noon until 4 p.m. for load-managed sites and drops to less than half, from approximately 6.5 MW to around 3 MW. Individual sites can see even higher load curtailment with almost no load from 4 p.m. to 9 p.m. What would otherwise be an increasing load from 4 p.m. to 9 p.m. is delayed, until a notable load ramp of over 9 MW emerges once prices drop at 9 p.m. Conversely, the curve for the non-load-managed sites shows consistent usage during the afternoon and a small load spike around 9 p.m. from sites that began implementing load management later in the year or used it inconsistently; the Evaluation Team did not consider these sites to have adopted load management for this analysis.

Figure 93. SCE Charge Ready Transport Program Load-Managed and Non-Load-Managed Site Demand, 2025 Q4 (High Consumption and Demand Months), PTD Sites



Charging Flexibility

The Evaluation Team used site charging data to determine the amount of time vehicles are connected to a charging port but not actively consuming energy. This allowed the Team to assess charging flexibility, or the ability for a vehicle to shift charging from periods of high-cost electricity to periods of low-cost electricity without impacting vehicle operations.

Site visits allowed the Evaluation Team to confirm vehicles' make, model, and battery size, all of which affect charging flexibility; to get information about fleets' operational characteristics, and to offer feedback based on the information we gathered. For instance, many school bus charging sessions use less than half of the vehicle's battery capacity. Providing feedback to operators about historical usage trends like charging session duration in relation to battery size and available time to charge may help inform these fleets' charging plans.

Figure 94 shows the relative charging flexibility of various vehicle market sectors**,** using only charging sessions that took place partially or entirely during periods of highest cost electricity and omitting charging sessions that did not overlap with the period between 4 p.m. and 9 p.m.

Figure 94. SCE Charge Ready Transport Program Charging Flexibility for PTD Sites in Sessions Overlapping the Time Period Between 4 p.m. and 9 p.m.

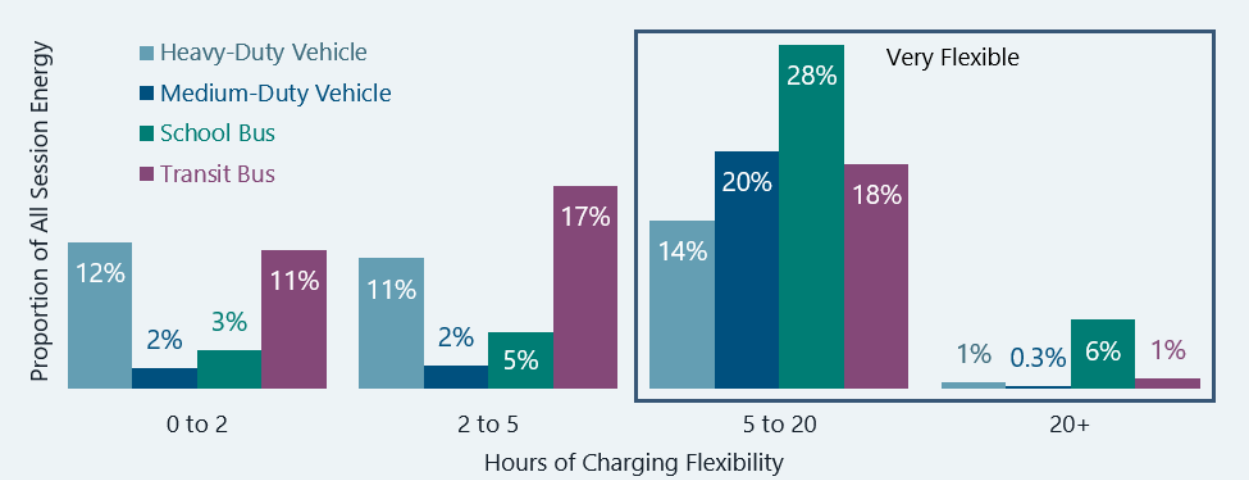


Figure 94 also shows that a high proportion of energy consumption from charging sessions is from vehicles with enough flexibility to entirely avoid the highest-cost time period. Because the period of highest-cost electricity lasts for five hours (4 p.m. to 9 p.m.), a vehicle with a required charging period longer than five hours would need at least five hours of charging flexibility to fully shift consumption from on-peak to off-peak periods. In the example above, 34% of the energy consumed by the school bus sector had over five hours of flexibility (total of sessions with more than five hours of charging flexibility) compared with 19% for transit bus, 15% for heavy-duty vehicle, and 20% for medium-duty vehicle sectors. However, even vehicles with less than five hours of charging flexibility will benefit from adopting load management by shifting a portion of demand to periods of lower-cost electricity. Furthermore, some of these operators use load management, so their vehicles did not charge during the high-cost period; however, these sessions are relevant to the analysis of how much time a vehicle was connected but not drawing power.

Fleets operating a single shift are usually able to benefit the most from load management, while fleets operating multiple daily shifts face the most challenges to leveraging load management, as vehicles charge throughout the day. However, while it is more difficult for sites with multiple shifts to avoid charging during the 4 p.m. to 9 p.m. period, these sites also tend to have consistent use at all times of day. This can avoid typical peak consumption aligned with the end of the typical workday (5 p.m.) and somewhat reduces the proportion of charging from 4 p.m. to 9 p.m., resulting in lower average energy costs on a kilowatt-hour basis.

Costs and Billing

The sum of the monthly billing costs for activated sites in the program to date amounts to $26.7 million. Previous sections have focused on energy trends and charging flexibility, identifying that significant charging is taking place during the peak period of 4 p.m. to 9 p.m. and that much of this load could be shifted to periods of lower demand. The following section examines utility cost and billing trends and identifies how sites may reduce costs based on charging flexibility. The Evaluation Team's review of billing

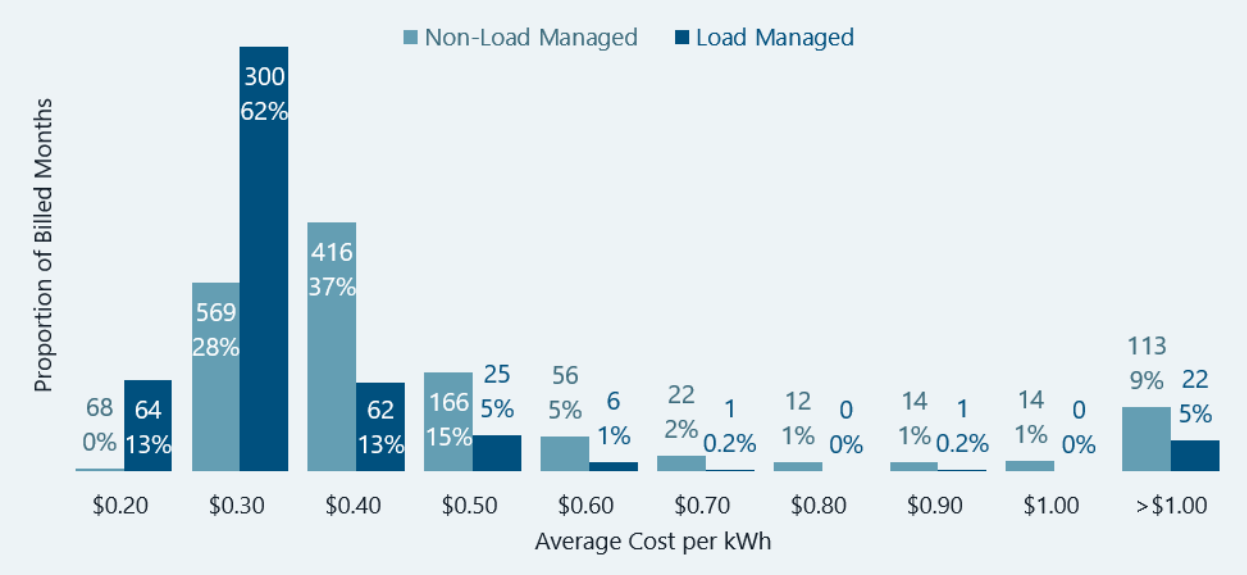
data focuses on the average unit cost of a kilowatt-hour for a given site over a month compared with the TOU-based tariff cost of energy.

NSPs' load management capabilities and fleets' adoption rate of load management impact costs and energy trends. NSPs may provide load management as a base offering or part of a tiered-cost package, depending on the provider. However, interoperability challenges between hardware, software, and vehicles can make load management impractical or difficult to achieve.

Many fleet operators remain unaware of their energy use and charging costs despite receiving utility bills and the data being available from most EVSPs. Often a site host's finance office will receive utility bills but will not share information with fleet operators that would enable them to compare energy costs for the fuel types in their fleets. The Evaluation Team uses data on energy consumption trends as discussion points during site visits if operations have started. Many fleet operators have said they had not seen these data trends prior to the evaluation site visits.

Figure 95 shows the distribution of the average monthly electricity cost per kilowatt-hour for PTD sites for which at least six months of billing data was available in 2025. SCE base rates range between $0.11/kWh and $0.66/kWh, before adding services fees and taxes. The best results appear to show monthly billing between $0.16/kWh and $0.40/kWh through use of load management intervening on TOU (avoiding 4 p.m. to 9 p.m.), combined with a high volume of energy consumption. For PTD sites, 55% of EY2025 billing months were over $0.30/kWh, with several sites averaging over $0.60/kWh.

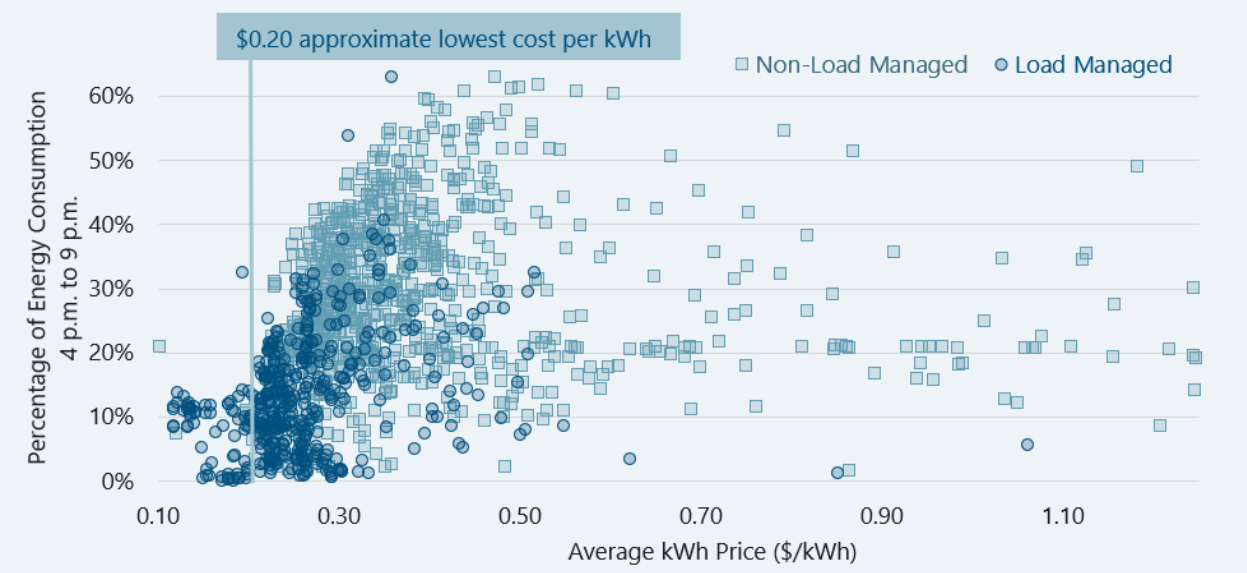
Figure 95. SCE Charge Ready Transport Program
Summary of Average Monthly Electricity Cost



1,451 2025 billing months, which include some overlapping billing months in January and December.

Figure 96 shows all 2025 billing months with color coding to indicate whether or not the fleet was observed to have used load management in 2025. The data points show that load-managed billing months trend to lower average energy costs, a direct benefit to the fleet. This also shows that these fleets consume lower proportion of energy between 4 p.m. and 9 p.m., which benefits ratepayers and utilities.

Figure 96. SCE Charge Ready Transport Program 2025 All Billing Months Average Electricity Costs per Kilowatt-Hour for Load-Managed and Non-Load-Managed Sites



To better highlight energy and billing trends, Figure 97 through Figure 100 show the energy and billing trends across sites, grouped by high, medium and low billing months relative to total megawatt-hours consumed. Each dot represents a billing month.

Figure 97 illustrates the positive relationship between the percentage of on-peak energy consumption and the average monthly customer bills for sites using more than 20 MWh and highlights the potential financial opportunity to use load management to reduce costs. The EY2025 data show slightly lower consumption between 4 p.m. and 9 p.m. and lower average costs than in prior evaluation years. The lowest costs the Team observed were around $0.12/kWh for high-usage months. Medium- and low-usage months had a floor of around $0.20/kWh.

Figure 97. SCE Charge Ready Transport Program Percentage of Monthly Energy Consumed from 4 p.m. to 9 p.m. vs. Average Energy Price for High-Consumption Billing Months (>20 MWh) for PTD Sites

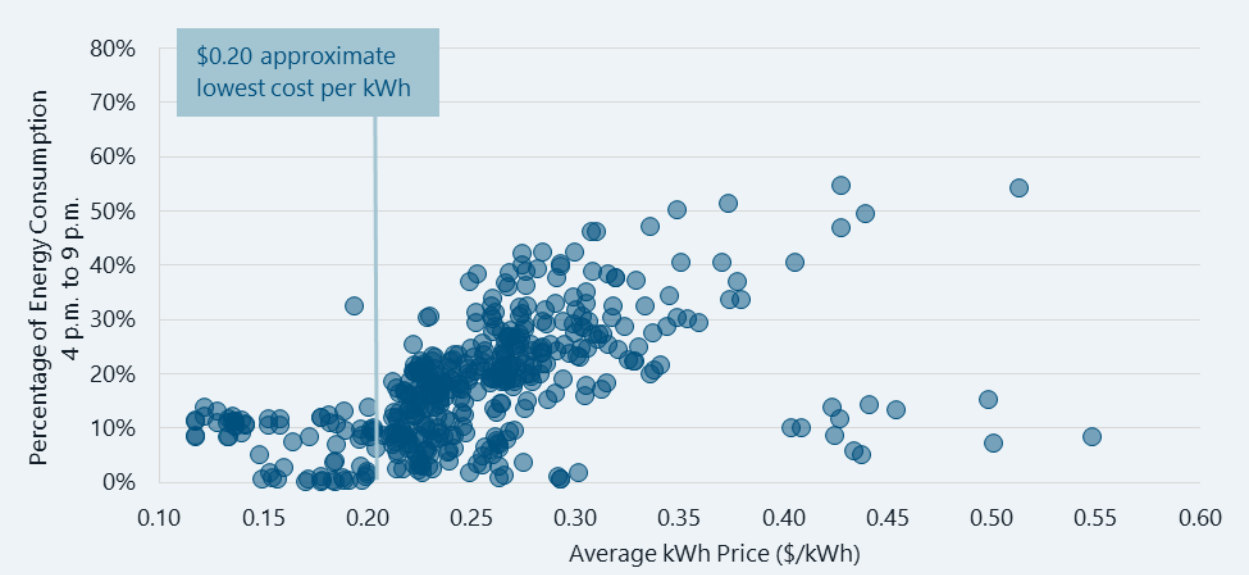
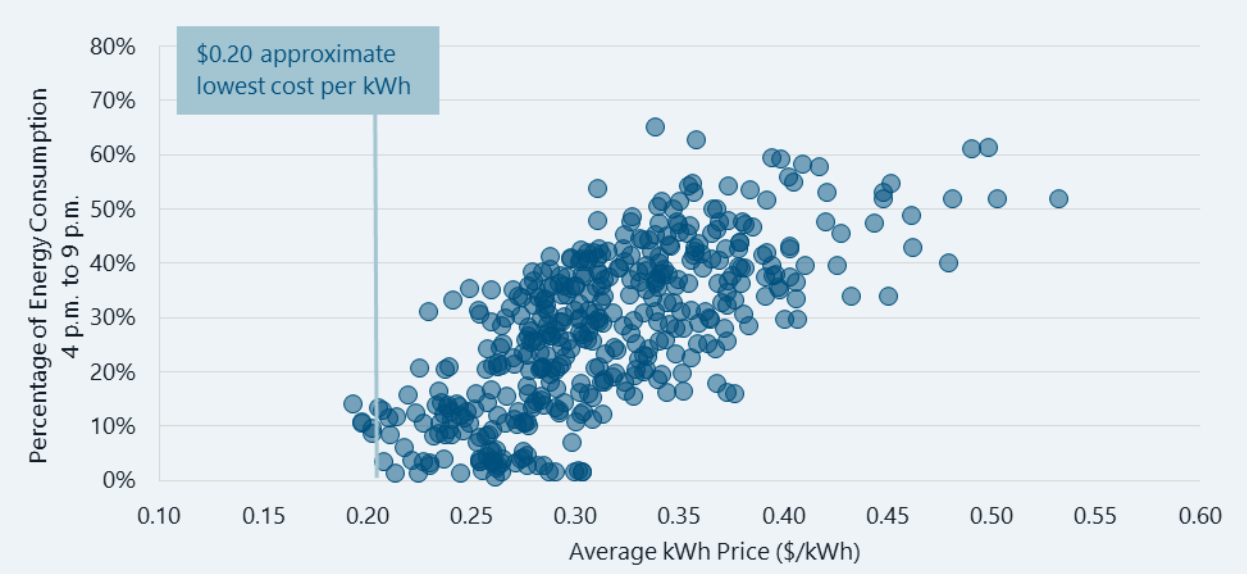


Figure 98 shows billing for sites that consume between 5 MWh and 20 MWh. These months also show a strong positive correlation between energy consumption from 4 p.m. to 9 p.m. and average unit pricing. This should provide further encouragement for fleets to focus on improving their load-management efforts. Many of the sites that have adopted load management show an electricity cost of $0.20/kWh to $0.30/kWh. Therefore, cost savings of 30% for users historically averaging $0.40/kWh or more per kilowatt-hour are likely achievable through load management. Notably, more sites with consumption of 5 MWh to 20 MWh per month have average electricity prices that are greater than $0.40/kWh than sites with consumption less than 20 MWh, highlighting the ability for smaller fleets to reduce costs.

Figure 98. SCE Charge Ready Transport Program Percentage of Monthly Energy Consumed from 4 p.m. to 9 p.m. vs. Average Energy Price for Medium-Consumption Billing Months (5 MWh to 20 MWh) for PTD Sites



Fleets that used less than 5 MWh per month show a greater correlation between average unit pricing and overall monthly consumption. Figure 99 illustrates that sites with the lowest monthly energy consumption often have the highest electricity costs per kilowatt-hour. This can be attributed to fixed fees, which are spread across the total kilowatt-hours consumed and therefore have a greater impact on sites with lower total consumption.

Figure 99. SCE Charge Ready Transport Program Total Monthly Energy Consumed vs. Average Energy Price for Low-Consumption Billing Months (<5 MWh) for PTD Sites

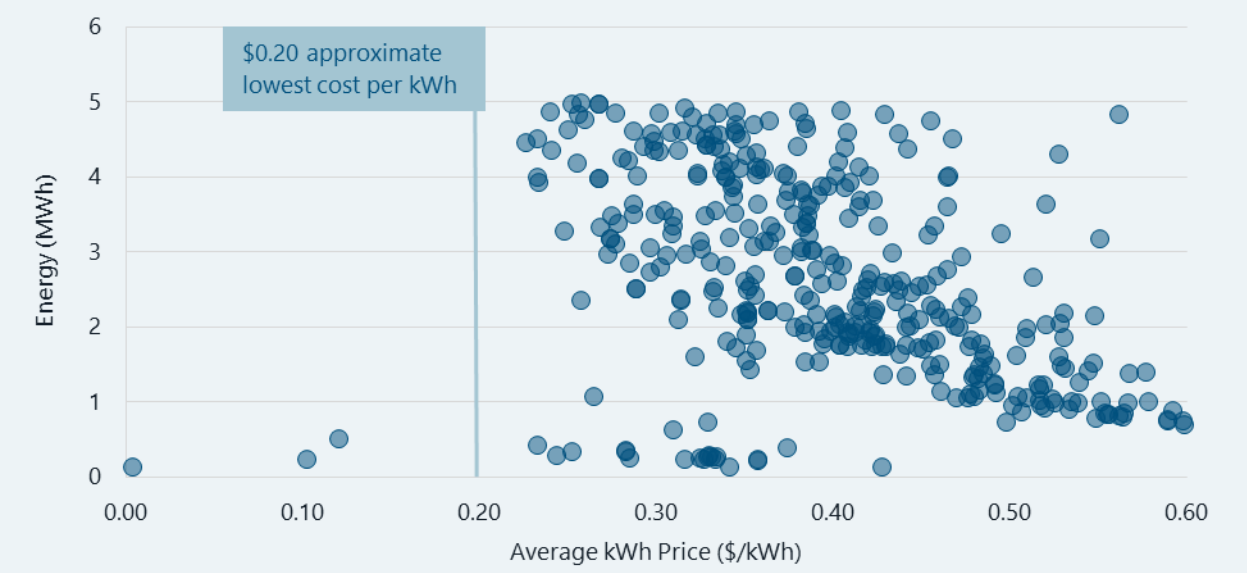
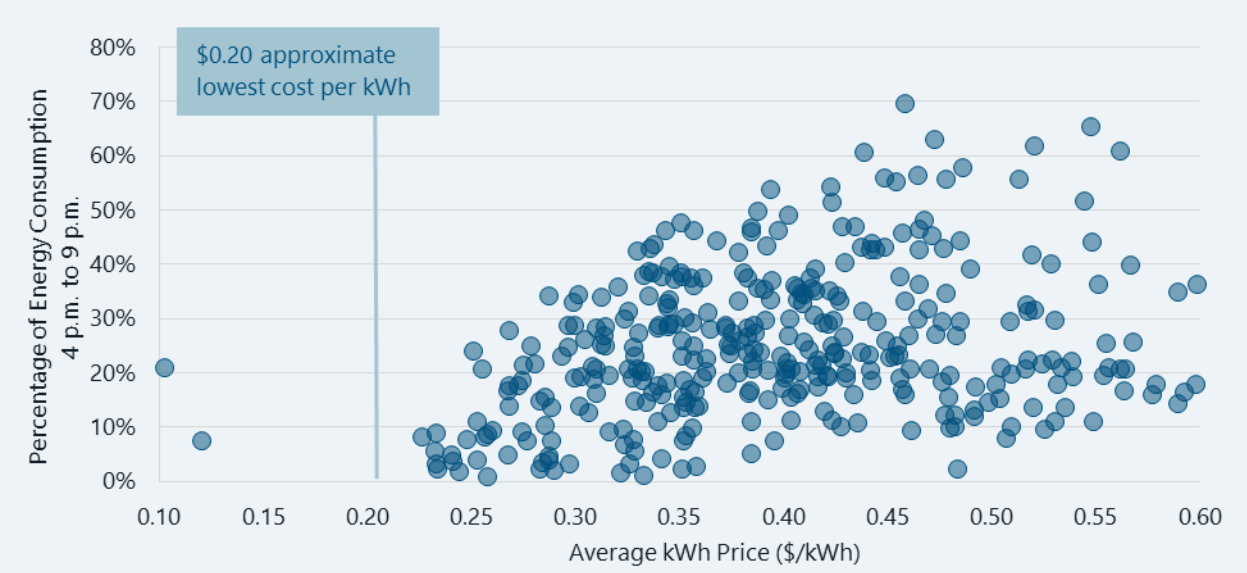


Figure 100 also shows a correlation between the proportion of energy consumption from 4 p.m. to 9 p.m. and the average energy price for lower energy consumers, similar to what occurs with higher-energy users, highlighting the opportunity for low energy users to reduce costs by using load management.

Figure 100. SCE Charge Ready Transport Program Percentage of Monthly Energy Consumed from 4 p.m. to 9 p.m. vs. Average Energy Price for Low Consumption Billing Months (<5 MWh) for PTD Sites



Electricity Cost and Emissions Optimization Analysis

This section builds upon the grid impact findings above to provide an analysis of hypothetical customer bills and emissions under an optimal load management scenario, assuming perfect load management across all sites. While real-world constraints, such as from technology, operations, and education, currently prevent ideal load management, the findings shed light on the long-term potential of load management. To quantify the potential benefits of using load management, the Evaluation Team analyzed observed outcomes of sites with and without existing load management practices and conducted a load-shifting optimization exercise to estimate potential cost savings and emissions reductions. This optimization analysis utilizes NSP data, where available, to assess charging flexibility for each site. For sites without sufficient NSP data reported, the analysis uses AMI data and a charging session availability template to assess charging flexibility. The analysis derives the template for each market sector based on the charging behavior of sites in that sector with NSP charging session data.

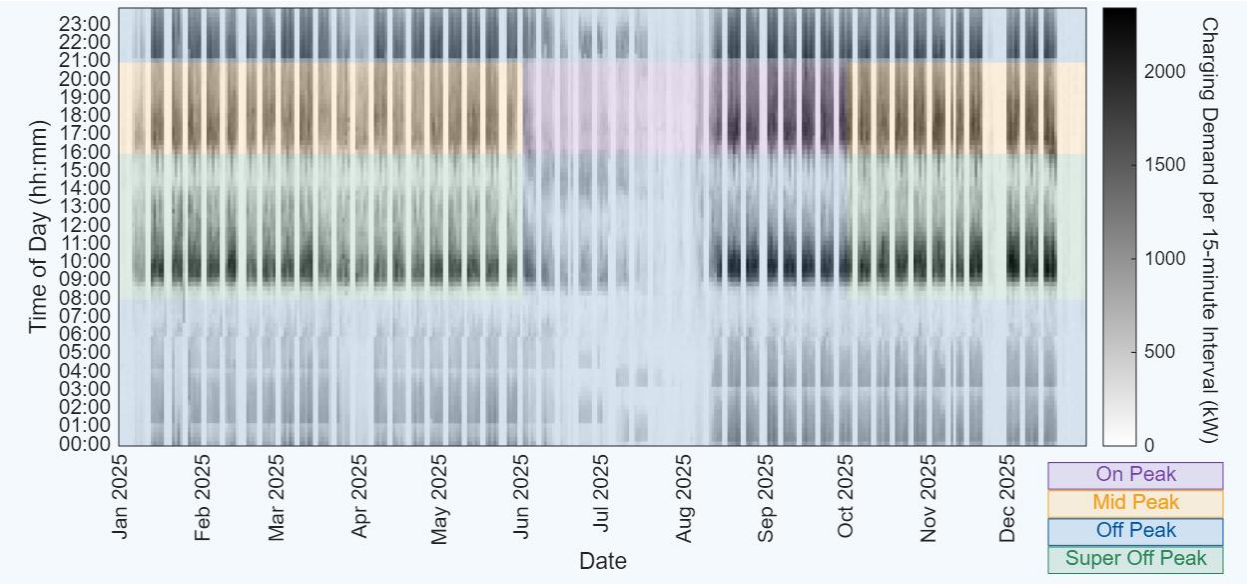
Load Management Outcomes Observed in EY2025

Of the 115 operational PTD sites, the Evaluation Team assessed 97 sites with AMI and NSP data that met the requirements for analysis. Of these 97 sites, 36 were school bus sites and 61 were from other market sectors, including transit bus, medium-duty vehicle, heavy-duty vehicle, port cargo truck, and forklift.

Figure 101 and Figure 102 depict the BAU historical energy consumption of school bus fleets and non-school bus fleets, respectively, in aggregate during EY2025. BAU represents the current charging behavior of the 97 sites used for this analysis. The areas in the figures with darker shading correspond to times of

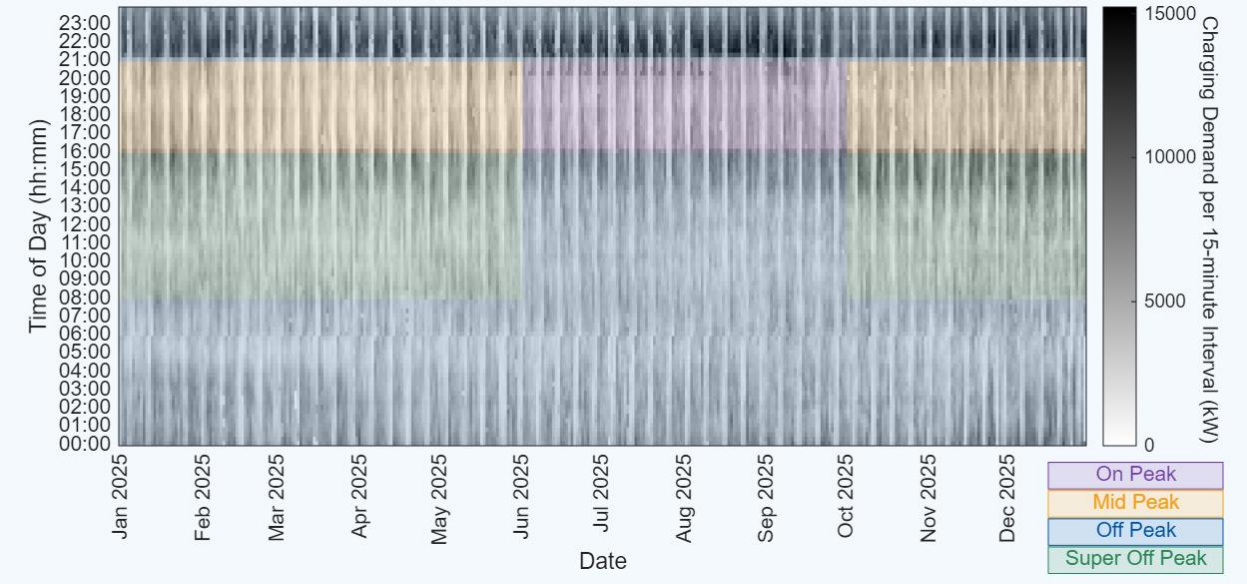
day (y-axis) and days throughout the year (x-axis) with higher collective charging demand, as measured by the scale on the right of the plot. Areas with no shading indicate no energy demand. The colored regions of the plot correspond to the Utility's TOU periods (on-peak, mid-peak, off-peak, and super-off-peak). School bus fleets show a consistent trend of charging twice per day: once beginning around 9 a.m. after the morning routes to pick up students, and again around 4 p.m. to 5 p.m. after buses complete afternoon runs. The second charging session directly coincides with higher TOU rates. Some sites using load management are clearly delaying charging until 9 p.m. to avoid peak TOU energy costs. The figure also shows lower demand during winter break, spring break, and summer vacation periods when school bus operation is minimal. In 2025, it appears that many school bus sites deployed more electric buses and/or increased the charging levels after returning from the summer break, which contributed to the continued program growth in 2025.

Figure 101. SCE Charge Ready Transport Program Heatmap of the Collective BAU Charging Demand for All SCE School Bus Fleets in EY2025



Dark shading intensity indicates average charging demand (kW) per 15-minute interval. Colored regions indicate TOU periods.

Figure 102. SCE Charge Ready Transport Program Heatmap of the Collective BAU Charging Demand for All SCE Non-School Bus Fleets in 2025

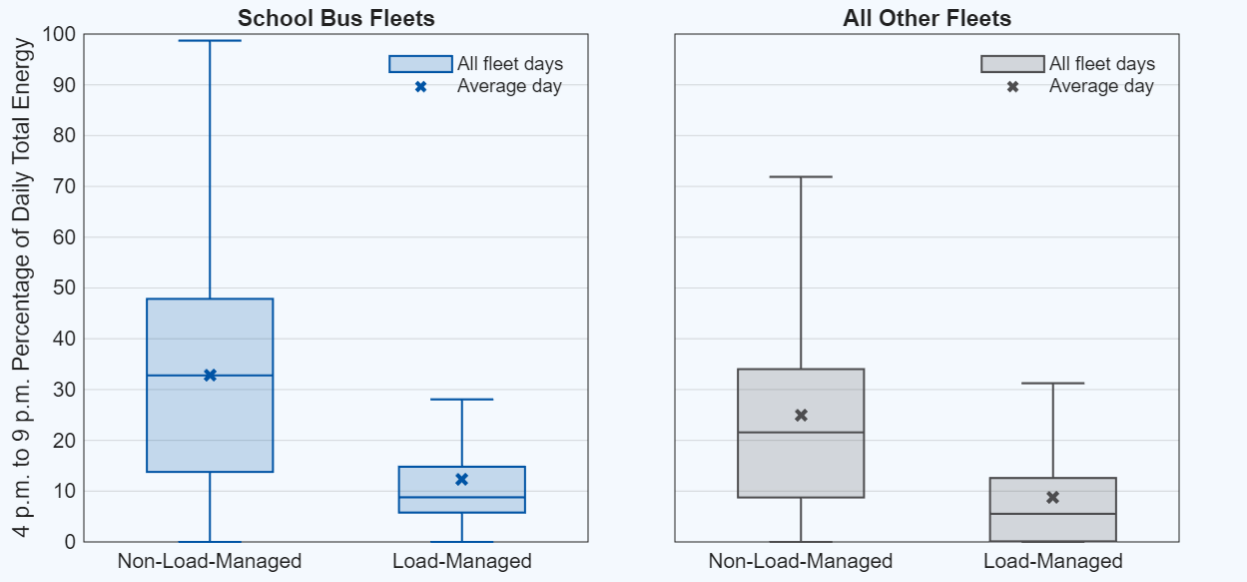


Dark shading intensity indicates average charging demand (kW) per 15-minute interval. Colored regions indicate TOU periods.

The Evaluation Team compared NSP charging sessions that utilized load management strategies to non-load-managed sessions for the school bus and non-school bus fleets to evaluate the effectiveness of the existing load management at minimizing energy during the 4 p.m. to 9 p.m. peak TOU period.

The box plots in Figure 103 compare the distributions of daily on-peak (4 p.m. to 9 p.m.) energy consumption, as a percentage of daily total energy, between load-managed and non-load-managed days. On average, non-load-managed school buses show approximately 33% of daily consumption occurring between 4 p.m. and 9 p.m. For the average load-managed day, the percentage drops significantly to 13% of overall consumption. For other market sectors (shown on the right), the average non-load-managed day shows 35% of consumption during the peak TOU period, compared with just under 10% for load-managed days.

Figure 103. SCE Charge Ready Transport Program Distribution of the Fraction of Daily EV Charging Load Occurring in the Peak TOU Period



The box and whisker plot represents the distribution of daily total energy consumed from 4 p.m. to 9 p.m. across one operating day by group, with the average value for all operating days per group indicated by an X.

This analysis strongly suggests that the few fleets with existing load management programs effectively reduce the fraction of energy consumed between 4 p.m. and 9 p.m. and thereby reduce their energy consumption costs.

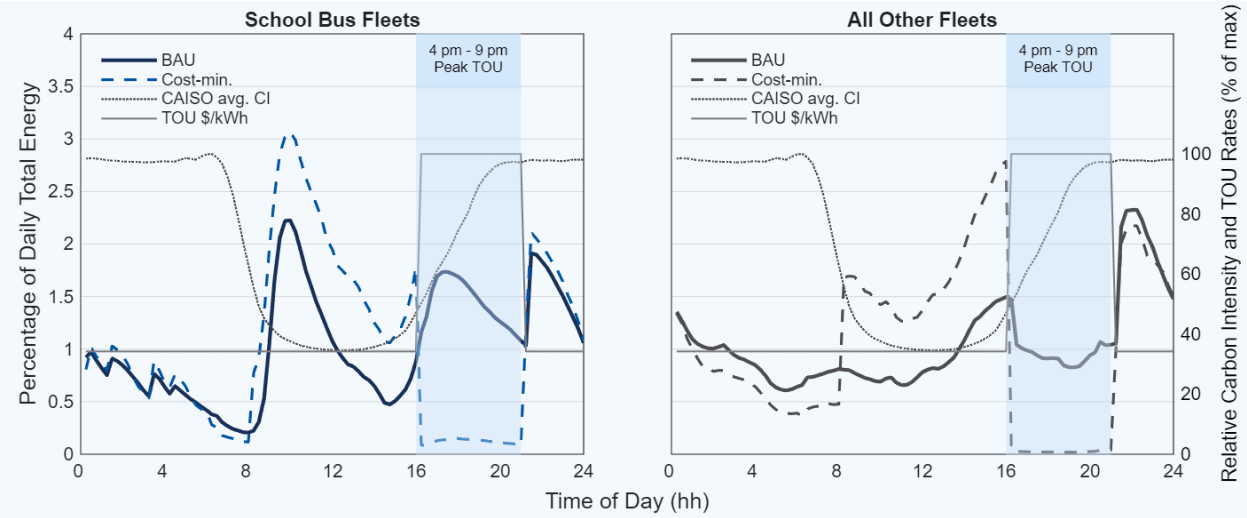
Potential Benefits of Optimal Load Management

The Evaluation Team analyzed charging session data to estimate the value of optimal load management, considering each site's observed operating patterns and potential ability to shift vehicle charging loads. This analysis included 36 school bus sites and 61 sites in other market sectors that had sufficient AMI and NSP data reported for EY2025 to complete the optimization.

The Evaluation Team developed and executed an optimization routine that reviews each site's daily charging behavior and shifts energy consumption from the peak time period (4 p.m. to 9 p.m.) to the lowest-cost periods of the day whenever there was both unused charging capacity and vehicle charging availability during those periods. The Evaluation Team used NSP charging session data to ascertain how many vehicles were plugged in and how many kilowatt-hours of energy could have been shifted during each time period. For hours in the same TOU rate period, the Team used carbon intensity of the electric grid (evaluated from CAISO 2025 GHG emissions factors) and BAU charging load as tiebreakers to determine vehicle charging priorities. Though the optimization algorithm is capable of incorporating monthly demand charges, SCE TOU-EV-8 and TOU-EV-9 tariffs do not currently use these. After completing the load-shifting to minimize costs, the Evaluation Team calculated the costs and GHG emissions for the load-shifted case and compared the results to the BAU case to determine the potential reductions in cost and GHGs for each site.

Figure 104 illustrates how optimally shifted loads differ from BAU loads, averaged across EY2025. For both school bus and other market sector sites, the average day's load can be almost completely shifted from the high cost 4 p.m. to 9 p.m. window and to midday charging (8 a.m. to 4 p.m.), overnight charging (9 p.m. to 8 a.m.), or both. These time periods offer the lowest energy consumption costs, and the midday charging period (which has off-peak rates during summer months and super-off-peak rates during winter months) also corresponds to the lowest average carbon intensity of grid electricity.

Figure 104. SCE Charge Ready Transport Program Fraction of Daily EV Charging Load Occurring at Each 15-Minute Interval for the Average Day in this Analysis, BAU Compared with Cost-Minimization



Line color indicates site market sector and dashed versus solid lines indicate whether the load is BAU or shifted.

Figure 105 shows the cost reduction that sites could have achieved in 2025 in total dollars for each of the 97 sites the Team analyzed. Each bar represents the hypothetical savings by site if the site had used its charging flexibility to minimize electricity costs. The sites are segmented into load-managed and non-load-managed sites. The top graph shows the total dollar value of savings, and the bottom graph shows the percentage savings.

The following key methodological notes provide context for this analysis:

- The analysis considers the volumetric (cost per kilowatt-hour) component of each site's electricity costs as well as any demand charges that may apply under the Utility's rate structure. The cost-minimization approach developed in this analysis ensures that the monthly total cost (energy consumption plus demand charges) will be minimized. This allows for an increase in monthly peak demand as long as any applicable charges for increased demand are more than offset by TOU cost savings resulting from load-shifting to less expensive TOU periods. In most cases, monthly peak demand either stayed the same, having no impact on costs, or decreased, resulting in additional cost savings.
- These results reflect only the portion of the year in which each fleet operated vehicle chargers and provided charging data; annualized projections of these cost reductions could be substantially

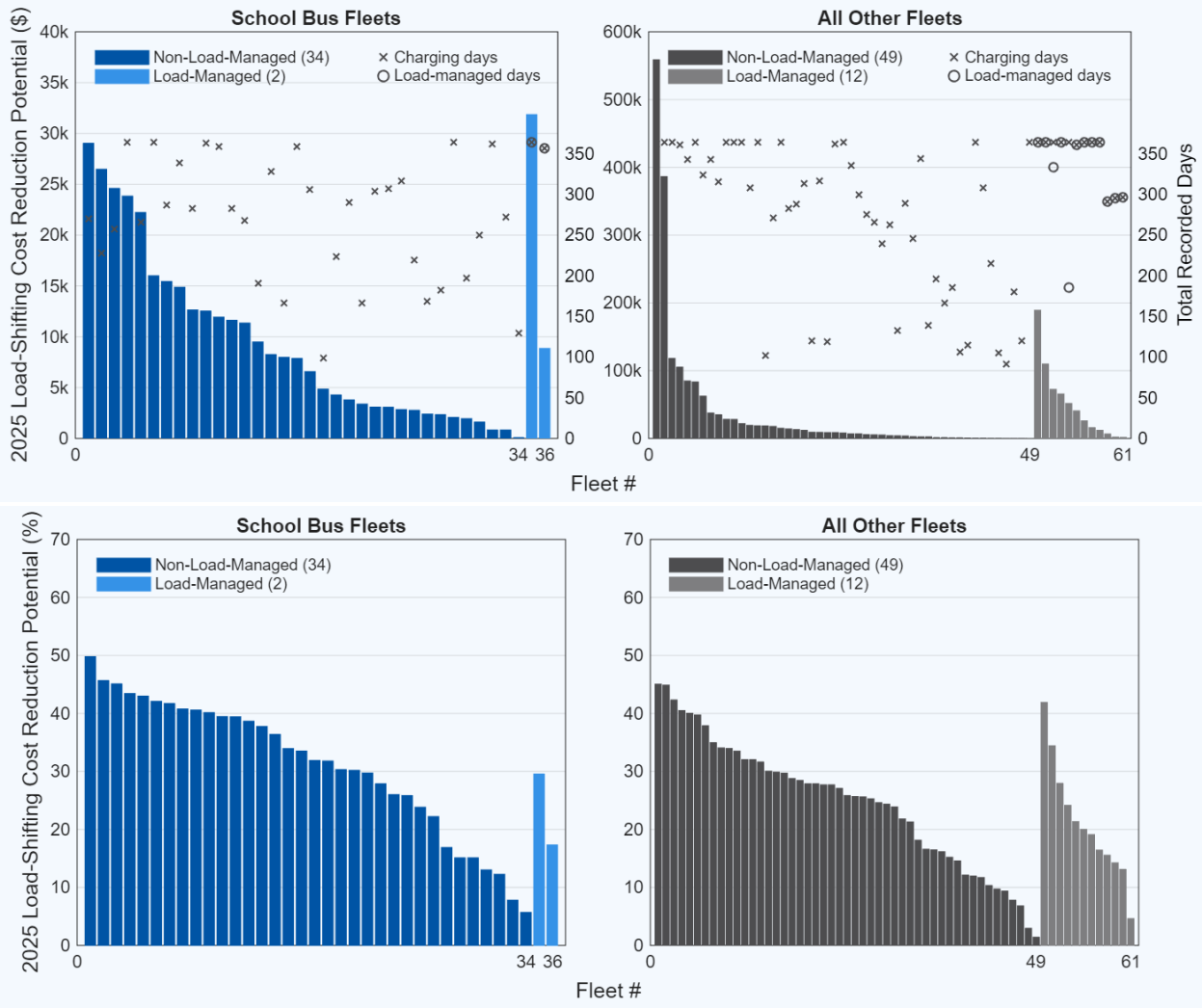
higher for fleets that have less than a full year of charging data included in this analysis or that have not yet reached mature operations.

- These results reflect only the portion of each site's vehicle fleet that it electrified in EY2025. A fully electrified vehicle fleet would see higher cost reduction potential from load management.
- This analysis considers the cost-saving potential of load management but does not consider the potential of load management to generate revenue via LCFS Smart Charging credits.
- This analysis examined actual charging behavior at each site (using actual recorded plug-in and unplug times) to determine charging opportunities and does not account for other operational or scheduling improvements for charging electrified fleets, which could enable more-effective load management, resulting in higher potential cost reduction.

Figure 105 provides several insights. The figure shows that even load-managed sites have the potential to save energy by better utilizing their charging flexibility. For example, as shown on the top graph, sites that are already using load management have cost reduction potential of over $30,000 in the school bus market sector and up to $188,000 for the largest sites in other market sectors. In general, sites that are implementing load management have less opportunity to realize additional savings than sites that have not implemented load management to date. However, many of these sites can capture additional savings by improving consistency of load management operations and better coordinating load management scheduling if their EVSP is capable and their operations allow.

Non-load-managed sites have cost reduction potential of up to $29,000 for school bus sites and $563,000 for other market sectors. Sites that have the greatest potential savings are extremely large sites with high energy consumption and therefore higher overall costs. For example, as shown in the bottom graph, the load-managed fleet with the $563,000 cost reduction potential has an estimated 38% cost reduction potential, which is similar to many other fleets regardless of market sector.

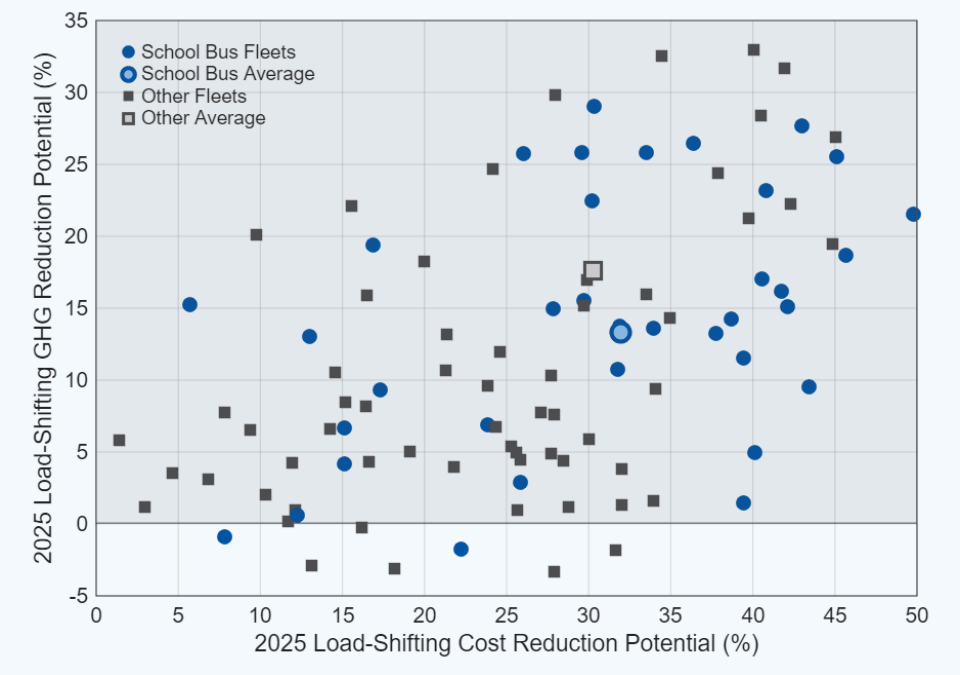
Figure 105. SCE Charge Ready Transport Program Total Annual Cost Reduction Potential of Each Site with Use of Optimal Load Management



Each bar represents one site. Bar colors indicate the site's market sector, and bar shades show its use of load management.

Because lower-cost TOU periods often correspond to periods with lower carbon intensity for grid electricity, optimizing load management for energy cost savings can have a secondary effect of reducing the resulting carbon emissions from vehicle charging. Figure 106 shows estimated cost reductions and corresponding GHG emissions reductions for each site resulting from a cost-minimizing load-management strategy (considering carbon intensity only as a tiebreaking factor when there is sufficient charging flexibility). The majority of sites (school bus and other market sectors) could achieve a significant reduction in GHG emissions, approximately 15%, on average, and up to more than 33% in one case, simply by minimizing charging costs.

Figure 106. SCE Charge Ready Transport Program Potential Percentage Cost Reduction and Attributed GHG Emissions Reduction of Optimal Load Management, Cost-Minimization



In addition to the cost-minimization load-shifting analysis, the Evaluation Team evaluated the maximum achievable reduction in GHG emissions with load-shifting. To do this, the Team reran the load-shifting optimization routine on the same data set with the objective of minimizing GHG emissions at each site. This approach maximizes the amount of charging that can take place during the middle of the day when the carbon intensity of grid electricity is the lowest, given that additional charging capacity and vehicle charging availability exists at each site. Figure 107 shows how the average charging load profile for the GHG-minimization approach compares with the cost-minimization and BAU average load profiles. Figure 108 displays the resulting combination of cost-reduction potential and emissions-reduction potential for each site when load shifting is employed to minimize GHG emissions.

Figure 107. SCE Charge Ready Transport Program Fraction of Daily EV Charging Load Occurring at Each 15-Minute Interval for the Average Day in this Analysis, BAU Compared with Cost-Minimization and GHG-Minimization

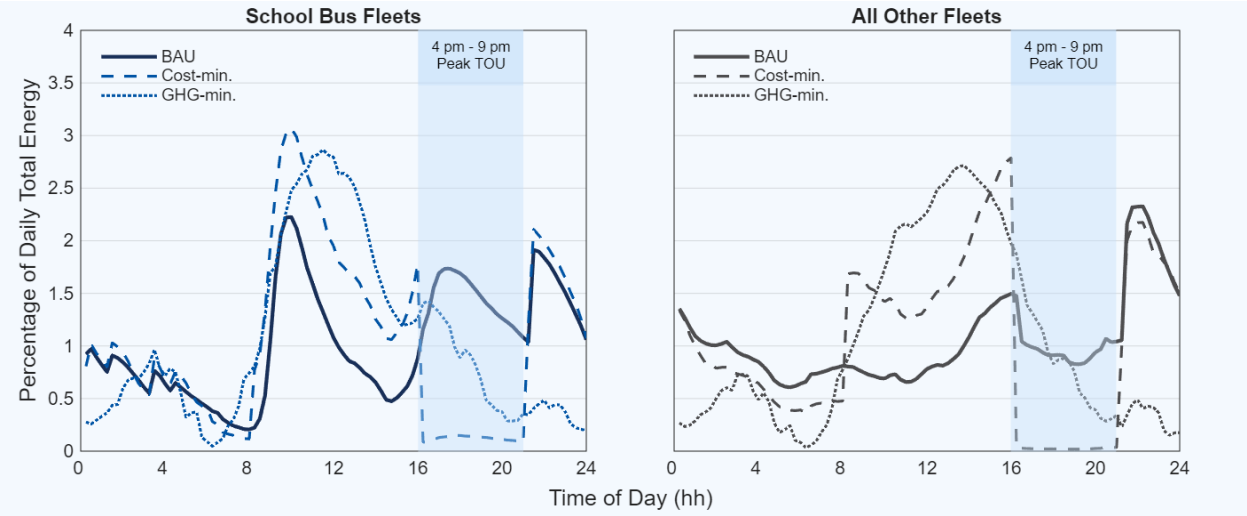


Figure 108. SCE Charge Ready Transport Program Potential Percentage Cost Reduction and Attributed GHG Emissions Reduction of Optimal Load Management, GHG-Minimization

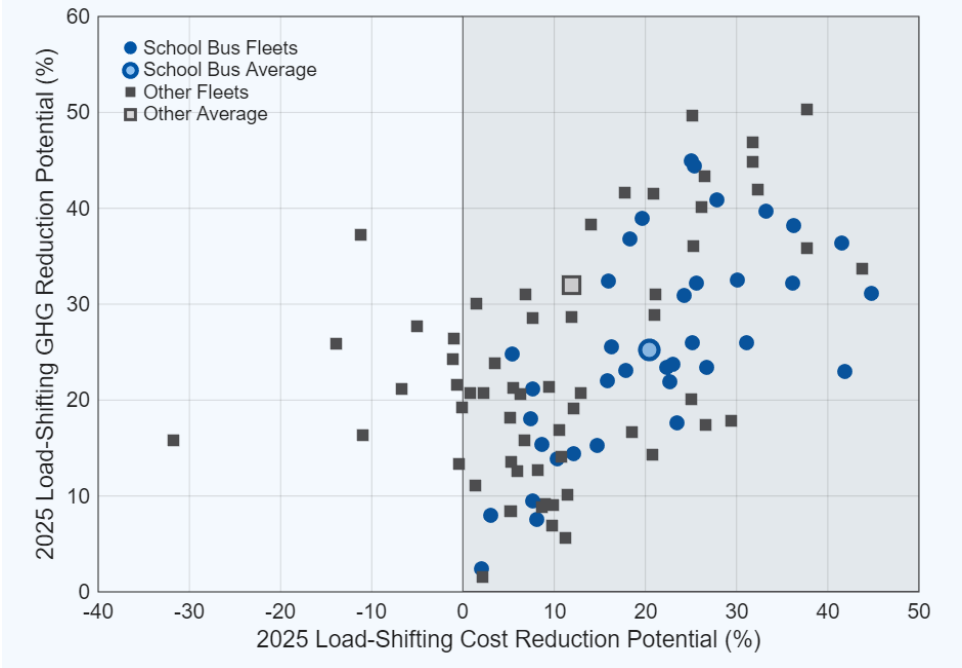


Table 36 aggregates these results across all sites included in the analysis. Overall, optimizing load shifting to minimize charging costs could reduce school bus sites' collective energy consumption costs by 31% and attributed electricity grid GHG emissions by 10%; for other market sectors, it could reduce energy consumption costs by 29% and attributed electricity grid GHG emissions by 14%. Load shifting to minimize GHG emissions across all sites could achieve GHG emissions reductions that are two to three

times higher than the cost-minimization approach, but these reductions would come with lower cost savings. One question that arises is how to best use the lowest-emission energy. One potential answer to this question is to adopt processes from demand response programs by instructing customers to add load during times of substantial low-emission energy and providing financial incentives, instead of demand response financial penalties. The CEC has supported piloting such solutions through its Responsive, Easy Charging Products with Dynamic Signals (REDWDS) program.

Table 36. SCE Charge Ready Transport Program Summary of Potential Cost and Attributed GHG Emissions Reductions, Aggregated across All Included Fleets

	School Bus Fleets	All Other Fleets	All Fleets Combined
2025 Total Number of Fleets	**36**	**61**	**97**
2025 Total Operating Days	**9,854**	**17,311**	**27,165**
Cost-Minimization Load-Shifting			
Cost Reduction Potential ($)	353,646	2,370,907	2,724,553
GHG Reduction Potential (kg CO_2e)	70,397	845,566	915,962
Cost Reduction Potential (%)	32.0%	30.3%	30.5%
GHG Reduction Potential (%)	13.4%	17.6%	17.2%
GHG-Minimization Load-Shifting			
Cost Reduction Potential ($)	225,966	929,884	1,155,850
GHG Reduction Potential (kg CO_2e)	132,833	1,537,264	1,670,098
Cost Reduction Potential (%)	20.4%	11.9%	12.9%
GHG Reduction Potential (%)	25.2%	32.0%	31.3%

Highlights

- Maximum demand reached 20 MW of the 131 MW of installed capacity.
- Although nearly 30% of sites began vehicle charging within 30 days of power availability, 35% took over 120 days.
- Only one-third of NSPs have customers consistently using load management. 21 of 115 operational sites at the end of EY2025 exhibited strong use of load management. An additional 15 showed inconsistent use of load management in EY2025.
- Sites in aggregate activated in EY2025 show growth throughout the year while sites activated in earlier years showed tapered off growth in consumption, indicating operations becoming mature.
- Charging data indicates that there is significant opportunity for most fleets to shift their charging energy use to lower-cost time periods. Potential savings are as high as 45%.
- On average, sites can reduce GHG emissions by 14% by avoiding consumption from 4 p.m. to 9 p.m. while maintaining or improving historical costs.

Petroleum Displacement

The Evaluation Team estimated the petroleum displacement attributable to vehicle electrification enabled by SCE's Charge Ready Transport program. The Team used diesel gallon equivalent (DGE) for reporting purposes. As the transit bus market sector primarily uses CNG fuel, the Team converted transit bus natural gas consumption to DGE units based on the CNG fuel's energy content.

Table 37 presents petroleum displacement impacts for the SCE Charge Ready Transport program through 2025, including estimated actual impacts for 2025, actual impacts for PTD sites, and a 10-year forecast for PTD sites. The results include the seven market sectors represented in the program, with the majority of vehicles in the heavy-duty vehicle sector followed by the medium-duty vehicle sector. The usage in the program to date is over 68 million electric miles, estimated based on electricity consumption of just over 103,852.67 MWh. This translates to displacement of over 8 million DGE.

Table 37. SCE Charge Ready Transport Program Petroleum Displacement Summary

Market Sector	Usage (n=115)				Petroleum Displacement (DGE)		
	2025 Actual [a] kWh	PTD Actual [b] kWh	2025 Actual Use	PTD Actual Use	2025 Actual	PTD Actual	10-Year Projection
Forklift			820 hours	1,783 hours	853	1,854	5,750
Heavy-Duty Vehicle			10,930,684 miles	20,325,415 miles	1,658,842	3,011,807	14,445,981
Medium-Duty Vehicle			9,712,785 miles	24,081,945 miles	496,566	1,312,436	3,561,498
Port Cargo Truck			6,252,265 miles	12,481,430 miles	920,317	1,847,665	7,076,293
School Bus			3,176,781 miles	8,456,352 miles	348,348	928,819	2,574,280
Transit Bus			1,361,517 miles	3,605,361 miles	334,310	906,811	4,605,595
TRU			25,700 hours	111,037 hours	19,018	82,168	123,465
Total			31,460,552 miles 26,520 hours	68,950,503 miles 112,820 hours	3,778,254	8,091,560	32,392,863

[a] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.

[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Highlights

- All PTD activated sites collectively achieved an impact of over 8 million gallons of petroleum displaced in the program to date.
- The heavy-duty vehicle sector accounted for nearly a third of the petroleum displaced in 2025 and is projected to account for more than 40% of the petroleum displaced over 10 years.
- Over a 10-year period, the current activated sites will displace over 32 million gallons of petroleum.

Greenhouse Gas and Criteria Pollutant Impact

The Evaluation Team calculated emissions reductions from displaced fossil fuel use from ICE vehicles that were not in service because of the Charge Ready Transport program. The Team developed ICE counterfactual equivalents for each market sector and then calculated the emissions associated with these

vehicles under conditions that otherwise matched the EVs to provide a baseline. Although EVs have no tailpipe emissions, the mix of generation sources from the electric grid used includes renewable as well as fossil fuel power to supply electricity to the charging stations, with the latter primarily responsible for emitting GHGs and criteria pollutants into the atmosphere.

Table 38 shows GHG impacts estimates for all sites in the program to date from the Charge Ready Transport program over three time periods: EY2025, the program to date, and a 10-year projection (based on annualized data from all sites).

Table 38. SCE Charge Ready Transport Program GHG Reductions Summary

Market Sector	Usage (n=115)				GHG Reduction (MT)		
	2025 Actual [a] kWh	PTD Actual [b] kWh	2025 Actual Use	PTD Actual Use	2025 Actual	PTD Actual	10-Year Projection
Forklift			820 hours	1,783 hours	7	16	53
Heavy-Duty Vehicle			10,930,684 miles	20,325,415 miles	14,281	25,373	132,308
Medium-Duty Vehicle			9,712,785 miles	24,081,945 miles	3,568	9,318	26,993
Port Cargo Truck			6,252,265 miles	12,481,430 miles	7,903	15,598	64,053
School Bus			3,176,781 miles	8,456,352 miles	3,096	8,081	24,095
Transit Bus			1,361,517 miles	3,605,361 miles	2,413	6,475	35,318
TRU			25,700 hours	111,037 hours	186	772	1,251
Total			31,434,032 miles 26,520 hours	68,950,503 miles 112,820 hours	31,455	65,633	284,071

[a] "2025 Actual" represents the data for EY2025 from all sites activated in the program to date.

[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Table 39 shows estimated local tailpipe emissions from ICE vehicles that the Charge Ready Transport program displaced. The transit bus market sector showed the highest reduction in CO emissions due to the assumption that the displaced buses ran on CNG. Our analysis also showed that TRU and heavy-duty vehicle sites produce a significant reduction in emissions relative to energy use because of the poor emissions profile of diesel-powered TRUs and yard tractors.

Table 39. SCE Charge Ready Transport Program Local Emissions Reductions, PTD Actual Sites

Market Sector	PTD Actual [a] (n=115)				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Forklift	2.2	2.3	2.1	2.6	104.4
Heavy-Duty Vehicle	532.9	319.5	304.3	1,511.5	14,981.9
Medium-Duty Vehicle	-	29.9	27.6	378.5	23,300.0
Port Cargo Truck	-	173.9	166.4	434.9	5,432.8
School Bus	-	19.4	18.6	86.2	2,453.1
Transit Bus	-	1.8	1.7	222.6	179,035.1
TRU	278.9	26.7	24.5	2,511.0	308.8
Total	814	573.3	545.1	5,147.3	225,616.1

[a] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Table 40 shows the same information as Table 39 for 2025 actual use. These are the localized emissions reductions that occurred based on actual Charge Ready Transport program operations this year.

Table 40. SCE Charge Ready Transport Program Local Emissions Reductions, 2025 Actual Sites

Market Sector	2025 Actual [a] (n=115)				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Forklift	1.1	1.1	1.0	1.3	48.5
Heavy-Duty Vehicle	421.4	188.3	179.1	993.3	9,230.7
Medium-Duty Vehicle	-	11.7	10.8	159.0	8,543.3
Port Cargo Truck	-	90.4	86.5	220.2	2,746.6
School Bus	-	7.5	7.2	33.1	932.8
Transit Bus	-	0.7	0.6	83.2	66,755.8
TRU	95.1	7.2	6.6	876.5	105.1
Total	517.5	306.9	291.8	2,366.6	88,362.9

[a] "2025 Actual" represents the data for EY2025 from all sites activated in the program to date.

Table 41 provides estimates of savings over the 10-year period. These are the annualized emissions reductions from all PTD sites extended over a decade. Again, transit buses show very high CO reduction, but a much smaller reduction of PM and ROG due to replacing CNG fueled vehicles. Heavy-duty vehicles account for more than 40% of the reduction in ROG and over 64% of the reduction in both PM_{10} and $PM_{2.5}$. TRUs account for approximately 41% of ROG reductions.

Table 41. SCE Charge Ready Transport Program Local Emissions Reductions, 10-Year Projected Impact for PTD Sites

Market Sector	PTD Sites 10-Year Projected Impact (n=115)				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Forklift	10.2	7.9	7.3	12.4	350.0
Heavy-Duty Vehicle	4,124.4	2,187.0	2,081.7	10,141.0	96,255.8
Medium-Duty Vehicle	-	87.3	80.6	1,481.1	68,938.0
Port Cargo Truck	-	979.3	936.9	1,626.1	19,393.8
School Bus	-	61.6	58.9	267.2	7,300.5
Transit Bus	-	11.3	10.8	1,170.1	920,910.4
TRU	1,056.4	62.5	57.5	10,281.9	1,162.8
Total	5,191.0	3,396.8	3,233.7	24,979.8	1,114,311.4

Table 42 shows GHG emissions from counterfactual vehicles, GHG emissions from the electricity used to charge the EVs, GHG emissions reductions, and percentage differences. Table 43 shows the net reductions of NO_X emissions from using EVs, based on the counterfactual and Utility emissions. The Evaluation Team estimated a total annualized GHG reduction of 84% and a NO_X reduction of 74% from the use of EVs compared with counterfactual vehicles for EY2025 sites. Reviewing the emissions for PTD sites reveals an estimated 80% reduction in GHG emissions and 82% reduction in NO_X emissions.

Table 42. SCE Charge Ready Transport Program Counterfactual GHG Reductions

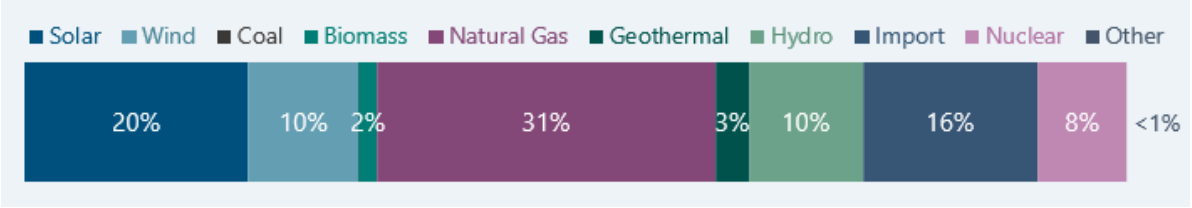
Market Sector	EY2025 Sites Annualized GHG (MT) (n=29)				PTD Sites GHG (MT) (n=115)			
	Counter factual	Utility	Reduction	% GHG Reduction	Counter factual	Utility	Reduction	% GHG Reduction
Forklift	-	-	-	None	18.9	2.9	16.0	84%
Heavy-Duty Vehicle	4,978.5	836.3	4,142.1	83%	31,990.9	6,617.8	25,373.1	79%
Medium-Duty Vehicle	192.3	36.7	155.6	81%	11,453.4	2,135.5	9,318.0	81%
Port Cargo Truck	93.6	15.2	78.4	84%	19,547.9	3,949.7	15,598.2	80%
School Bus	767.6	103.3	664.3	87%	9,826.5	1,745.9	8,080.7	82%
Transit Bus	2,463.0	392.3	2,070.7	84%	7,934.2	1,459.0	6,475.2	82%
TRU	14.3	2.3	12.0	84%	920.5	148.9	771.5	84%
Total	8,509.2	1,386.1	7,123.2	84%	81,692.4	16,059.8	65,632.6	80%

Table 43. SCE Charge Ready Transport Program Counterfactual NO_X Reductions

Market Sector	EY2025 Sites Annualized NO_X (kg) (n=29)				PTD Sites NO_x (kg) (n=115)			
	Counter factual	Utility	Reduction	% NO_X Reduction	Counter factual	Utility	Reduction	% NO_X Reduction
Forklift	-	-	-	None	24.6	2.4	22.2	90%
Heavy-Duty Vehicle	3,726.3	681.9	3,044.4	82%	38,815.4	5,362.3	33,453.1	86%
Medium-Duty Vehicle	13.5	29.9	(16.4)	None	1,659.9	1,758.0	(98.1)	None
Port Cargo Truck	64.5	12.7	51.8	80%	19,208.3	3,225.8	15,982.6	83%
School Bus	432.3	85.2	347.1	80%	8,805.3	1,456.6	7,348.7	83%
Transit Bus	114.3	323.0	(208.7)	None	395.9	1,206.2	(810.3)	None
TRU	57.2	1.8	55.4	97%	3,747.6	126.2	3,621.4	97%
Total	4,408.0	1,134.4	3,273.6	74%	72,657.0	13,137.4	59,519.6	82%

Figure 109 shows the net electricity generation mix in the program to date during the hours when the EVs were charging. The CAISO grid mix continually changes depending on factors that include the level of total demand for power on the grid and the availability of fossil generation and variable renewable resources such as solar.

Figure 109. SCE Charge Ready Transport Program Net Electricity Mix, PTD



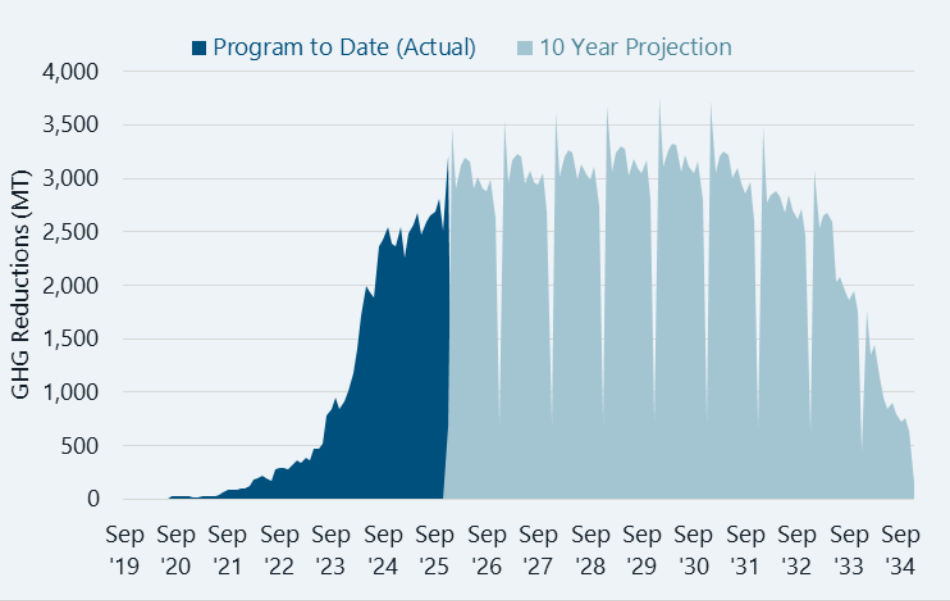
Approximately 16% of the grid mix comprises electricity imports, which do not vary by time of day for analysis purposes, but which match the resource mix purchased for the California grid.[61]

Based on the real-time grid conditions when charging occurred, the overall energy mix comprised 53% zero-emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 31% natural gas. The Evaluation Team expects emissions reductions from these sites over 10 years to increase as the grid becomes cleaner. Additionally, the increased use of managed charging will reduce emissions as EVs charge at off-peak periods and during times when the grid is supplied with greater amounts of renewable generation. Emissions will further decrease with the addition of more charging sites and EVs in future evaluation years.

Figure 110 shows how GHG emissions reductions have increased as a result of the Charge Ready Transport program and how these reductions are likely to grow over time for all operational sites. The analysis period ranges from the activation date of the first site in the program through the end of 2025. The analysis incorporates the net reduction (counterfactual emissions minus Utility emissions) for each fleet within the SCE Charge Ready Transport program. Emissions reductions from PTD sites appear in dark blue, and anticipated benefits based on annualization appear in a lighter blue. Because sites begin operations at different times, the 10-year sunset for each appears as a gradual tapering of program benefits between 2030 and 2034. This taper reflects that benefits are no longer counted after 10 years, although fleets will likely continue to use the infrastructure. While each year's operations appear similar, there are several key factors driving the slight variations such as seasonality of Utility generation sources (high Utility emissions will appear as a dip on the curves), holidays occurring on weekends versus weekdays, and extrapolation for sites that became operational late in 2025 and will operate year-round in future years.

[61] The power associated with imports comes from a mixture of renewables, hydro, nuclear, and natural gas power plants located outside of California (www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation).

Figure 110. SCE Charge Ready Transport Program Historical and Forecasted GHG Reductions for PTD Sites



Highlights

- Program-to-date results for the Charge Ready Transport program show an 80% reduction in GHG emissions and an 82% reduction in NO_X emissions.
- The greatest reduction in local emissions was for CO, showing an estimated reduction of more than 88,000 kg in 2025 and a projected 10-year reduction of more than 1.1 million kg.
- Based on the real-time grid conditions when EV charging occurred, the overall energy mix contained about 53% zero-emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 31% natural gas.

Health Impacts

The Evaluation Team calculated public health impacts (as benefits and costs) of reductions in criteria pollutants from vehicle electrification. The pollutants included in the analysis are primary $PM_{2.5}$ and precursors of secondary $PM_{2.5}$, including NO_X, sulfur dioxide (SO_2), ammonia (NH_3), and VOCs. This analysis considered only tailpipe emissions reductions rather than full lifecycle emissions (such as power plant emissions). The Evaluation Team used the EPA CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) to evaluate the health benefits associated with the emissions reductions. COBRA estimates the county-level, monetized benefits for the county in which emissions are reduced. The tool also estimates the monetized benefits for all counties in the United States (since emissions disperse beyond the county of the source), although most impacts are felt within nearby counties and our analysis only examines California counties.

The morbidity-related monetary benefits include avoided lost wages, avoided medical costs, and the money people are willing to pay to avoid an illness or condition like a respiratory disease. The mortality-related monetary benefits are measured by the value of a statistical life associated with premature mortality. COBRA reports both a low and high impact for mortality, representing the uncertainties in the estimates.

The total value of the health benefits associated with emissions reductions from the Charge Ready Transport program for activated PTD sites is between $6,247,660 and $8,147,824—nearly double the total value from last year's evaluation's report. Table 44 shows the health benefits in California broken down by health endpoint.

Table 44. SCE Charge Ready Transport Program California Health Benefits for PTD Sites in 2025

Health Endpoint	Change in Incidence (Annual Cases)		Monetary Value (Annual, 2025 Dollars)	
	Low	High	Low	High
Mortality	**0.36**	**0.486**	**$5,403,479**	**$7,303,643**
Avoided Medical Care				
Hospitalization, Respiratory	0.045	0.045	$839	$839
Hospitalization, Cardiovascular	0.018	0.018	$537	$537
Hospitalization, Other	0.056	0.056	$1,317	$1,317
ER Visits, Respiratory	0.853	0.853	$1,422	$1,422
ER Visits, Cardiovascular	0.036	0.036	$79	$79
Out of Hospital Heart Attacks	0.002	0.002	$24	$124
Nonfatal Heart Attacks	0.085	0.085	$7,372	$7,372
Stroke	0.008	0.008	$491	$491
Lung Cancer	0.009	0.009	$428	$428
Asthma	450.689	450.689	$377,126	$377,126
Hay Fever	18.417	18.417	$21,124	$21,124
Lost Productivity				
Minor Restricted Activity Days	115.3	115.3	$14,923	$14,923
Work Loss Days	19.599	19.599	$6,383	$6,383
School Loss Days	235.658	235.658	$412,017	$412,017
Total Health Effects	-	–	$6,247,660	$8,147,824

At the site level, sites in the heavy-duty vehicle market sector accounted for 77% of the monetary value from benefits, followed by the school bus (9%), medium-duty vehicle (7%), TRU (6%), and transit bus market sectors (1%).

As part of this analysis, the Evaluation Team also examined health benefits within DACs, which may be disproportionately burdened by sources of pollution (including air pollution from ICE vehicles). Because COBRA estimates effects at only the county level, the Evaluation Team disaggregated the health benefits by census tract using the relative population of each tract from the most recent American Community Survey (ACS). For example, we allocated 10% of the value of the health benefits to a census tract with 10% of the county's population. The Evaluation Team then estimated the total benefits allocated to DACs and

non-DACs.[62] This approach assumes that the benefits of emissions reductions are distributed evenly throughout the county. If the sites reside in DACs, and the emissions reductions are greater in the tracts near the sites, this approach understates the potential benefit to DACs. Additional information about emissions dispersion within counties would provide more precise estimates of health benefits to DACs and non-DACs.

In our analysis, Los Angeles County had 56% of the total benefits, followed by Orange County (12%), San Bernadino (9%), Riverside County (8%), and San Diego County (6%). Overall, 31% of the total benefits are in DACs.

Highlights

- Cumulative health benefit results in California realized by the Charge Ready Transport sites in terms of monetary benefits range from $6,247,660 for the low estimate and $8,147,824 for the high estimate.
- Sites in the heavy-duty vehicle market sector had the highest health benefits overall.
- Los Angeles County had the highest proportion of overall impacts at 56%, followed by Orange County (12%), San Bernadino (9%), Riverside County (8%), and San Diego County (6%).
- The proportion of overall benefits attributed to DACs for the program to date is 31%.

Net Impacts

As part of the net impacts analysis, the Evaluation Team estimated program effects on participants to exclude impacts from actions that participants would have taken without the program (freeridership) and to include any program attributable indirect impacts on participants (participant spillover).

Enhanced Self-Report

The Evaluation Team based the enhanced self-report NTG analysis for the MDHD programs on information gathered through in-depth surveys with participating fleet managers. The Evaluation Team created the survey via an online survey platform, Qualtrics, and provided a link to the survey during or following site visits that the Team conducted. The Evaluation Team used the CPUC nonresidential customer self-report NTG framework originally developed for energy efficiency programs as the base for the MDHD fleet manager NTG methodology approach.[63] *Appendix B* provides more detail about the MDHD fleet manager self-report NTG methodology.

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62 DAC census tracts are defined as those included in the SB 535 Disadvantaged Communities List (2022), which includes DAC categories for CalEnviroScreen 4.0 Top 25%, CalEnviroScreen 4.0 High Pollution Burden Score and Low Population Count, and 2017 Disadvantaged Community (CalEnviroScreen 3.0 only).

63 California Public Utilities Commission, Energy Division. February 20, 2015. Methodological Framework for Using the Self-Report Approach to Estimating Net-to-Gross Ratios for Nonresidential Customers.

The Evaluation Team estimated the core component of the CPUC NTG methodology through three program attribution index (PAI) site scores (PAI-1A, PAI-2, and PAI-3). The Team used three separate sets of questions to assess the three components of the core NTG ratio, with each PAI score on a scale of 0.0 to 1.0 representing a different way of characterizing the Charge Ready Transport program influence. The analysis included fleet manager responses from nine of the 25 participating sites that were provided with a link to the survey.[64]

The Evaluation Team calculated the resulting self-report NTG for each site prior to accounting for participant spillover, as the average of the three PAI scores. The average PAI scores across all sites surveyed resulted in an overall core NTG ratio of 0.42, presented in Table 45. One minus the overall core NTG ratio of 0.42 equals the 0.58 freeridership ratio for the Charge Ready Transport program.

None of the surveyed sites reported electrifying more of their fleets since participating in the Charge Ready Transport program, without the benefit of funding from the program or another organization and where their program participation was important in the additional purchasing decision. Therefore, the participant spillover analysis found that the participant spillover ratio is 0.00. The final program-level NTG ratio of 0.42 for the SCE Charge Ready Transport program sites surveyed equals one minus the freeridership ratio plus the participant spillover ratio presented in Table 45. The EY2025 NTG ratio of 0.42 is lower than the EY2024 NTG ratio of 0.57 and higher than the EY2023 NTG ratio of 0.38. This indicates that the Charge Ready Transport program had less influence on the decision to complete transportation electrification projects for the fleets surveyed in EY2025, in comparison to fleets surveyed in EY2024, but had greater influence than on those fleets surveyed in EY2023.

Table 45. SCE Charge Ready Transport Program NTG Fleet Manager Analysis Results in EY2025

Fleet Manager Survey Completes [a]	Average of PAI-1A Score NTG	Average of PAI-2 Score NTG	Average of PAI-3 Score NTG	Core NTG Ratio	Free-ridership Ratio	Participant Spillover Ratio	Final NTG Ratio
9	0.49	0.34	0.44	0.42	0.58	0.00	0.42

[a] The survey results are based on a low respondent count, which limits the reliability of the findings and precludes statistical significance; therefore, results should be viewed as indicative rather than conclusive.

Highlights

- The EY2025 program-level freeridership ratio is 0.58 with a 0.00 participant spillover ratio, which resulted in a program-level NTG ratio of 0.42.
- The EY2025 NTG ratio of 0.42 (n=9) is lower than the EY2024 NTG ratio of 0.57 (n=13) and higher than the EY2023 NTG ratio of 0.38 (n=5). This indicates that the Charge Ready Transport program had less influence on the decision to complete transportation electrification projects for fleets surveyed in EY2025 than for fleets surveyed in EY2024 but had greater influence on fleets surveyed in EY2023.

64 Respondents from three heavy-duty vehicle sites, two school bus sites, one medium-duty vehicle site, one transit bus site, one forklift site, and one port cargo truck site completed the NTG questions in the survey. One school bus respondent did not complete the NTG questions and was not included in the NTG analysis.

4.1.3. Lessons Learned

In 2025, SCE staff continued to support customers through an increasingly complex regulatory and market environment as new federal policy changes and market disruptions compounded existing challenges. As in previous evaluation years, regulatory uncertainty and market pressures remained significant barriers for SCE staff and customers. Several new developments added complexity to an already difficult operating environment.

- **Reduced regulatory incentives:** CARB's withdrawal of the ACF waiver in January 2025 weakened the regulatory incentive for many customers to electrify their fleets, contributing to broader customer hesitation.
- **Tariffs and procurement uncertainty:** New federal tariffs created uncertainty around the cost and availability of infrastructure components sourced from outside the United States.
- **Federal funding compliance:** Build America, Buy America (BABA) requirements introduced additional compliance complexity for customers receiving federal funding.
- **Vendor instability:** Closures among EV and EVSE companies delayed site construction and vehicle delivery and disrupted project timelines.
- **Permitting delays:** Inconsistent requirements from self-permitting agencies and delays related to DSA review continued to slow site delivery, consistent with challenges reported in prior years.
- **Evolving charging standards:** The shift in EV manufacturer port standards from CCS to NACS created additional uncertainty for customers planning sites.

Through these changes, SCE staff helped customers understand and navigate new obligations and risks. When vendor instability disrupted sites, staff helped customers identify replacement vendors. SCE staff also responded to charging standard uncertainty by requesting a temporary deviation from the CPUC. Approved in September 2025, this deviation allowed customers using non-ISO 15118-compliant chargers for Tesla Semi vehicles to continue to use these chargers until a compliant charger was added to the APL.

Building on improvements developed over multiple program years, SCE staff introduced targeted changes in 2025 to reduce site delivery delays, strengthen construction oversight, and continue building the institutional knowledge needed to support future MDHD fleet programs. As in prior evaluation years, SCE staff refined and implemented process changes to improve site delivery. In 2025, staff shifted several steps earlier in the timeline to reduce avoidable delays and keep sites moving within program windows; these changes included ordering switchgear when a site entered permitting rather than waiting until design completion, initiating engineering consultations and environmental reviews earlier in the process to maintain momentum before program windows closed; and creating a Behind-the-Meter Manager role to coordinate contractors across five general contractors and implement added safety and quality checkpoints.

These changes improved operational efficiency across sites and helped SCE staff build substantial institutional expertise and practical tools. As the Charge Ready Transport program approaches its conclusion, that knowledge base will continue to support future MDHD fleet programs and SCE's TEAS program.

As the Charge Ready Transport program has matured, SCE staff have drawn on fleet success stories and program experience to build customer confidence and help prospective participants better understand the electrification process. In 2025, SCE staff continued strengthening customer-facing processes to improve communication and overall project flow. The following refinements helped customers better understand site requirements, anticipate changes, and move through the process with greater confidence.

- **Structured post-design meetings:** Staff organized meetings between construction management teams and customers following the design phase to keep all parties aligned on site status and customer requirements.
- **Earlier identification of common site changes:** Drawing on lessons from previously completed sites, staff identified recurring categories of site changes earlier in the process so customers could address them without repeating steps in the process.
- **Use of participant success stories:** As more fleets completed electrification projects and shared their experiences, these examples became increasingly valuable for helping prospective customers understand project scope and approach electrification with greater confidence.

The Charge Ready Transport program continues to displace petroleum, reduce GHG and local emissions, and provide health impacts. Charge Ready Transport program sites have displaced more than eight million gallons of petroleum in the program to date, with heavy-duty vehicle sites alone accounting for over three million gallons. In addition, the program has resulted in a reduction of over 65,000 MT of GHG emissions to date. These sites have all positively contributed to lowering local emissions, with CO reduction being the most prominent, achieving a reduction of 225,616 kg to date Overall, 31% of the health benefits from PTD sites are in DACs, and the total monetized health benefits from these sites range from $6,247,660 to $8,147,824.

Fleet managers remain motivated to participate in the Charge Ready Transport program and report meaningful benefits from their participation, but costs continue to present a significant barrier even among those satisfied with their overall program experience. As in previous years, fleet managers said they were motivated to participate in the Charge Ready Transport program primarily by regulatory requirements (8 of 10), environmental benefits (7 of 10), and available rebates and incentives (7 of 10). Fleet managers reported two types of costs: charging infrastructure costs (which was a notable barrier before participation for seven of 10 fleet managers but was not cited as a barrier after participation) and vehicle purchase costs. The cost of EVs remained a concern both before and after participation, cited by seven of 10 fleet managers before participation and five of 10 after.

In addition to continued concerns about cost, fleet managers reported several financial and community-related benefits of electrification. Most respondents (8 of 10) said they expected the transition to electrification to benefit their fleet or community. Fleet managers cited community benefits, in particular reduced noise pollution (5 of 9) and improved air quality (4 of 9) and operational savings, including lower vehicle fueling costs (6 of 9) and reduced maintenance costs (4 of 9). Finally, nearly all (9 of 10) fleet mangers indicated they were *very satisfied* or *somewhat satisfied* with their overall program experience.

A continued shift toward larger heavy-duty vehicle sites increased costs on a per-site and per-vehicle basis, but reduced costs per installed kilowatt. The average installed charging capacity per site was 1,033 kW through 2025 compared with 758 kW through 2024. The average Utility infrastructure cost was $467,715 per site and $44,782 per vehicle through 2025 compared with $430,204 per site, $36,450 per vehicle through 2024. However, costs per kilowatt of charging capacity installed remained similar at $1,119 through 2025 compared with $1,158 through 2024. The school bus market sector now accounts for 37% of all financially closed out sites in the Charge Ready Transport program. Total all-in costs paid by SCE and the customer including TTM and BTM increased, rising to an average of $869,600 per site in the program, compared with $802,698 per site through 2024.

Site activation timelines continued to increase significantly relative to earlier evaluation years driven by large, more complex heavy-duty vehicle sites; the design and permitting phase accounts for over one-third of project durations. The overall median number of calendar days from application to activation was 1,228 days in EY2025, increasing significantly from 959 days in EY2024, and 869 days in the program to date. The design and permitting phase has been the longest in duration across all evaluation years, taking 429 days in EY2025, an increase from 395 in EY2024 and 288 days in the program to date. However, the construction and activation phases saw the greatest increases in duration, with construction rising from 150 days in EY2024 to 189 days in EY2025, an increase of 25%, compared with 140 days in the program to date. The activation phase rose from 19 days in EY2024 to 83 days in EY2025, an increase of 320%, compared with 43 days in the program to date. Other program phases remained similar between EY2024 and EY2025. Approximately 28% of sites began charging sessions within 30 days of power availability, while nearly 35% took over 120 days, similar to EY2024.

The Evaluation Team attributes longer site activation timelines to several factors, most prominently that many sites activated in 2025 are large and complex. Over 40% of sites activated in EY2025 were in the heavy-duty vehicle market sector (12 of 29), which has a higher average installed capacity than other market sectors; sites in this market sector are more time-consuming to complete. Additionally, now that the Charge Ready Transport program is in its second half, sites with longer lead times are coming online, whereas in early years of the program sites with shorter lead times came online.

The Charge Ready Transport program lags behind its goals for number of sites and vehicles, and program spending remains low, but DAC spending remains above target. In EY2025, 29 sites with 445 charging ports were activated supporting 909 vehicles, based on VAPs of activated sites. Of the six market sectors the program supports, the heavy-duty vehicle market sector became the most common in EY2025 (accounting for 41% of sites), surpassing the school bus market sector for the first time since program inception. This shows greater diversity in the participant pool and indicates a trend toward larger sites. The 260 contracts signed in the program to date meets 52% of the program's per se reasonableness site goal. The 260 contracts signed would support 5,296 MDHD vehicles, which meets 62% of the program's per se reasonableness electrified vehicles goal.

Program spending in EY2025 totaled $14.5 million, which is 29% lower than the $20.5 million spent in EY2024. This brings total program spending to $64.5 million of the approved budget of $342.6 million, or 19% of programmatic funding. The total spending includes only activated sites that have been fully

financially closed out and does not include funding reserved for contracted sites. The percentage of program spending on infrastructure for sites located within a DAC was 68%, exceeding the 40% program target.

Though overall consumption increased significantly, peak demand represents a small portion of installed charging capacity. A total of 41 MW of new charging capacity was activated in the Charge Ready Transport program in EY2025, bringing total installed capacity to 131 MW for PTD sites. Overall consumption in EY2025 was nearly 50 MWh, a small increase over more than 45 MWh in EY2024. However, peak demand reached over 20 MW in EY2025, up from 14.5 MW in EY2024, which is an increase of 38%. On-peak utilization dropped slightly to 15.7% of all energy consumed in EY2025, up from 16.1% in EY2024 and 17.3% in the program to date.

Few fleets are using load management, so a significant opportunity exists for fleets to reduce costs and GHG emissions. A total of 21 of the 115 PTD operational sites (18%) showed evidence of load management usage in EY2025. This is the same number of sites that showed evidence of load management in EY2024, despite an additional 29 being activated in EY2025.

On a monthly basis, 47% of transit bus charging, 42% of school bus charging, 41% of heavy-duty vehicle charging, and 24% of medium-duty vehicle charging sessions show enough flexibility to shift to lower-cost and lower-emissions time periods using load management. Potential savings through use of load management could be as high as $563,000 annually per site for non-load-managed sites and $188,000 for sites already using some degree of load management. On average, PTD activated sites can reduce current GHG emissions by 14% by avoiding energy consumption from 4 p.m. to 9 p.m. while maintaining or decreasing costs.

Not all NSPs offer load management capability, and only 10 of 30 NSPs operating in the Charge Ready Transport program have customers that consistently use load management. During site visits, the Evaluation Team determined that most fleet operators were aware of TOU pricing, but many fleet operators lacked direct access to their utility bills to understand TOU cost impacts, and many operators expected their average electricity costs to be lower than the actual cost data presented by the Evaluation Team.

Across 1,541 billing months for Charge Ready Transport program sites, the best results show average monthly electricity costs of approximately $0.20/kWh through use of load management, and 44% of monthly billing has an average cost below $0.30/kWh. Eight percent of sites see billing months with costs greater than $1.00/kWh, though most of these high energy-cost billing months are from sites with very low usage, and therefore monthly fees are spread across a small number of kilowatt-hours. Larger sites tend to have lower electricity costs, because these sites are more likely to use load management and because monthly fees are spread across a larger number of kilowatt-hours.

4.2. Schools and Parks Pilots

4.2.1. Overview

This overview provides a detailed description of the SCE Schools and Parks Pilots; summaries of the pilot implementation process, performance metrics, program materials, and budget; and a timeline of major milestones. Following the overview are detailed findings, highlights, and lessons learned.

Pilot Description

Schools Pilot: Per Decision 19-11-017, SCE's Schools Pilot (Charge Ready Schools) offers direct installation of and incentives for installing approximately 250 L2 ports at 40 K–12 schools. SCE staff designed the pilot to enable K–12 schools to offer public charging to not only school staff, but also the local community.

Schools Pilot Targets

- 250 L2 ports
- 40 K–12 schools
- 40% in DAC locations

Participating schools can opt to install SCE-owned EVSE or own the EVSE themselves.[65] For sites where SCE owns the EVSE, SCE also operates and maintains the EVSE; however, the site host is still required to prepare the site for make-ready deployment (such as easement) and to pay all electricity charges. If the site host chooses to own the EVSE, SCE offers a rebate based on the market costs for each type of charger. At the time of the Decision this rebate was up to $2,000 per port for L1 and L2 chargers. However, before the Schools Pilot launched, staff adjusted the incentive approach to ensure that sites choosing the ownership option would receive the same benefits as those choosing to have SCE own the EVSE. This adjustment maintains a static cost for the EVSE but also considers the required agreement to operate and maintain the equipment, warranty, and network fees for eight years. As a result of this change, the Schools Pilot rebate does not support DCFC. As per the Decision, SCE staff offer customers an option to manage and pay for qualified state-licensed labor to install customer-side infrastructure, for which SCE provides a rebate of up to 100% of the installation cost. Participating schools also commit to providing charging equipment usage data for a minimum of eight years.

Schools Pilot Design Goal

Empower K–12 schools to offer public charging to staff, students, parents, and the greater community.

SCE also worked with the Energy Coalition (TEC) staff to develop a K–12 Campus EV Awareness Campaign in 2022. The campaign officially launched in March of 2023 and continued to be rolled out in 2024.

[65] Two SCE Schools Pilot site hosts chose this option.

Parks Pilot: SCE staff designed the Parks Pilot to encourage state parks and beaches to charge their own EV fleets and to offer charging services to staff and patrons with LDVs. Per Decision 19-11-017, SCE planned to offer direct installation of approximately 120 L2, 10 DCFC, and an optional 15 mobile chargers across 27 state parks and beaches. After signing a master participation agreement (MPA) in 2022 and further exploring site viability, SCE requested an adjustment to the Parks Pilot's goals per AL 4926-E-A (approved in 2023) that would reduce the state parks and beach target to "up to 21 sites" and augment the DAC location requirement to include DAC-adjacent locations.[66] In 2025, SCE submitted a site addendum to the MPA to alter the port count of one site from two DCFC ports to 15 L2 ports due to a viability issue.

Original Parks Pilot Targets

- 120 L2, 10 DCFC, and 15 optional mobile charging stations
- 27 state parks and beaches
- 25% in DAC locations

2023 Updated Parks Pilot Targets

- Up to 21 state parks and beaches
- 25% in DAC and DAC-adjacent locations

SCE owns, builds, and operates the EVSE and contracts with a third-party vendor who is responsible for all electricity costs to serve as the customer of record for the chargers. The third-party vendor is required to participate in a demand response program and to report the prices it passes on to the EV drivers.

Parks Pilot Design Goal

Encourage state parks and beaches to charge their own EV fleets and to offer charging to staff and patrons with LDVs.

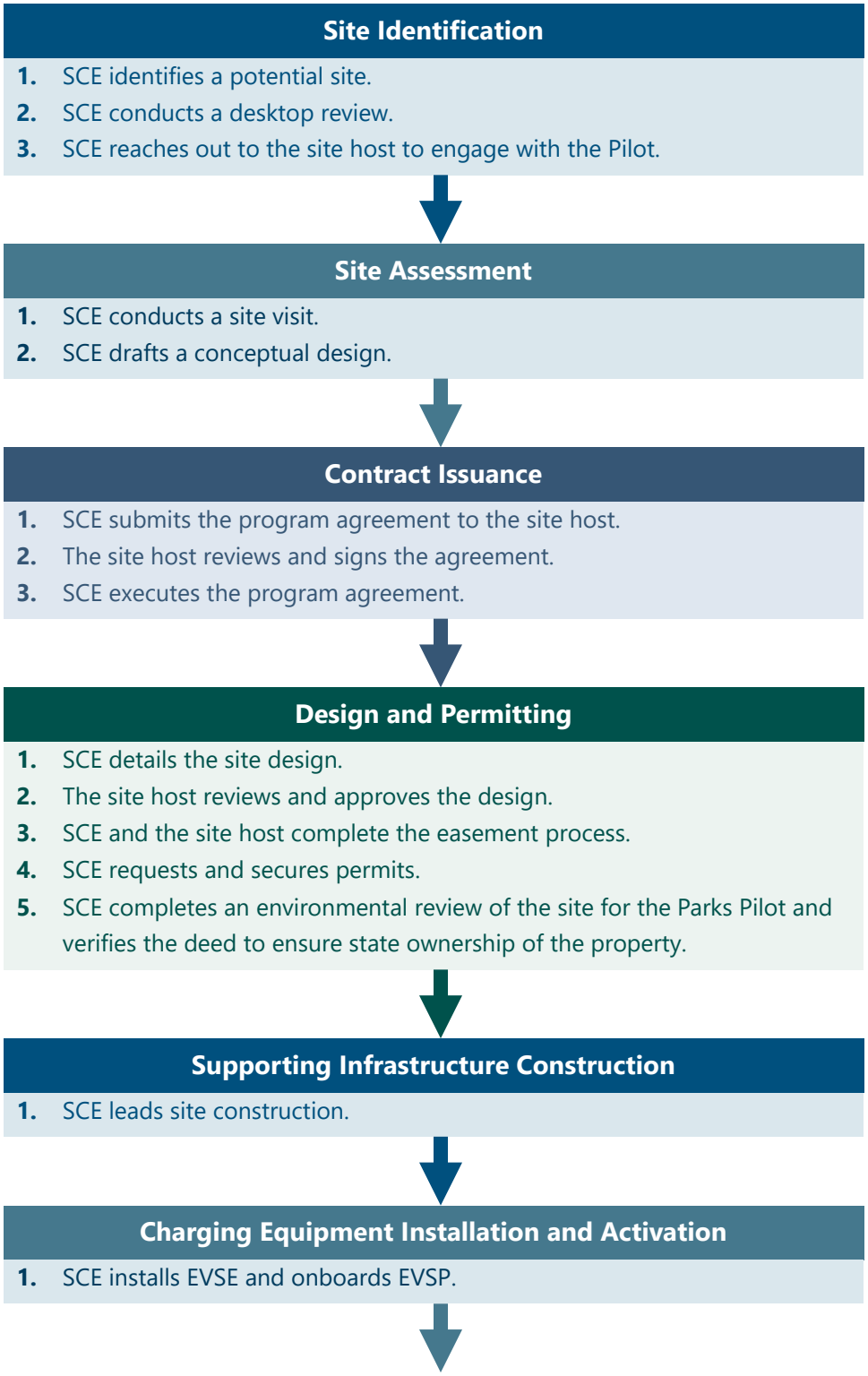
SCE staff had planned to deploy a customer marketing campaign in 2024 to publicize the availability of EV charging stations, with the goals of facilitating EV adoption by reducing range anxiety and encouraging park patrons to drive EVs to parks or beaches with EVSE. As no sites were completed in 2024 or 2025, this campaign has been delayed until sites are ready for promotion, which will likely happen in 2026.

Implementation

Figure 111 shows the implementation process for the Schools and Parks Pilots from site identification to close-out. The Schools Pilot is complete, and all sites have undergone the close-out stage. The Contract Issuance step is slightly different for the Parks Pilot, since the California Department of Parks and Recreation (DPR) approved the MPA in 2022 that applies to all state parks in SCE service territory participating in the Parks Pilot. Each individual site required site addendums to the MPA based on specific site needs and designs.

[66] As noted in EY2023 and EY2024, according to close-out interviews with Utility staff, SCE and the DPR moved forward with nine sites as they determined that these nine sites would be sufficient for SCE to achieve the port goal.

Figure 111. SCE Schools and Parks Pilots Implementation Process



Close-Out
1. The site host is onboarded with EVSP 2. SCE issues the rebate (if applicable). 3. The site host commits to port-level data sharing for eight years. 4. If the charging equipment is customer owned, the site host commits to maintaining and operating charging equipment for eight years. If SCE owned, SCE maintains and operates equipment for eight years.

Program Performance Metrics

The Evaluation Team analyzed sites participating in the SCE Schools Pilot by site status. Table 46 provides the count of SCE Schools Pilot sites by completion status in EY2025 and for the pilot to date. SCE did not activate or complete construction of any Parks Pilot sites in EY2025.

Table 46. SCE Schools Pilot Total Site Count by Status

Site Status	EY2025	Pilot to Date
Utility Construction Complete	5	30
Activated	8	30
Operational	9	30
Closed Out	2	21

In EY2025, eight sites were activated in the SCE Schools Pilot as shown in Figure 112. These sites also became operational, along with one older site, for a total of nine operational sites in EY2025. In total, 30 contracts have been signed in the pilot to date, with no additional contracts signed in EY2025.

Figure 112. SCE Schools Pilot EY2025 Activated Charging Stations

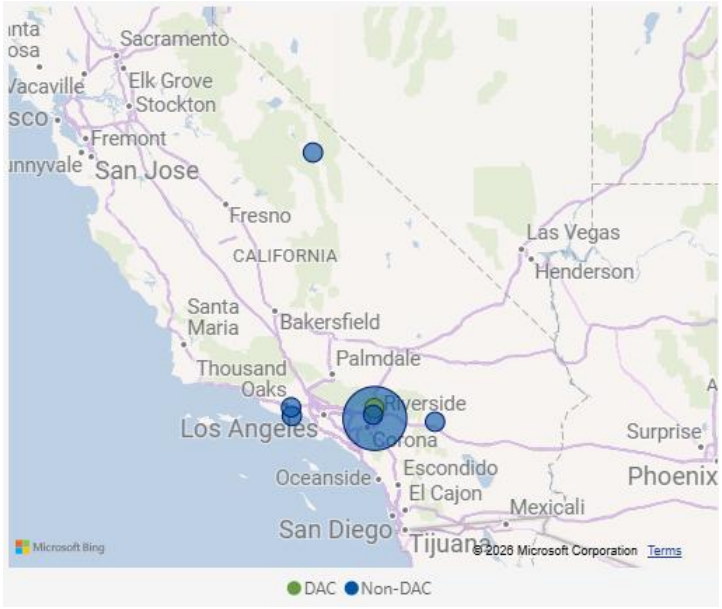


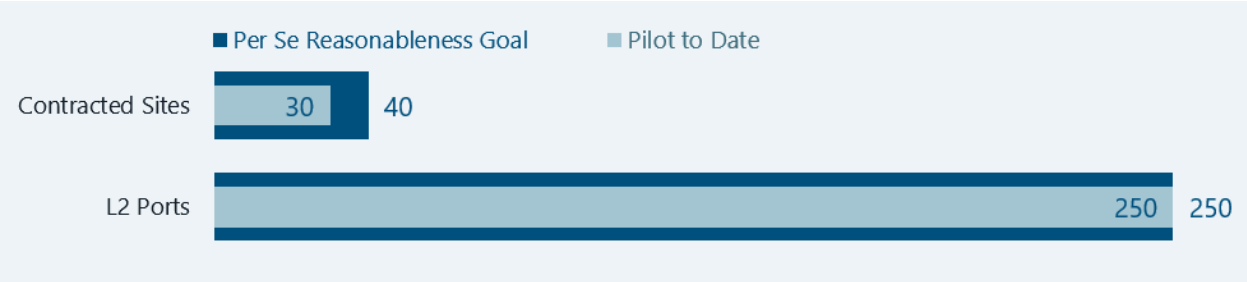
Table 47 presents site-level data for the SCE Schools Pilot, showing DAC status and number of L2 ports for the activated sites in EY2025 and for the pilot to date. Three of the eight sites activated in 2025 are in a DAC. This brings the cumulative percentage of DAC sites to 53%, exceeding the pilot's per se reasonableness DAC goal of 40% of sites. With the addition of 78 ports in EY2025, the total number of installed ports in the pilot to date is 250 L2 charging ports.

Table 47. SCE Schools Pilot Activated Site Data in EY2025 and Pilot to Date

EY2025			Pilot to Date		
Number of Activated Sites inside DAC	Number of Activated Sites outside DAC	Number of L2 Charging Ports	Number of Activated Sites inside DAC	Number of Activated Sites outside DAC	Number of L2 Charging Ports
3	5	78	16	14	250

As shown in Figure 113, the 30 contracted sites in the SCE Schools Pilot meet 75% of the Schools Pilot's per se reasonableness goal of 40 sites. The 250 L2 ports at the contracted sites meet 100% of the pilot's per se reasonableness goal of 250 L2 charging ports.

Figure 113. SCE Schools Pilot Site and Port Per Se Reasonableness Goal Progress



The CPUC established six phases in the program timeline per the SB 350 reporting template. Table 48 shows the median durations by program phase for EY2025 and pilot-to-date activated sites. The median number of calendar days per program phase for EY2025 sites in the Schools Pilot ranged from 0 days for activation to 170 days for construction complete.

Table 48. SCE Schools Pilot Median Calendar Days per Phase

CPUC Program Phase	Median Calendar Days	
	EY2025 [c]	Pilot to Date [d]
Application Review [a]	-	63
Site Assessment [a]	-	38
Contract Issuance [a]	-	20
Design and Permitting [a]	-	403
Construction Complete	170	130
Activation [b]	0	0

[a] Duration data for this phase was not available at the time of report writing.
[b] SCE considers Schools Pilot sites to be activated as soon as site construction is complete.
[c] "EY2025" represents the data for the sites activated in 2025.
[d] "Pilot to Date" represents the data from all activated sites from program inception for all program years.

Program Materials Summary

Schools Pilot: SCE launched the Schools Pilot curriculum in 2023 in partnership with TEC. The curriculum comprises grade-level-specific materials to provide educators with tools and resources to effectively teach their students the nuances of electrification and EV ownership.[67] The curriculum continued through June 2025, with 17 educators enrolled from 11 different schools reaching approximately 2,000 students.

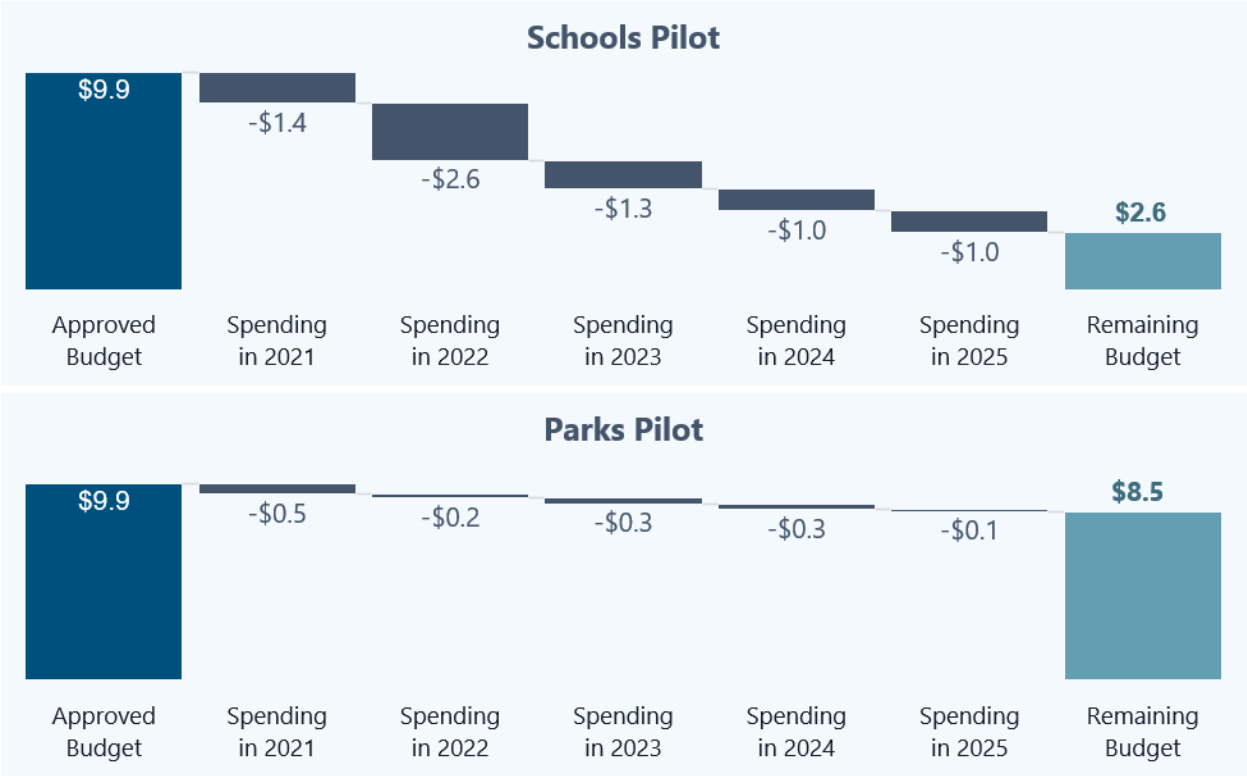
Parks Pilot: SCE did not conduct any marketing or outreach activities specifically for the Parks Pilot in 2025.

Budget Summary

As shown in Figure 114, through the end of 2025, SCE spent $7.3 million (constant dollars) of the Schools Pilot's $9.9 million budget and $1.4 million (constant dollars) of the Parks Pilot's $9.9 million budget. SCE spent $1.0 million of the Schools Pilot budget and $0.1 million of the Parks Pilot budget in 2025. Through 2025, the Schools Pilot continued to outspend the Parks Pilot as the Schools Pilot completed construction of all sites, while Parks Pilot sites were still being planned in 2025.

[67] The 2023 evaluation report provides additional detail about the curriculum and outreach materials: www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/sb-350-te/srp-ab10821083-2023-evaluation-report112024.pdf

Figure 114. SCE Schools and Parks Pilots Budget (Millions USD) as of December 31, 2025

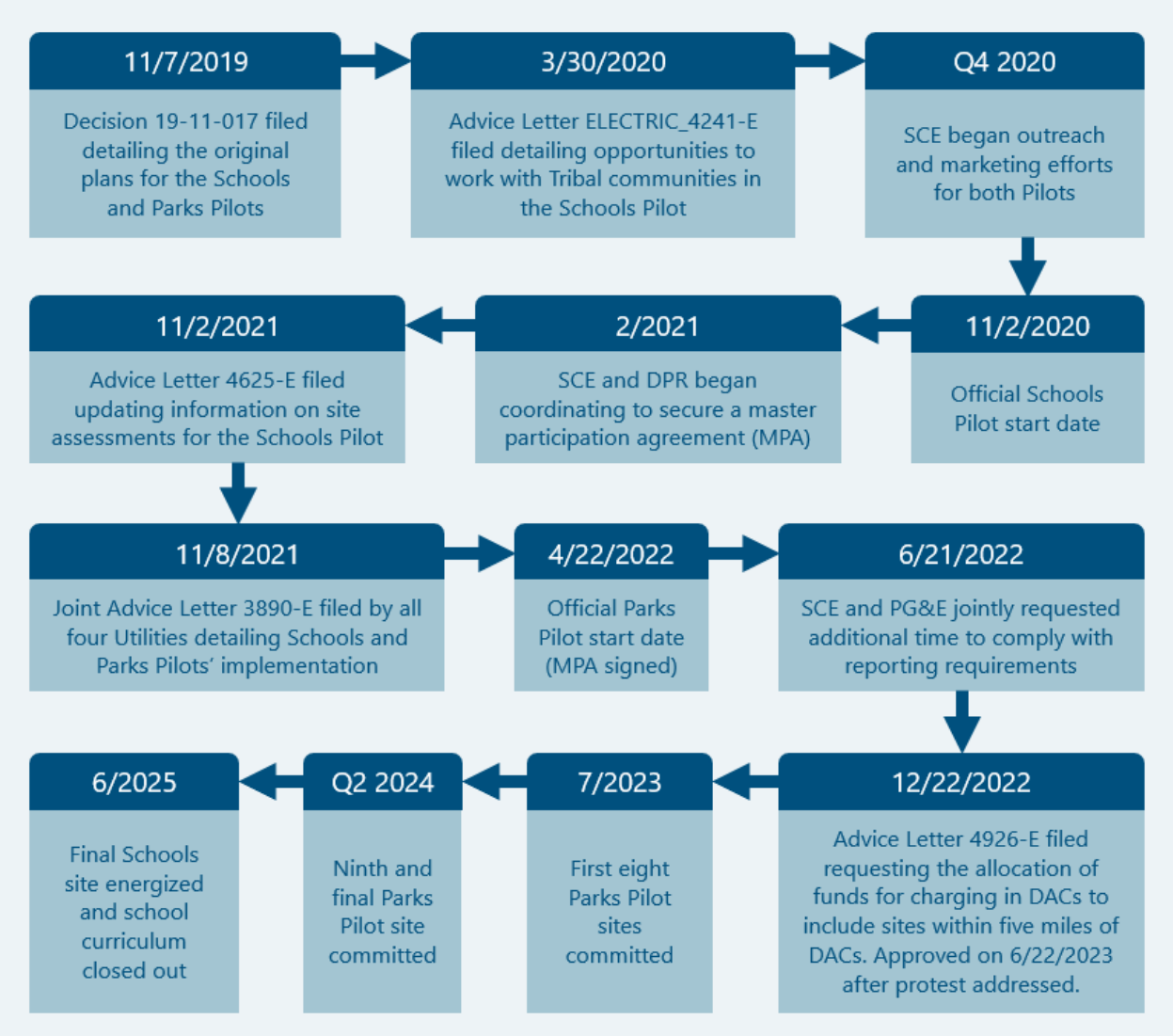


Timeline

Since the beginning of the Pilots, SCE has filed five Advice Letters: three pertaining to only the Schools Pilot and two pertaining to both the Schools and Parks Pilots. The Schools Pilot officially launched on November 2, 2020. SCE and the DPR began coordinating to secure an MPA for the Parks Pilot in early 2021, and the MPA was signed in April 2022, marking the official Parks Pilot start date. SCE filed AL 4926-E on December 22, 2022, requesting the reallocation of funds for charging sites in DACs to include sites within five miles of DACs (i.e., DAC adjacent sites). On January 11, 2023, the Public Advocates Office (PAO) filed a protest requesting more information about the efforts SCE had made to prioritize DAC sites. SCE submitted a reply on January 19, 2023, detailing the work that the Parks Pilot team had completed to assess viability of each potential Parks Pilot site. The detail SCE provided was sufficient for the PAO, and AL 4926-E-A was officially approved on June 22, 2023. Although SCE did not submit a formal Advice Letter for final site selection, SCE and the DPR proceeded with nine park sites, which are expected to achieve the Pilot's port installation goal. In 2023, SCE secured the first eight site-specific addendum agreements, and in 2024, SCE secured the ninth and final site-specific addendum agreement. In 2025, SCE continued to work through the design, permitting, and pre-construction processes. In June 2025, the final Schools Pilot site was energized, and the school curriculum was closed out, marking the conclusion of the implementation phase.

Figure 115 shows major milestones since the beginning of the Schools and Parks Pilots.

Figure 115. SCE Schools and Parks Pilots Key Milestones



4.2.2. Findings

This section provides findings from analyses of the incremental EV adoptions, site visits and site costs, grid impacts, petroleum displacement, GHG and criteria pollutant reductions, and health impacts, as well as insight from Utility staff interviews.

Table 49 summarizes key impact parameters for EY2025 and for the program to date. Annual estimates of impacts are provided for metrics calculated as part of the impact evaluation. The table also provides estimates of impacts across all sites included in the program population through the end of 2025.

Table 49. SCE Schools Pilot Impacts Summary

Impact Parameter	EY2025 Sites [a]	EY2025 Sites Percentage in DAC	PTD Sites Actual	PTD Sites Actual Percentage in DAC
Population of Activated Sites	8	38%	30	53%
Sites included in analysis	8	38%	30	53%
Charging Ports Installed	78	46%	250	55%
Electric Energy Consumption (MWh)	93	38%	736	50%
Petroleum Displacement (gasoline gallon equivalent [GGE])	5,835	38%	58,076	50%
GHG Emission Reduction (MT) [b]	54.1	38%	476	50%
PM_{10} Reduction (kg)	0.28	38%	2.35	50%
$PM_{2.5}$ Reduction (kg)	0.26	38%	2.16	50%
ROG Reduction (kg)	2.90	38%	38.59	50%
CO Reduction (kg)	124.45	38%	1,331.95	50%

[a] Energy consumption, petroleum displacement, and emissions reductions are based on annualized data. Pilot-to-date results are based on actual data (see *Appendix B* for details).

[b] GHGs include CO_2, CH_4, and N_2O multiplied by their respective GWP as defined by IPCC AR5 (see *Appendix B* for details).

Incremental EV Adoption

There are two main channels through which the availability of public charging networks may affect EV purchases. The first is a network effect, through which EV owners gain increased access to the public charging stations because of the stations' placement at destinations such as workplaces, commercial establishments, schools, and parks. The Evaluation Team expects the availability of EV charging equipment at convenient locations (for midday charging away from home) to increase the convenience of owning an EV (such as by lessening range anxiety) and to increase the probability of EV ownership. The second channel is a neighborhood effect on the driving population living in areas neighboring the public EV charging stations. The Evaluation Team expects the availability of nearby charging infrastructure to reduce the cost of EV ownership by providing alternatives to home charging. We expect that public EV charging will have the biggest impact on residents of multifamily buildings, many of whom will have limited access to EV charging equipment, or on low-income households, which may be unable to afford home EV charging equipment. Public charging access may boost EV ownership through both channels, and there may be positive interactive effects between the channels that boost the overall impact of public charging networks. The Evaluation Team focused on analyzing the second channel and will analyze impacts for the first channel separately when data become available.

The Evaluation Team estimated the effect of the SCE Schools Pilot public charging stations on household EV adoption for neighboring populations with a two-stage analysis. In Stage 1, we looked at historical impacts of public EV charging on vehicle ownership. See *Appendix B* for details about the Stage 1 analysis. Using the impact estimates from the Stage 1 analysis, the Evaluation Team estimated the impact of SCE

investments in public charging on EV ownership for Stage 2.[68] By the end of EY2025, 30 charging sites in SCE's Schools Pilot had been activated. We estimated the impact of these stations based on annual EV registrations as well as cumulative EV registrations driven by the Schools Pilot through the end of 2025.

Based on the composite measure of public charging access, the Evaluation Team calculated the change in access to public charging due to SCE's Schools Pilot investment for each census block group (CBG) where the investments affected access. Table 50 shows that the average change in access across all affected CBGs from pilot sites through 2025 was approximately nine, and the average change in the number of chargers (ports) was nearly six per affected CBG. The average normalized EV annual registration per 1,000 households was just under 62 in the affected CBGs in the 2020 baseline year.

Table 50. SCE Schools Pilot Summary Statistics of Effects on 55 Affected CBGs

	Change in Composite Measure of Access [a]	Change in Number of Chargers	Normalized Annual EV Registrations [b]	Number of Households [c]
CBG Mean	8.57	5.96	61.42	474.40
Standard Deviation	(5.62)	(4.58)	(335.87)	(262.25)

These values are averages for the CBGs whose access to public charging was affected by SCE's investments.

[a] Change in composite measure of access and number of chargers is from 2020 to 2025.

[b] Normalized annual EV registrations are average annual values in the affected CBGs in 2020 per 1,000 households.

[c] Number of households is based on 2015–2019 ACS.

The Evaluation Team calculated the impact of the Utility's investments in public charging for the Schools Pilot on neighboring EV ownership. This involved combining the ordinary least squares (OLS) and instrumental variable two-stage least squares (IV-2SLS) regression estimates of the impact of public charging access on EV registrations from Stage 1 with the estimates of the CBG changes in public charging access and household counts.[69] The impacts of the SCE investments on EV registrations will depend on the extent to which the investments increased access to EV charging in the affected CBGs and the number of neighboring households in the CBGs.

Table 51 shows estimates of the annual and cumulative EV registrations attributable to the SCE Schools Pilot charging investments. Based on the OLS long differences model,[70] SCE Schools Pilot investments in charging facilities increased EY2025 annual EV registrations by 14 vehicles and cumulative EV registrations by 33 vehicles. Based on the IV-2SLS long differences model, the Schools Pilot investments increased

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[68] The Stage 1 analysis used vehicle registration data from 2015 to 2023, the most recent period with complete information at the CBG level. The EY2025 estimates assume that the impact of Utility-specific stations remains unchanged over time, which may not reflect actual market conditions and technological changes in 2025.

[69] In Stage 1, the Evaluation Team estimated the impact of public EV charging access on EV ownership. Stage 2 built on the Stage 1 analysis and was an attribution analysis for Utility-specific investments. A notable benefit of this approach is that it can be applied to evaluations of other programs that increase EV charging access, which allows methodological consistency.

[70] The long differences model estimates indicate the impact of public charging on EV registration over eight years. The Team annualized these estimates by dividing the results by eight.

annual EV registrations by 28 vehicles and cumulative registrations by 85 vehicles. The Evaluation Team prefers the IV-2SLS-based estimates because they account for the potential endogenous siting of public charging (i.e., siting public charging infrastructure in locations likely to have above- or below-average rates of EV adoption). These estimates reflect the 30 activated Schools Pilot facilities operating for a full year.

Table 51. SCE Schools Pilot Effects of Utility Investments on 2025 and Pilot-to-Date EV Registrations

	EY2025		Pilot to Date	
Analysis Model	OLS	IV-2SLS	OLS	IV-2SLS
Increase in EV Registrations	14.49	28.18	32.57	84.92
Standard Error	(0.81)	(2.63)	(1.28)	(4.96)

The Team estimated the OLS long differences using data for all CBGs in the analysis sample and estimated the IV-2SLS long differences for CBGs in the 20 largest California cities. The long differences are annualized eight-year estimates. For each affected CBG, the Team calculated the increase in annual registrations as the product of the regression-based access coefficient divided by eight, multiplied by the change in composite public charging access from utility investments (between baseline 2020 and EY2025), multiplied by the number of CBG households (in thousands). Robust standard errors clustered at the CBG level are in parentheses.

The SCE Schools Pilot investments in public charging show a modest but growing impact on EV ownership in EY2025. Across all 55 affected CBGs, the total annual number of EV registrations was about 3,378 (55 * 61.42) in baseline year 2020, so the preferred IV-2SLS regression method estimates that the cumulative impact of the SCE Schools Pilot through 2025 was an increase in EV registrations of about 2.5% (84.92/3,378) from 1.8% in EY2024. This increase of 0.7 percentage point, or 39% year-over-year gain, suggests that the pilot's effects continue to strengthen over time. An average of 61 EV registrations per CBG puts these CBGs in the 92nd percentile for EV registration among CBGs, implying a high level of baseline EV registration, which explains the small percentage effects. The Evaluation Team attributes the pilot's impact on EV ownership primarily to the growth in charging stations and the increased number of influenced CBGs.

Highlights

- The IV-2SLS model's output shows that the SCE Schools Pilot may have contributed to the adoption of 85 EVs in the program to date for households neighboring the infrastructure.
- The SCE Schools Pilot showed meaningful yearly growth in EV registrations, with a 39% increase from EY2024 to EY2025 (rising from 1.8% to 2.5%), indicating strengthening program effects.

Site Visit Findings

The Evaluation Team visited eight newly completed sites in EY2025. During the site visits, the Team documented 78 installed L2 charging ports with a total capacity of 550 kW and between six and 12 charging ports installed per site. Each installed port had a dedicated space marked for EV charging, including spaces which were designated for ADA. Some sites also had up to three adjacent unmarked

spaces in reach of charging cords, enabling drivers to charge if the dedicated EV charging space was occupied but the charger was not being used to charge a vehicle.

Figure 116 and Table 52 show total installed ports and installed capacity for EY2025 and pilot-to-date sites. All of these sites have L2 charging with 30 amp continuous power (~7 kW), with the exception of sites in one district that opted to own the BTM infrastructure at two of their sites and installed slightly higher-powered (40 amp continuous) charging stations

Figure 116. SCE Schools Pilot L2 Ports and Capacity Observed in 2025 and in the Pilot to Date

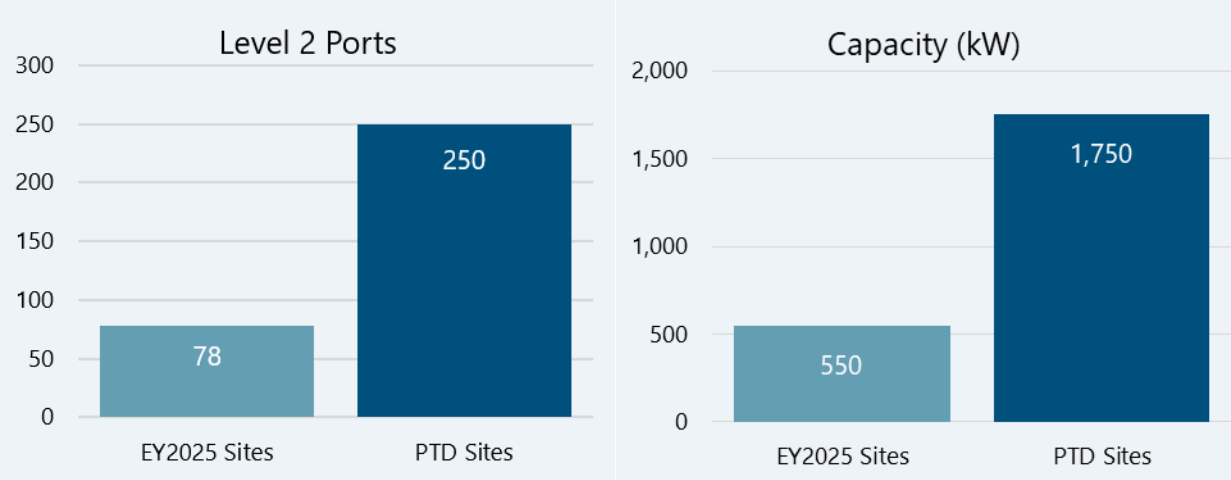
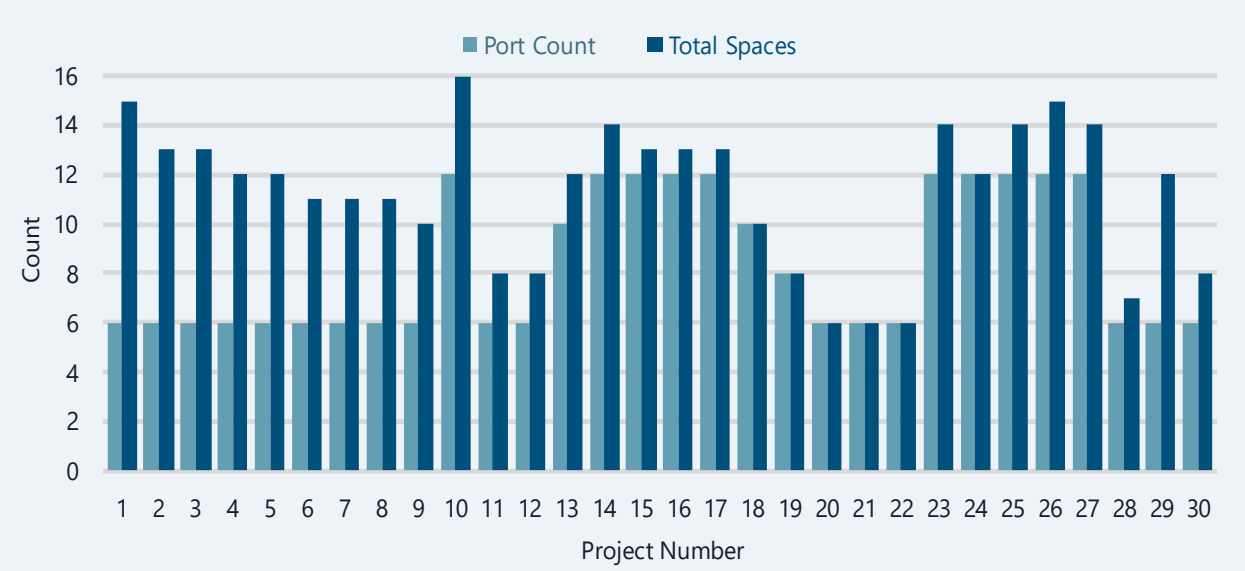


Table 52. SCE Schools Pilot Ports and Capacity Observed during Site Visits

Site Visit	Ports	Installed Capacity	Number of Sites
EY2025 Sites	78	550	8
PTD Sites	250	1,750	30

EY2025 sites were similar to those visited in past evaluation years in terms of EVSE and site design. On average, in EY2025 each charging port was accessible to 2.5 parking spaces. However, SCE Schools Pilot PTD sites show an average of 1.3 parking spaces within reach of a charging port. Figure 117 shows the number of ports and the number of parking spaces that can access ports based on site visits to PTD sites. The top 10 sites average 1.7 ports. The higher the ratio of parking spaces to ports, the more vehicles can access a charging port without moving the first vehicle, which can improve overall charger utilization. Higher access can therefore help meet increased driver demand.

Figure 117. SCE Schools Pilot Visited Sites Charging Port Availability by Site for PTD Sites



The Evaluation Team reviewed the pricing structure available to EV drivers. SCE uses TOU-EV-oriented billing rates, some of which (TOU-EV 7) began phasing in a 16.6% increase in demand-oriented costs in 2024 which may have affected the retail pricing decisions of some site operators in 2025. In theory operators of these sites might want to influence when charging takes place to maximize charging when energy is the least expensive and to minimize those demand-oriented costs.

In analyzing customer pricing across all sites visited in the pilot to date, the Evaluation Team made several key observations.

- The Evaluation Team was unable to confirm pricing at six of 30 sites at the time of the site visit or via subsequent research at Plugshare.com or other NSP websites.
- Eleven of 30 sites provide TOU pricing to EV drivers.
  - Costs increase from periods of low energy use to peak periods by 125% to 330%
  - Energy costs range from $0.12/kWh during off-peak periods to $0.85/kWh for on-peak periods.
- Thirteen sites provide flat rates to EV drivers.
  - Energy costs range from $0.30/kWh to $0.55/kWh
  - Eleven total sites use idle fees to influence EV drivers to turn over the charging station once they have finished charging their vehicle.
  - Idle fees range from $3 to $20 per hour
- Grace periods, once charging was complete, ranged from 15 minutes to four hours.

Highlights

- One school district opted to own its chargers and selected slightly higher-powered L2 equipment.
- Ten sites have at least two parking spaces within reach of each charging cord on average, while only five sites have one-to-one access.
- Eleven sites provide TOU rates that may help influence when drivers charge.
- Eleven sites use idle fees to encourage turnover and therefore improve access to charging ports.
- Some sites had greater public access, increasing utilization and overall benefits through overnight and weekend charging, while other sites made charging available only to staff during common business hours Monday through Friday between 8 a.m. and 5 p.m.

Site Costs

The Evaluation Team conducted an analysis of the 21 school sites activated from EY2021 through EY2025 with fully closed out finances as of December 31, 2025. The set of fully closed out sites is smaller than the set of activated sites because of the time involved in performing activities such as collecting receipts, paying invoices, and obtaining administrative approvals. Cost estimates are presented in nominal dollars. The 21 sites all had L2 ports, with an average of 53.7 kW of installed capacity and 7.9 ports per site.

Figure 118 shows the distribution of site-level costs for the 21 sites. The horizontal lines of the boxes show the 25th, 50th, and 75th percentile of sites; the X denotes the mean site cost; and the three panels are defined as follows:

- **Utility Infrastructure Costs.** Site costs borne by the Utility for TTM and BTM.[71]
- **Ratepayer-Funded Costs.** All site costs paid for by the Utility, including TTM, BTM and EVSE rebate.
- **Estimated All-In Costs.** The total estimated cost of installing the site, including capital and labor costs for the Utility and the customer. The value is calculated by summing 100% of TTM,[72] BTM, and EVSE costs.

[71] Utility infrastructure costs are the same as the ratepayer-funded costs, except the Utility infrastructure costs do not include EVSE rebates.

[72] The Utility pays 100% of the TTM costs and therefore reports actual TTM costs to the Evaluation Team.

Figure 118. SCE Schools Pilot Per-Site Costs Organized by Three Perspectives, Across 21 Closed-out PTD Sites

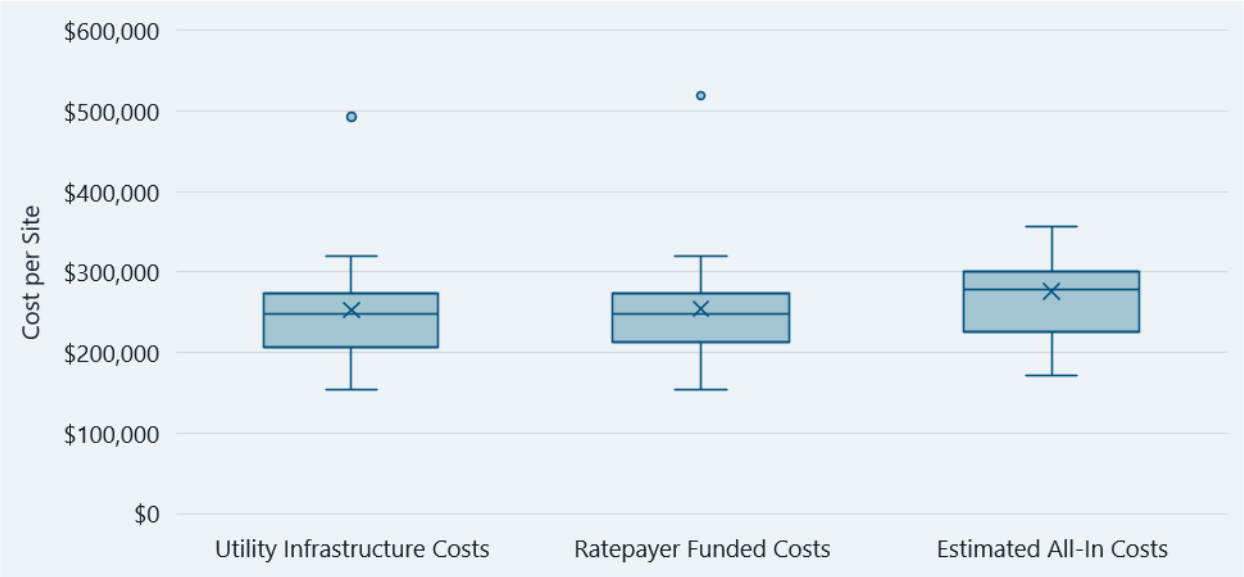
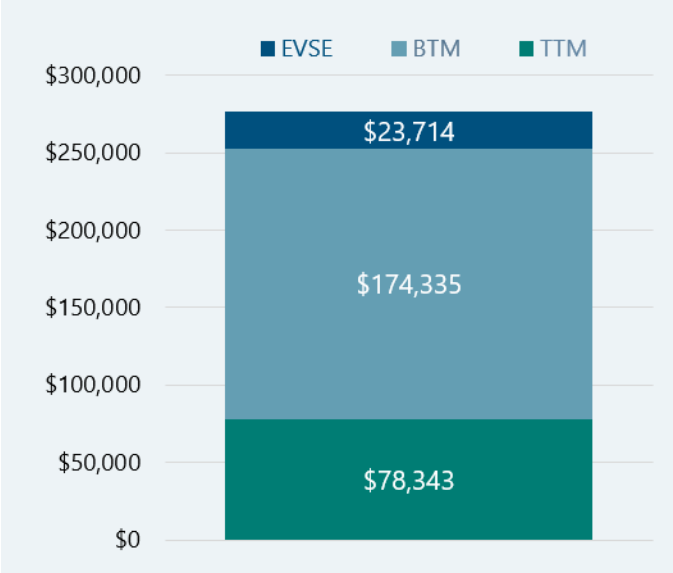


Figure 119 shows average estimated all-in costs for the 21 PTD sites. BTM is the largest cost across the sites, followed by TTM, then EVSE. Together, the average all-in TTM, BTM, and EVSE cost is $276,392 through 2025.[73]

Figure 119. SCE Schools Pilot Average All-In Costs, Across 21 Closed-out PTD Sites



[73] Calculated by summing all TTM, BTM, and EVSE costs borne by SCE and the customer and dividing by 21 sites.

Figure 120 shows the distribution of Utility infrastructure costs (corresponding to the far-left panel in Figure 118) per site and per kilowatt. The average Utility infrastructure cost, including TTM and BTM borne by SCE through 2025 was $252,678 per site and $4,960 per kilowatt of installed charging capacity.

Figure 120. SCE Schools Pilot Cost per Site and per Kilowatt Across 21 Closed-out PTD Sites



Highlights

- Estimated all-in costs paid by the customer and SCE vary widely between sites, with an average of $276,392 per site. On average, BTM was the largest cost across the sites, followed by costs for TTM and EVSE.
- The average utility infrastructure cost in the pilot to date, including TTM and BTM borne by SCE, was $252,678 per site, and $4,960 per kilowatt.

Grid Impacts

The Evaluation Team determined grid impacts for the SCE Schools Pilot based on our analysis of energy consumed by operational charging stations installed through the program through the end of 2025, combined with charging session data from NSPs.

Data Sources

The primary data source used in this section is energy usage data provided in regular 15-minute intervals from the AMI. Other data sources include customer bills and charging session–specific data provided by NSPs. There are several important differences between AMI and NSP data. While AMI data reflect only energy usage, NSP data include energy usage, session start and stop time, the duration of a vehicle's connection to a charging port, the duration of a vehicle actively pulling power, and the specific port used for a session. An AMI meter does, however, track standing loads (such as those the EVSE uses for communications, cooling, active power converters, solenoids, and screens), which NSPs typically cannot do. When AMI data are missing from the dataset, the Evaluation Team uses NSP data to fill the gaps.

Summary of Grid Impacts

Table 53 presents a summary of the estimated Schools Pilot program grid impacts.

Table 53. SCE Schools Pilot Grid Impacts

Impact Parameter	Actual 2025 [a]	Actual PTD	10-Year Projection PTD
Operational Sites	8	30	30
Installed Capacity (kW)	550	1,750	1,750
Electric Energy Consumption, MWh	358	736	3,560
On-Peak (4 p.m. to 9 p.m.) MWh (and % of total)	42.9 (12.0%)	89.6 (12.2%)	N/A
Maximum Demand, kW (with date and time)	322 (12/8/25 9:30 a.m.)	322 (12/8/25 9:30 a.m.)	N/A
Maximum On-Peak Demand, kW (with date and time)	105 (11/18/26 4:30 p.m.)	105 (11/18/26 4:30 p.m.)	N/A

[a] Energy consumption, peak consumption, and demand data are based on PTD activated sites for calendar year 2025.

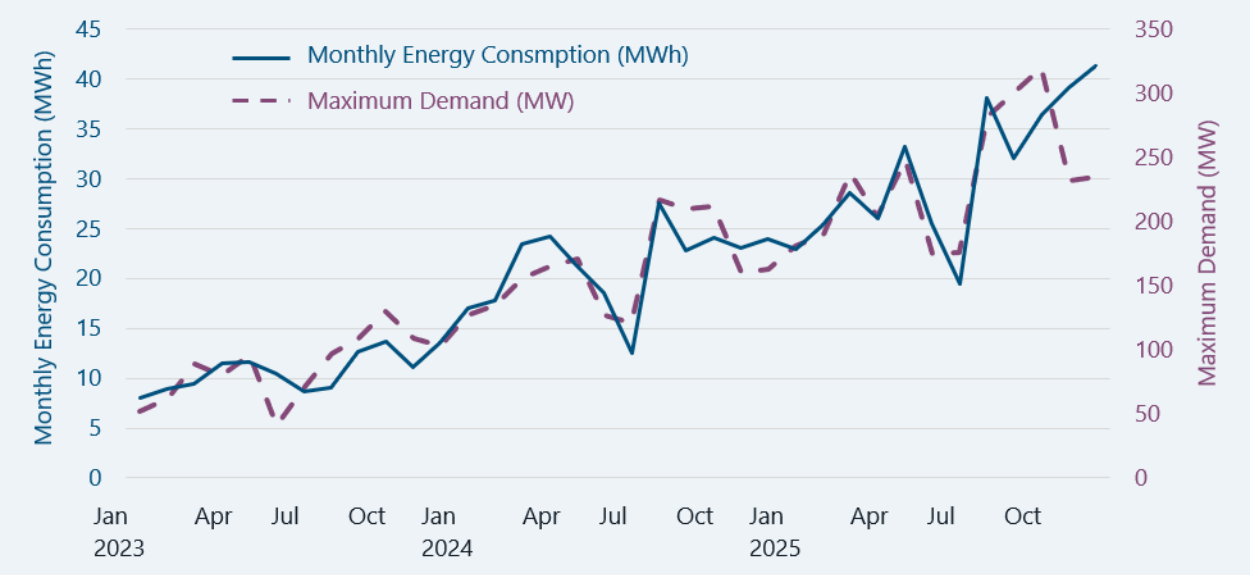
The remainder of this section offers detailed findings on actual consumption, demand, and charging session–oriented trends of the combined sites through calendar year 2025.

Energy Trends

Eight pilot sites were activated in 2025, bringing the total number of activated sites through the end of 2025 to 30. Sites in the Schools Pilot reached total consumption of 358 MWh in EY2025, up from 252 MWh in EY2025. This brings total consumption to 728 MWh for all sites in the program to date.

Figure 121 plots monthly energy consumption and maximum demand values for pilot-to-date sites in the Schools Pilot. The figure shows a general upward trend with significant drops in demand during the summer months coinciding with the school year. Demand peaked at 322 kW in aggregate across all sites at 9:30 a.m. on December 8, 2025, compared with 1.75 MW of installed capacity. Similar to trends observed in prior evaluation years, capacity continues to be several times more than demand.

Figure 121. SCE Schools Pilot Monthly Energy Consumption and Maximum Demand for PTD Sites



As presented in Figure 122, total daily energy consumption continues to increase across program sites, with daily consumption reaching 2 MWh several times in the second half of EY2025, and maximum demand consistently spiking above 225 kW in the fourth quarter of EY2025, with a peak of 322 kW.

Figure 122. SCE Schools Pilot Daily Energy Consumption and Maximum Demand, Pilot-to-Date Sites

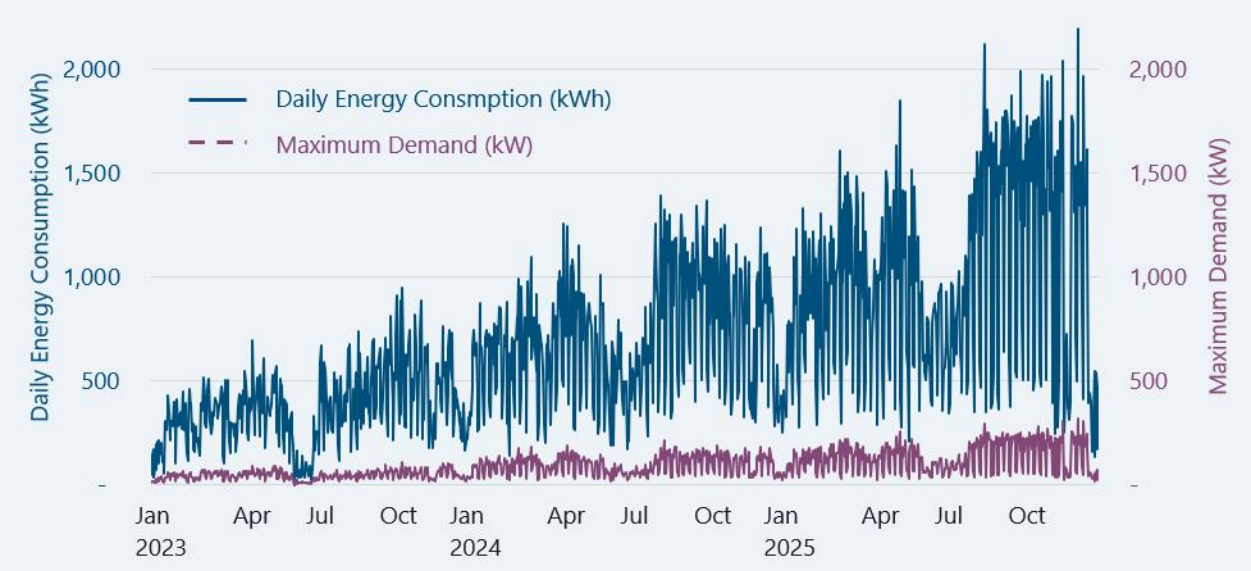


Figure 123 shows average load curves of weekdays and weekends in the fourth quarter of EY2025. These load curves are similar to depictions of typical workplace charging behavior seen outside of the SCE portfolio. Charging load ramps up between 6 a.m. and 9 a.m. as drivers arrive, peaks between 9 a.m. and

11 a.m. as all connected vehicles are charging, and tapers off over the rest of the day as individual vehicles complete their charge.

Figure 123. SCE Schools Pilot Average Weekday and Weekend Q4 2025 Load Curves

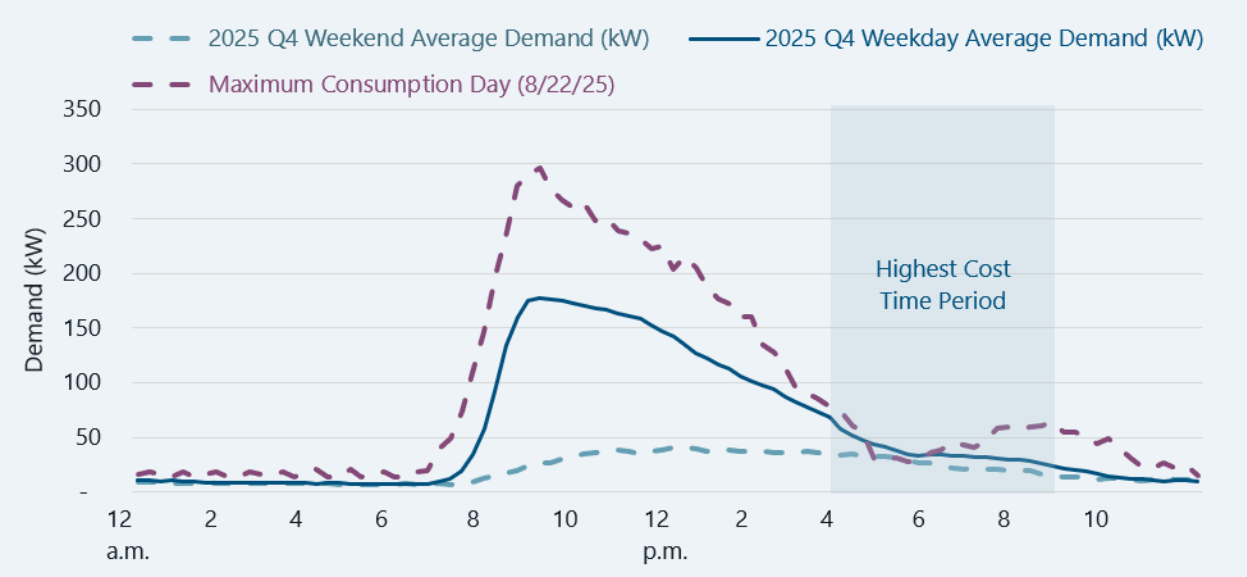
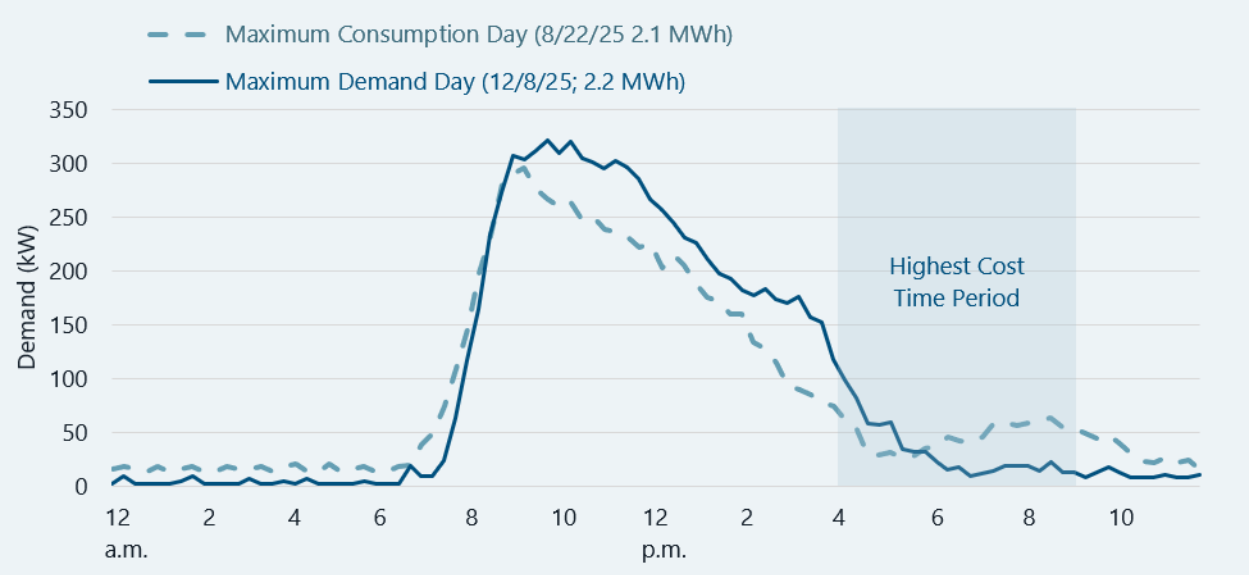


Figure 124 presents examples of daily load curves for two weekdays that had the highest maximum demand and highest daily consumption in EY2025 for all sites in the pilot-to-date. Both days show notable charging demand of around 300 kW during the morning hours, with some charging demand remaining in the evening and late-night hours. Charging sessions continuing outside of typical school hours, particularly, overnight, indicate that some of the sites are supporting the local community and not just faculty and staff at the schools. Use by community members outside of the school community increases overall utilization at these sites, which benefits Utility ratepayers.

The finding that use of the Schools Pilot sites extends past the school community may encourage schools to design similar sites in the future with a policy that increases charger utilization by allowing public access to charging infrastructure. Residents in multifamily dwellings who live close to schools may especially benefit from access to these charging sites. However, most of the sites in the Schools Pilot sites are considered private and, as such, are not always shown on native NSP websites or Plugshare.com.

Figure 124. SCE Schools Pilot Load Curves on Days of Maximum Demand and Consumption



The impact of pricing on how and to what extent EV drivers use energy remains inconclusive for sites in the Schools Pilot because most of these sites are still ramping up and have low overall utilization. SCE reports that all Schools Pilot sites have adopted the Utility's EV-specific tariffs, which use TOU rates for the customer of record (i.e., school districts or their NSP or similar partners that operate the EVSE). However, the site hosts/NSP select the pricing provided to EV drivers who use the charging facilities; the *Site Visits* section identifies retail pricing for the majority of sites, which is a mix of TOU and flat rate.

Usage Trends

With 22 of the sites in the Schools Pilot having reached operational maturity (having been operational for between one and four years), the Evaluation Team was able to analyze site performance over time. This section assesses program characteristics by comparing energy consumption, load factor (a measure of consistency of usage) and total charging sessions across sites. This analysis begins with a site's initial charging sessions, rather than when AMI data are first available, to eliminate early periods when chargers are powered up but not necessarily commissioned by their NSPs (i.e., in a testing period) or are not available for public use. Month zero is defined as the month when public access began.

Figure 125 and Figure 126 aggregate monthly energy consumption trends for active sites, grouping sites by whether they have achieved a 12% load factor to improve data visualization.

As shown, sites with a higher load factor more frequently dispense over 1.5 MWh monthly, while sites with a lower load factor typically dispense 1 MWh or less. Only one site below a 12% load factor showed multiple months in which it dispensed 2 MWh of energy.

Figure 125. SCE Schools Pilot Monthly Energy Consumption (>12% Load Factor)



Figure 126. SCE Schools Pilot Monthly Energy Consumption (<12% Load Factor)

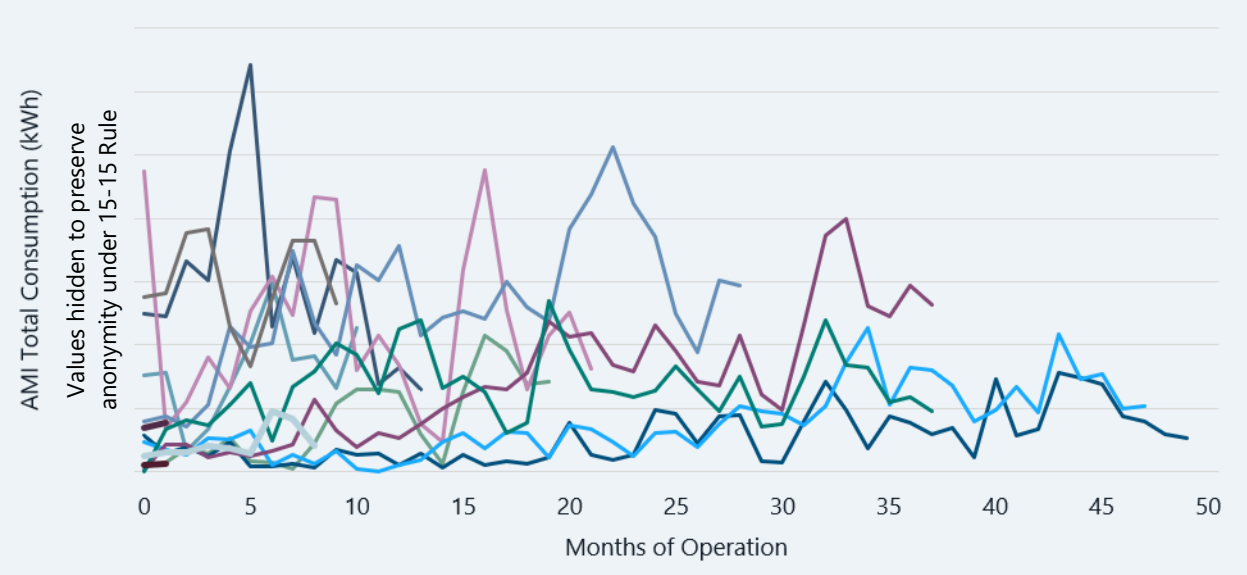


Figure 127 and Figure 128 show the monthly load factor of Schools Pilot sites. Load factors compare a site's actual monthly energy consumption to what it would have been if it had achieved the 15-minute interval of maximum demand for the entire month. A constant demand, for example, would result in a 100% load factor (which is considered impossible). This is not necessarily a marker of how much capacity is being utilized (demand vs. installed capacity).

Figure 127 and Figure 128 show that half the sites with data in the Schools Pilot have a maximum monthly load factor of typically <12%. Some months with particularly low levels of charging occur in the summer or include school breaks when charging is less likely to occur. Overall, the load factor suggests that maximum demand is very inconsistent at most sites, reflecting low utilization or slow uptake by EV drivers at these sites.

Figure 127. SCE Schools Pilot Monthly Load Factor (<12%)

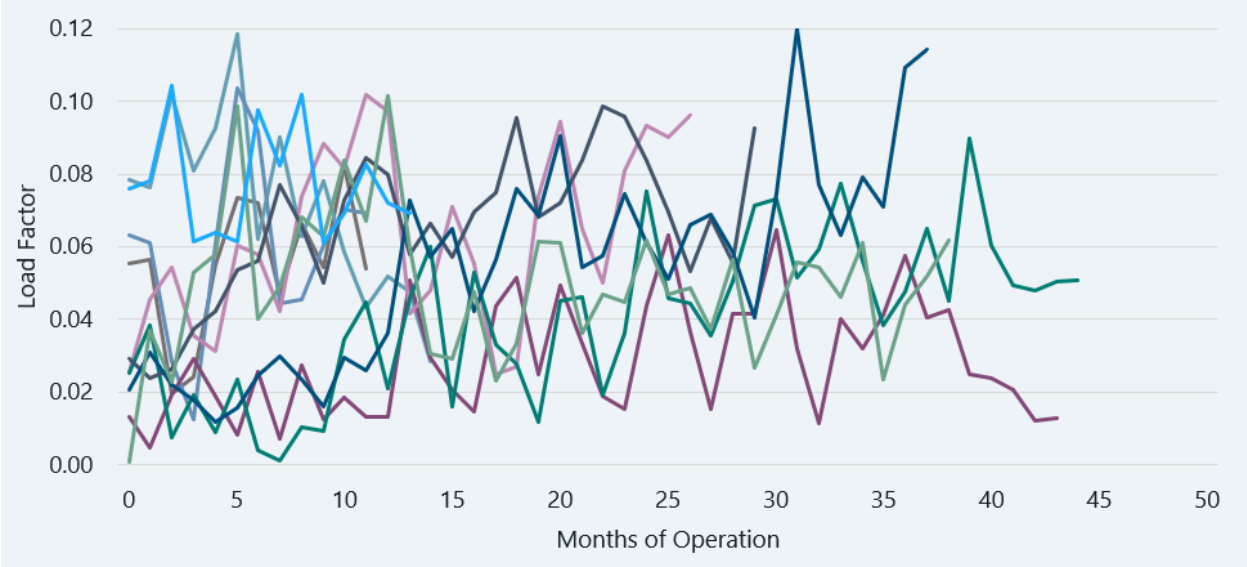
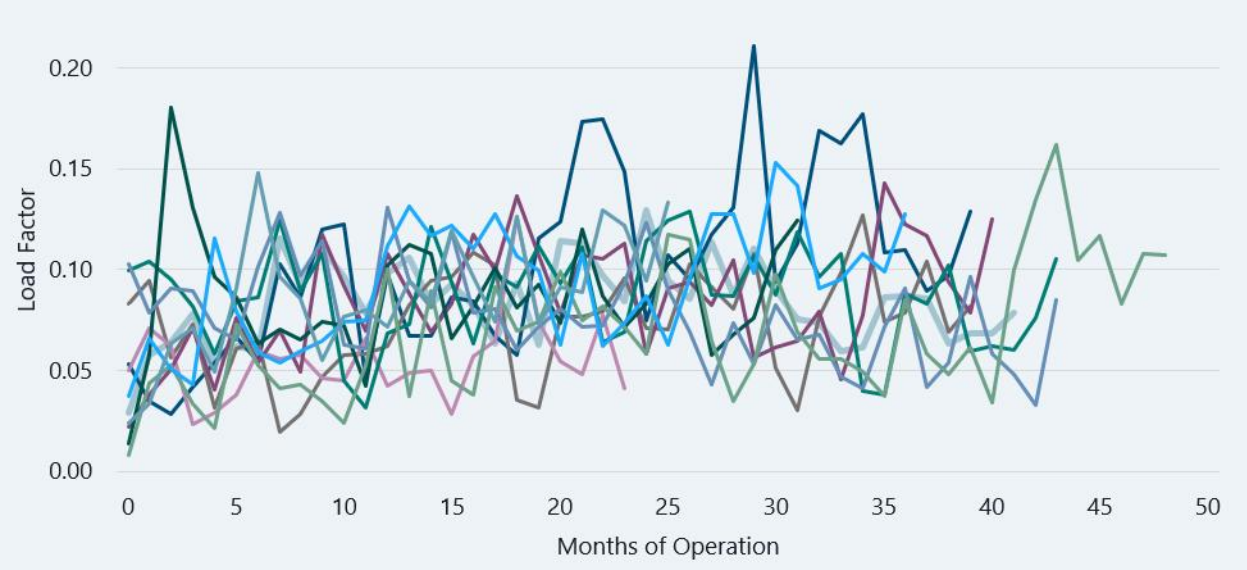


Figure 128. SCE Schools Pilot Monthly Load Factor (>12%)



High-Utilization Sites

Utilization for several sites suggests that these are high-utilization sites. These sites have three distinct charging periods: Monday through Friday business hours, overnight, and weekend charging and appear to function as public EV charging resources, rather than private sites that serve only school staff and visitors during common business hours. Low utilization sites have limited or no charging during weekends or overnights shown below with 90% less demand. The Baseline Weekday series in Figure 129 includes all active sites of the program showing a distinct short duration increase in load on weekday mornings that tapers off steadily during business hours. Minimal overnight load is similar on weekdays and weekends. The chart also shows utilization for sites that have average demand of up to four times that of typical weekends hours. Based on Utility bill costs per kilowatt-hour (shown in the *Charge Ready Transport Grid Impacts* section), increased utilization typically causes average billed cost per kilowatt-hour to decrease. Increased utilization also increases the use of renewable energy, especially over weekends.

Figure 129. SCE Schools Pilot High-Utilization Sites Average Power per Port

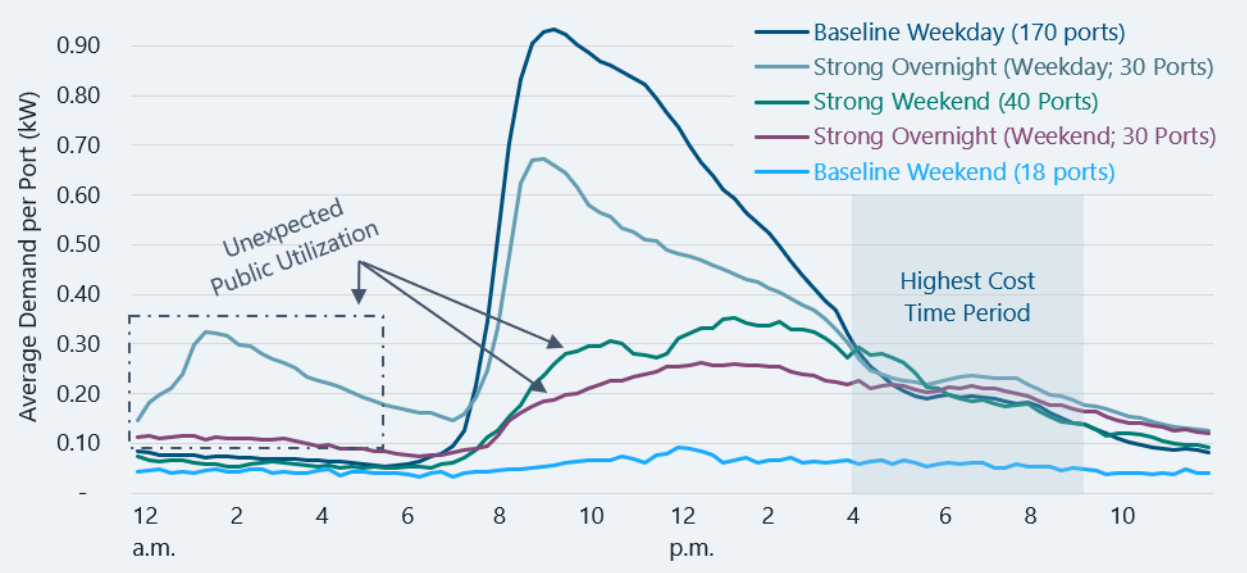


Figure 130 presents the total number of charging sessions in the Schools Pilot. Over 40,000 charging sessions have occurred in the pilot to date, with approximately one-third of these sessions occurring in EY2025. Because these sites are within school districts, utilization dips noticeably during the summer and winter break periods. Similar to charging behavior in EY2024, utilization in EY2025 showed a maximum daily rate of 60 to 70 sessions per day despite an additional 40 ports were installed in EY2025. Similar to charging behavior in EY2024, utilization in EY2025 showed a maximum daily rate of 60 to 70 sessions per day despite an additional 40 ports installed in EY2025. That the number of charging sessions remained flat highlights lower overall utilization in EY2025 than in EY2024.

Figure 130. SCE Schools Pilot Daily Charging Sessions for PTD Sites

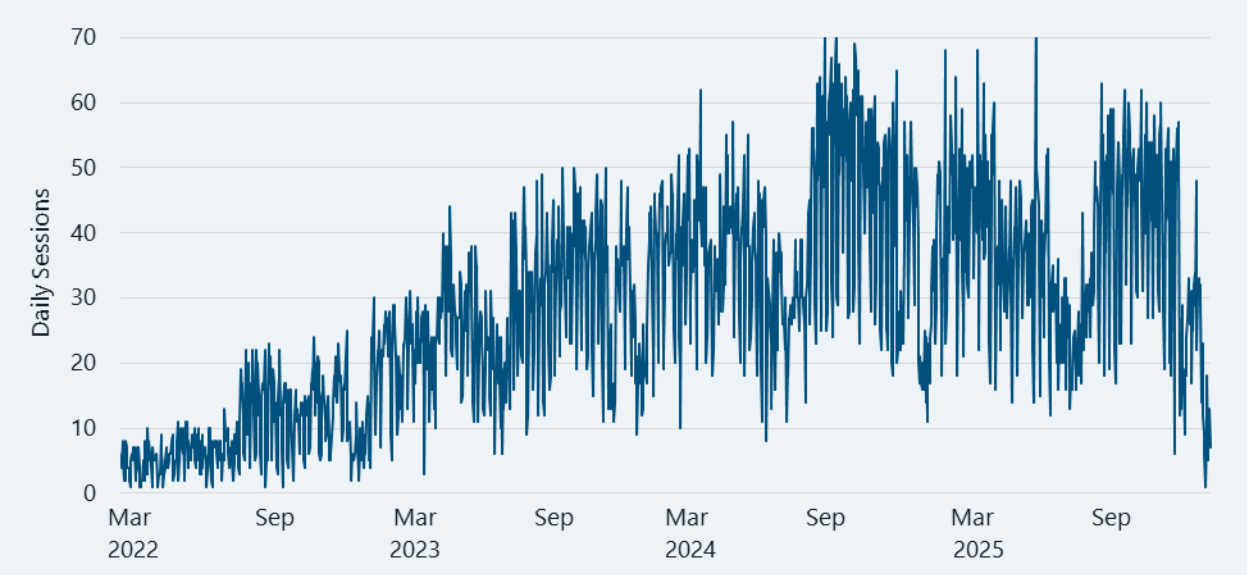
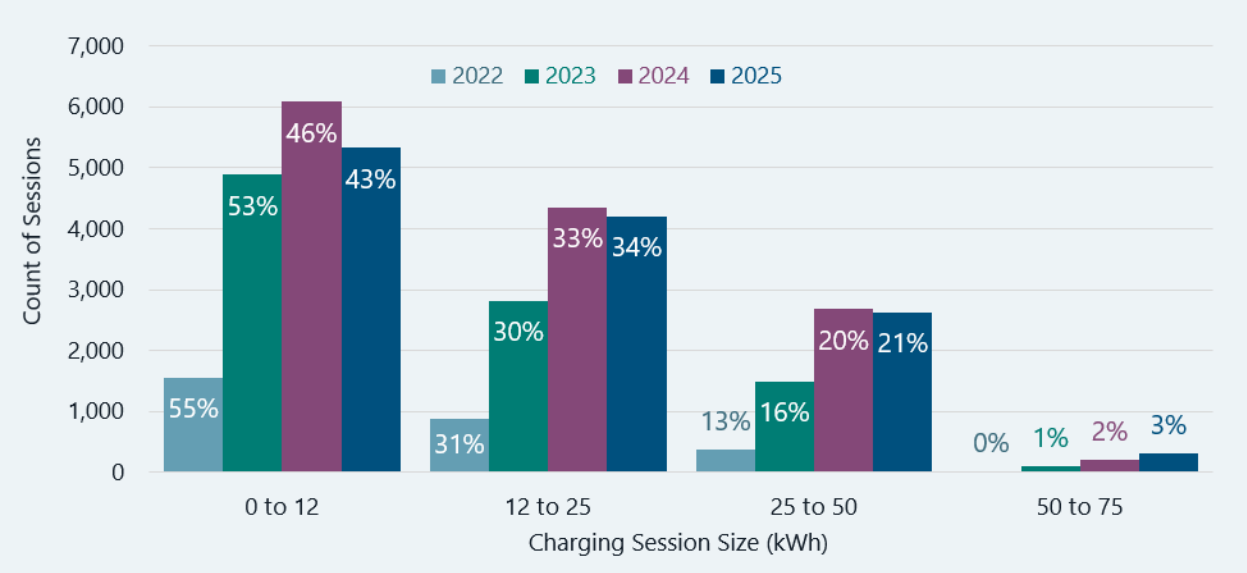


Figure 131 presents the distribution of charging sessions by consumption (kilowatt-hours) for all sites in the Schools Pilot to date. Erratic charging sessions (below 1 kWh or less than 0.1 hours) were not included. As shown, charging sessions that were less than 12 kWh dropped from 46% to 43% in EY2025. Charging sessions over 50 kWh increased slightly from 2% in EY2024 to 3% in EY2025. Large sessions (over 25 kWh) increased from 22% to 24%.

Figure 131. SCE Schools Pilot Charging Session Count by Consumption Size for PTD Sites



Through EY2025 several thousand unique and anonymous drivers were recorded using Schools Pilot charging sites. As seen in the middle chart of Figure 132, just over 85% of these drivers were new or infrequent users, with five or fewer total sessions during the lifetime of the pilot. However, nearly 15% of

drivers may be considered to be frequent users with over five sessions. Nearly 5% of drivers are very frequent users, with at least 25 charging sessions. 50 EV drivers have over a hundred charging sessions.

The leftmost chart of Figure 132 shows that one sixth (17%) of drivers have charging sessions of at least 25 kWh, while one-third of drivers (33%) have charged between 10 kWh and 25 kWh; the average charging session was 16 kWh. Another way to review this population is by how much energy these drivers have consumed, which is shown on the right site of Figure 132. Nearly 95% of EV drivers have purchased 250 kWh or less. At least 100 EV drivers have consumed more than 1 MWh, with 10 drivers consuming over 5 MWh. These numbers indicate that the sites drivers use are reliable, which may lead to cost-effectiveness.

Figure 132. SCE Schools Pilot EV Driver Statistics



Represents 100% of drivers | Represents 14% of drivers | Represents 6% of drivers

Highlights

- Sites in the Schools Pilot showed total consumption of over 358 MWh in 2025, leading to a pilot-to-date total of 736 MWh.
- Eight sites were activated in 2025, for 30 total activated sites through the end of 2025.
- Year-end installed capacity was approximately 1,750 kW with actual portfolio demand reaching 322 kW.
- Several sites show relatively higher utilization through a significant portion of energy consumption during non-business hours (overnight and or weekend) likely attributable to local residents who do not have EV chargers at home.
- Schools Pilot sites with higher load factors were more likely to achieve over 2 MWh of monthly consumption in EY2025. Sites with the highest load factors had overnight and weekend access to charging in addition to access during regular workplace hours.
- Sites with lower load factors are seeing 500 kWh to 1,000 kWh of energy consumption monthly with less workplace charging and limited public access.

Petroleum Displacement

The Evaluation Team estimated Pilot-induced petroleum displacement related to the 30 operational SCE Schools Pilot sites using three key pieces of information: electricity used for vehicle charging, EV annual miles traveled, and annual counterfactual vehicle fuel consumption. From this information, we estimated the reduction in equivalent gallons of petroleum as a result of the SCE Schools Pilot. Table 54 presents petroleum displacement impacts for the Schools Pilot sites through 2025, including estimated actual impacts for 2025, actual impacts for all pilot-to-date sites, and a 10-year forecast for pilot-to-date sites.

Table 54. SCE Schools Pilot Petroleum Displacement Summary, PTD Sites

DAC Status	Usage (n=30)				Petroleum Displacement (GGE)		
	2025 Actual [a] (kWh)	PTD Actual [b] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
Inside DAC	202,226	371,070	598,016	1,101,011	15,469	29,004	130,604
Outside DAC	155,341	365,378	457,818	1,083,597	11,901	29,071	104,816
Total	357,567	736,448	1,055,834	2,184,608	27,370	58,076	235,420

[a] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.

[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Highlights

- The 30 Schools Pilot sites in the pilot to date collectively achieved an impact by the end of 2025 of over 58,000 gallons of petroleum displaced, with 50% displaced within DACs.
- Over a 10-year period, these sites will displace more than 235,000 gallons of petroleum.

Greenhouse Gas and Criteria Pollutant Impact

The Evaluation Team calculated emissions reductions from displaced fossil fuel use from ICE vehicles that were not in service as a result of the SCE Schools Pilot. The Team first developed one ICE counterfactual, then calculated the emissions associated with this vehicle under conditions that otherwise matched the EVs to provide a baseline. Although EVs have no tailpipe emissions, the mix of generation sources from the electric grid used includes renewable as well as fossil fuel power to supply electricity to the charging stations, with the latter primarily responsible for emitting GHGs and criteria pollutants into the atmosphere.

Table 55 presents the GHG reduction resulting from the 30 activated Schools Pilot in 2025, along with the pilot-to-date and 10-year totals, by impact location. Overall, the Schools Pilot sites achieved a reduction of 84% of GHG emissions (476 MT total) relative to the counterfactual to date (565 MT, not shown in the table), with 50% of the impact within DACs.

Table 55. SCE Schools Pilot GHG Reductions Summary, PTD Sites [a]

DAC Status	Usage (n=30)				GHG Reduction (MT)		
	2025 Actual [b] (kWh)	PTD Actual [c] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
Inside DAC	202,226	371,070	598,016	1,101,011	132	240	1,182
Outside DAC	155,341	365,378	457,818	1,083,597	102	235	957
Total	357,567	736,448	1,055,834	2,184,608	234	476	2,140

[a] Columns may not sum to total due to rounding.
[b] "2025 Actual" represents the data from all activated sites from pilot inception for the calendar year 2025.
[c] "PTD Actual" represents the data from all activated sites from pilot inception for all program years.

Looking at local emissions, the Schools Pilot had the highest impact in reducing CO, resulting in an estimated PTD reduction of 1,332 kg for the pilot to date and a projected 10-year reduction of more than 6,700 kg (Table 56).

Table 56. SCE Schools Pilot Local Emissions Net Reductions

Emissions	EY2025 Sites Annualized (n=8)			PTD Sites (n=30)	
	Inside DAC	Outside DAC	Total [a]	Actual	10-Year Projection
PM_{10} (kg)	0.11	0.18	0.28	2.35	10.08
$PM_{2.5}$ (kg)	0.10	0.16	0.26	2.16	9.26
ROG (kg)	1.10	1.80	2.90	38.59	195.13
CO (kg)	47.05	77.40	124.45	1,331.95	6,798.45

Figure 133 shows the mix of electricity from the CAISO grid used to support the SCE Schools Pilot sites.[74] Based on the real-time grid conditions when the EVs charged, the overall energy mix contained about 65% zero-emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass,

[74] The power associated with imports comes from a mixture of hydro, nuclear, and natural gas plants located outside the CAISO grid.

and nuclear) and 25% natural gas. With the CAISO grid adding more renewables to meet the Renewable Portfolio Standard, GHG and criteria pollutant emissions will continue to decrease.

Figure 133. SCE Schools Pilot Net Electricity Mix, Pilot-to-Date Sites

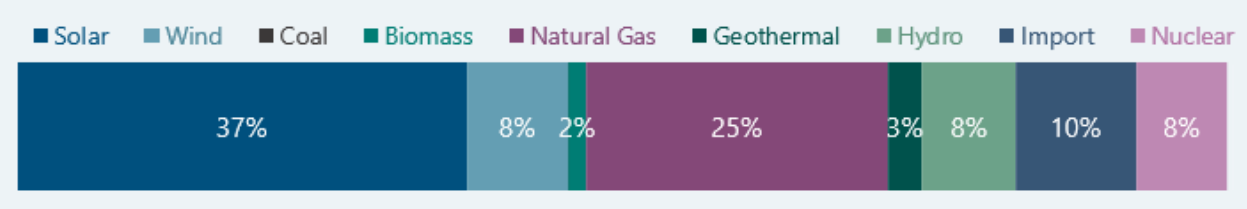
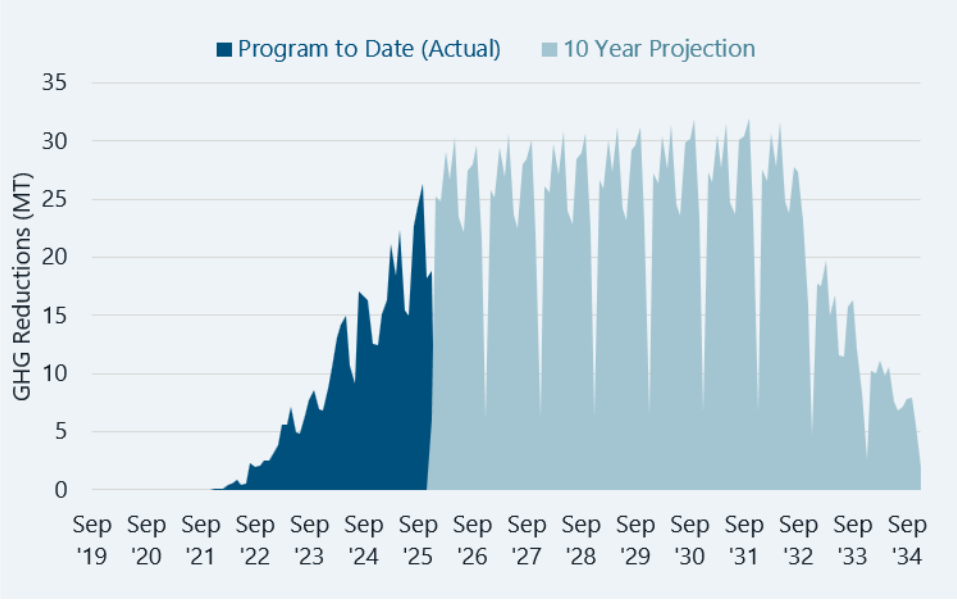


Figure 134 shows how GHG reductions from the Schools Pilot have increased to date and how these reductions are expected to grow over time for all activated sites. The analysis period ranges from the date of activation for the first site in the pilot through the end of 2025. The analysis incorporates the net reduction (counterfactual emissions minus Utility emissions) for each site within the SCE Charge Ready Schools Pilot. Emissions reductions from the pilot to date are shown in dark blue, while anticipated benefits based on annualization appear in a lighter blue. Because sites begin operations at different times, the 10-year sunset for each appears as a gradual tapering of Schools Pilot benefits after 2032. This taper reflects that benefits are no longer counted after 10 years, although Schools will likely continue to use the infrastructure. While each year's operations appear similar, there are several key factors driving the slight variations such as seasonality of Utility generation sources (high Utility emissions will appear as a dip on the curves), holidays occurring on weekends versus weekdays, and extrapolation for sites that became operational late in 2025 and will operate year-round in future years.

Figure 134. SCE Schools Pilot Historical and Forecasted GHG Reductions, Pilot-to-Date Sites



Highlights

- In 2025, the Charge Ready Schools Pilot achieved an 84% reduction of GHG to date with 50.4% of its impact occurring within DACs.
- The greatest reduction in local emissions in 2025 was for CO, with a projected 10-year period reduction of more than 6,700 kg.
- Based on the real-time grid conditions when EV charging occurred, the overall energy mix contained about 65% zero-emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 25% natural gas.

Health Impacts

The Evaluation Team calculated public health impacts (as benefits and costs) of reductions in criteria pollutants from vehicle electrification. Pollutants included in the analysis are primary $PM_{2.5}$ and precursors of secondary $PM_{2.5}$, including NO_X, SO_2, NH_3, and VOCs. This analysis considered only tailpipe emissions reductions rather than full lifecycle emissions (such as power plant emissions). The Evaluation Team used the EPA's COBRA tool to evaluate the health benefits associated with emissions reductions. COBRA estimates the county-level benefits for the county in which emissions are reduced. The tool also estimates the monetized benefits for all counties in the United States (since emissions disperse beyond the county of the source), although most impacts are felt within nearby counties and our analysis examines only California counties.

The morbidity-related monetary benefits the Evaluation Team estimated include avoided lost wages, avoided medical costs, and the money people are willing to pay to avoid an illness or condition like a respiratory disease. The Team measured these benefits in terms of the value of a statistical life associated with premature mortality. COBRA reports both a low and high impact for mortality, representing the uncertainties in the estimates.

The total value of the health benefits associated with emissions reductions from the Charge Ready Schools program for activated PTD sites is between $6,373 and $9,003. Table 57 shows the cumulative health benefits in California broken down by the electrification of SCE Charge Ready School sites for the program to date by health endpoint.

Table 57. SCE Schools Pilot California Health Benefits for PTD Sites in 2025

Health Endpoint	Change in Incidence (Annual Cases)		Monetary Value (Annual, 2025 Dollars)	
	Low	High	Low	High
Mortality	**< 0.000**	**< 0.000**	**$5,595**	**$8,225**
Avoided Medical Care				
Hospitalization, Respiratory	< 0.000	< 0.000	$0	$0
Hospitalization, Cardiovascular	< 0.000	< 0.000	$0	$0
Hospitalization, Other	< 0.000	< 0.000	$2	$2
ER Visits, Respiratory	< 0.000	< 0.000	$2	$2
ER Visits, Cardiovascular	< 0.000	< 0.000	$0	$0
Out of Hospital Heart Attacks	< 0.000	< 0.000	$0	$0
Nonfatal Heart Attacks	< 0.000	< 0.000	$10	$10
Stroke	< 0.000	< 0.000	$0	$0
Lung Cancer	< 0.000	< 0.000	$0	$0
Asthma	0.435	0.435	$351	$351
Hay Fever	0.018	0.018	$20	$20
Lost Productivity				
Minor Restricted Activity Days	0.157	0.157	$20	$20
Work Loss Days	0.027	0.027	$8	$8
School Loss Days	0.209	0.209	$365	$365
Total Health Effects	-	-	$6,373	$9,003

As part of this analysis, the Evaluation Team also examined health benefits within DACs, which may be disproportionately burdened by sources of pollution (including air pollution from ICE vehicles). Because COBRA estimates effects at only the county level, the Evaluation Team disaggregated the health benefits by census tract using the relative population of each tract from the most recent ACS. For example, we allocated 10% of the value of the health benefits to a census tract with 10% of the county's population. The Evaluation Team then estimated the total benefits allocated to DACs and non-DACs.[75] This approach assumes that the benefits of emissions reductions are distributed evenly throughout the county. If the sites are located in DACs, and the emissions reductions are greater in the tracts near the sites, this approach understates the potential benefit to DACs. Additional information about emissions dispersion within counties would provide more precise estimates of health benefits to DACs and non-DACs.

In our analysis, Los Angeles County had 35% of the total benefits, followed by Orange County (22%), Riverside County (12%), San Diego County (9%), and San Bernadino (8%). Overall, 27% of the total benefits are in DACs.

[75] DAC census tracts are defined as those included in the SB 535 Disadvantaged Communities List (2022), which includes DAC categories for CalEnviroScreen 4.0 Top 25%, CalEnviroScreen 4.0 High Pollution Burden Score and Low Population Count, and 2017 Disadvantaged Community (CalEnviroScreen 3.0 only).

Highlights

- Cumulative health benefit estimates in California in terms of monetary benefits produced by the Charge Ready Schools sites range from $6,373 to $9,003.
- Los Angeles County had 35% of the total benefits, followed by Orange County (22%), Riverside County (12%), San Diego County (9%), and San Bernadino (8%).
- The proportion of overall benefits attributed to DACs for the program to date is 27%.

Utility Staff Insights

In addition to monthly check-in calls with key SCE staff to discuss the status of the Schools and Parks Pilots, the Evaluation Team also conducted a close-out interview with staff in February 2026 to review overall Pilot challenges and successes in EY2025.

Schools Pilot

Challenges for the Schools Pilot, which completed construction of all sites in 2025, surrounded final construction, maintenance, operational, and vendor coordination barriers. They include vandalism, clarification of maintenance responsibilities, compliance and liability concerns, and communication issues with vendors:

- **Vandalism.** SCE staff reported that at least one site experienced vandalism in 2025. The site had damage to charging cables; however, staff reported installing mitigation measures such as cable shielding to address these issues. According to SCE staff, repair costs due to vandalism continue to strain the program budget because these repairs are not covered by warranty, meaning SCE must pay for repairs out of the program budget.
- **Ownership Models and Maintenance Responsibilities.** With all Charge Ready Schools sites having finished construction and transitioning to long-term maintenance in 2025, staff reported an ongoing need to clarify the responsibility structure between SCE, EVSE providers, and schools. For example, the program team reported that the EVSE providers often invoice schools instead of SCE for maintenance costs due to a lack of clarity on warranty coverage. The unexpected maintenance costs that result from miscommunication and the need for increased coordination between SCE, EVSE providers, and schools, have added strain to the program's budget. Program staff continued holding conversations, both internally and with EVSE vendors and site hosts, to ensure proper oversight and handling of maintenance issues. At the end of 2025, no formal decisions about ownership structures had been made; however, SCE staff are planning to continue discussions in 2026.
- **Compliance and Liability Issues.** SCE staff noted that compliance with hardware standards has become particularly complicated due to uncertainty in the regulatory environment around compliant versus noncompliant hardware. Owners of commercial chargers can be liable for compliance violations despite not having direct control over their hardware. In response, SCE staff have strategically secured a reliable vendor who is up to date with compliance requirements and can perform testing at Schools Pilot sites.

- **Vendor Communication.** In 2025, SCE staff reported significant challenges with communicating with EVSE providers, noting general volatility in the charging industry. High turnover and a lack of a main point of contact at EVSE companies meant that SCE program staff and site hosts had to repeatedly explain issues to a new customer service agent each time they reached out. SCE staff attempted to escalate these issues by requesting manager-level contact. These communication barriers have contributed to delays in repairs at Schools Pilot sites.

SCE staff also noted successes with the Schools Pilot in 2025.

- **Final Sites Completed.** In 2025, SCE energized the final eight sites, completing the construction for the Schools Pilot and meeting port and DAC goals.
- **School Curriculum.** Beginning in 2023 and continuing through 2025, SCE, in partnership with TEC, promoted the EV-focused Schools Pilot Curriculum (primarily designed in 2022). TEC proactively engaged schools by conducting in-person and virtual outreach to the district. In June 2025, with the energization of the final Schools Pilot site, SCE officially closed out the school curriculum. In total, SCE staff successfully enrolled eight educators at eight different schools in the curriculum, reaching 1,210 students. The promotion and adoption of the curriculum allowed SCE staff to continue to foster positive relationships with schools.
- **Increased Touchpoints with Schools.** Beginning in 2024 and continuing with the remaining sites that were completed in 2025, program staff held joint onboarding training sessions with EVSE providers as part of an effort to improve communication with site hosts. The training allowed SCE staff to explain SCE's role and to provide an overview of the program's steps to prepare site hosts for the completion of construction and to align on maintenance and operation processes. This practice has helped EVSE providers maintain good relationships with schools in addition to increasing SCE program team's communication with schools.
- **Ongoing Interest in Electrification.** In previous evaluation years, SCE staff reported positive word-of-mouth promotion of installed chargers, which sometimes led to districts exploring the possibility of installing more chargers at existing sites, new sites at different schools, or both. In 2025, SCE noted that some schools who first installed chargers through the Pilot have expanded their electrification offerings by participating in other SCE charging programs.

Parks Pilot

In 2025, most of the program's activity was focused on finalizing site design, permitting, and planning for construction. At the end of the year, most sites were in the permitting, easement, and final review stages. Challenges for the Parks Pilot mainly revolved around design and permitting delays and coordination with state and local Parks staff, which caused site construction to be delayed until the second half of 2026:

- **Cross-Jurisdiction Coordination.** Since the MPA was signed in 2022, SCE staff have primarily been coordinating with local districts on design plans and permitting. While they reported continuing to navigate varying needs across sites as in 2024, SCE staff also noted that coordinating with both site-specific and state-level staff presented some challenges in the first half of 2025. Staff turnover at the DPR and the handoff from State Parks to district staff, which have led to inconsistencies in permitting processes across local jurisdictions, has caused delays in securing approved permits, which in turn delays environmental review and easement processes.

SCE staff also mentioned that internal coordination issues in 2025 caused delays with the environmental review process.

- **Site Capacity Issues.** Staff noted that one site had initially planned to install DCFCs, but capacity issues prevented the fast-charging ports from being installed. To ensure site viability, SCE reduced the port count and adjusted the total to 15 L2 chargers.
- **Environmental Hazards.** In 2025, several districts with planned sites experienced wildfires, which both impacted planned site locations and reduced the resources available to SCE and the Parks Pilot from local districts due to changing priorities. Additionally, in early 2025, SCE reduced engagement with customers located in areas impacted by wildfires, which slowed down the site planning process.
- **Design Plan Revisions.** SCE staff shared that several sites had to redo their design plans due to capacity constraints that limited the viability of installing fast charging ports, which moved these sites back into the final design phase at the end of 2025. This led to higher design costs than expected for the year.
- **Increased Permitting and Design Costs.** In 2025, spending for the Parks Pilot was driven primarily by design, permitting, and costs associated with government lands, including environmental reviews and easements.
- **Timeline Concerns.** SCE staff noted that Parks Pilot sites tend to have strict construction timelines, and Parks staff often want to avoid construction during the busy period from May to October. This requirement continues to contribute to timeline delays for site construction going into 2026.

Despite these challenges, SCE staff reported that overall, 2025 was a productive year for the Parks Pilot due to several major successes:

- **Flexibility with Design Plans.** SCE staff noted that their approach to design planning enabled them to work efficiently with the sites, incorporating necessary changes and securing approvals quickly when revisions were required.
- **Planning for Anti-Vandalism Measures.** Due to lessons learned with the Schools Pilot, SCE has begun to discuss measures to mitigate vandalism at Parks Pilot sites to implement once the sites are constructed in 2026.
- **Newfound Momentum**. In 2025, SCE staff reported a newfound commitment to the Parks Pilot from both state and district Parks staff and the availability of new resources with staffing secured at the end of 2025, setting the program up for a successful 2026. They expressed optimism for the Parks Pilot's momentum going forward.

Highlights

- **Schools Pilot:** Despite some issues with vandalism, regulatory compliance, and communication with vendors in 2025, SCE successfully completed the remaining eight sites, meeting the Pilot's port and DAC goals.
- **Schools Pilot:** With many Charge Ready Schools sites having finished construction and transitioning to long-term maintenance in 2024, there has been an ongoing need to clarify responsibility structure between SCE, EVSE providers, and schools. As in 2024, SCE held joint training sessions for the final Schools sites with EVSE providers to improve communication and clarify roles and responsibilities for the sites in 2025.
- **Schools Pilot:** SCE continued to receive positive feedback from participating schools and saw increased interest in chargers and electrification.
- **Parks Pilot:** Despite some delays due to design changes and permitting challenges, in 2025 SCE continued to plan for construction in 2026.
- **Parks Pilot:** Continuing from previous evaluation years, cross-jurisdiction coordination contributed to delays in the design and permitting processes. However, SCE was able to engage the correct stakeholders at the state and district levels and move forward with finalizing design plans and securing the necessary permits for Parks Pilot sites.

4.2.3. Lessons Learned

Schools and Parks Pilot

Schools and Parks Pilot program staff mitigated shifting costs and completed sites for both pilots. As the Schools Pilot sunsets, cost pressures have shifted from construction to ongoing maintenance expenses that were not fully accounted for in the original program design**.** SCE began the Schools Pilots during the COVID-19 pandemic, which had unprecedented economic impacts across nearly every market. As noted in previous years, SCE staff identified effective strategies to mitigate construction costs. In 2025, with all Schools Pilot sites constructed, unexpected costs emerged. Vandalism at Schools Pilot sites has resulted in damage to charging cables, and because repair costs are not covered by warranty, SCE has had to pay for repairs out of the program budget.

For the Parks Pilot, spending in 2025 was driven by design, permitting, and costs associated with government lands including environmental review and easements. Rising costs for construction labor and equipment, along with participant preferences for equipment such as DCFCs at Parks Pilot sites, drove up site costs. Several sites required design plan revisions due to capacity constraints that limited the viability of installing DCFC ports, moving sites back into the final design phase and leading to higher-than-expected design costs. Despite these challenges, SCE pilot staff successfully completed the remaining eight Schools Pilot sites, meeting the pilot's port and DAC goals, and moved forward with finalizing design plans and securing permits for Parks Pilot sites.

Schools Pilot

Upon completion of the eight 2025 sites, SCE staff met the Schools Pilot's port goal, made significant progress toward its site goal and continued to meet DAC goals. The pilot now includes 30

activated sites, achieving 75% of the per se reasonableness goal of 40 sites. With 78 additional ports installed in EY2025, the pilot reached a total of 250 L2 charging ports, meeting 100% of the port goal. Three of 8 sites activated in 2025 were in a DAC, reducing the cumulative share of DAC sites to 53% but still exceeding the pilot's per se reasonableness goal of 40%.

The Schools Pilot sites are helping to displace petroleum, reduce GHG and local emissions, and achieve nominal health impacts overall and within DACs. SCE's Schools Pilot sites to date have displaced over 58,000 gallons of petroleum, with 50% of this displacement within DACs. In addition, all pilot-to-date sites have resulted in an estimated total GHG emissions reduction of 84%, of which 50% occurred within DACs. These sites also contribute to lowering local emissions, with CO showing the most prominent projected reduction of almost 6,700 kg over a ten-year period. Overall, 27% of the health benefits from the Schools Pilot sites to date are in DACs with monetary health benefits ranging from $6,373 to $9,003.

SCE's Schools Pilot has a nominal, but growing, influence on neighborhood EV adoption. In EY2025, the Schools Pilot increased the number of operational sites by eight, bringing the pilot total to 30. Since its inception, the Schools Pilot contributed to the EV adoption of 85 EVs for households neighboring the infrastructure.

Utilization of Schools Pilot sites is rising, with a growing number of sessions and increases in total consumption and demand. With eight new sites activated in the SCE Schools Pilot, a total of 550 kW was installed in 2025, bringing total installed capacity to 1,750 kW in the program to date. Overall energy consumption increased by 40% to 358 MWh in 2025 from 252 MWh in 2024, and on average more energy is dispensed per charging sessions compared with prior years. Over 40,000 charging sessions have taken place in the pilot to date, with approximately one-third of sessions occurring in 2025. Monthly energy consumption rose steadily throughout 2024, from approximately 16 MWh in January to 27 MWh at the end of the year, with dips in consumption in the summer months, coinciding with breaks in the school year. Demand peaked at 322 kW in 2025, up from 215 kW in 2024. Charging activity outside of school hours at some sites, including on the weekends, indicates that sites are supporting the local community in addition to school employees.

Parks Pilot

Parks Pilot design and permitting faced coordination and resource challenges, but SCE staff continued advancing final design plans and permit approvals. As noted in previous years, discussions about individual site design with district-level DPR staff generally progressed well. However, coordination across district- and state-level staff, combined with DPR staff turnover, caused minor delays during site planning and implementation. The handoff from State Parks to district staff also created inconsistencies in permitting processes across local jurisdictions. These inconsistencies delayed permit approvals and, in turn, slowed related environmental review and easement activities. In addition, several districts with planned sites were affected by wildfires in 2025. These events altered some planned site locations and reduced the capacity of local districts to support the Parks Pilot because priorities had shifted. Despite these challenges, SCE engaged the appropriate state and district stakeholders and continued finalizing design plans and securing the necessary permits for Parks Pilot sites.

5. Pacific Gas & Electric Transportation Electrification Programs

5.1. EV Fleet Program

5.1.1. Overview

This overview provides a detailed description of the PG&E EV Fleet program; summaries of the program implementation process, performance metrics, materials, and budget; and a timeline of major milestones. Following the overview are detailed findings, highlights, and lessons learned.

Program Description

Per Decision 18-05-040, PG&E designed the EV Fleet program to provide infrastructure for fleet electrification at a low or no cost to participants. Launched in June 2019, the program encompasses incentives and rebates, site design and permitting, construction, activation, and maintenance of program-funded make-ready infrastructure. The program intends to help fleets install EV charging infrastructure easily and cost-effectively, saving money, eliminating tailpipe emissions, and simplifying vehicle maintenance. PG&E's EV Fleet program has an approved budget of $236.3 million. The program originally aimed to complete 700 sites; however, in 2024 Resolution E-5257 reduced this goal to support fleet electrification for a minimum of 375 sites. The vehicle goal remained consistent at 6,500 medium-duty and heavy-duty (MDHD) EVs procured through the program to augment or replace vehicles in the fleet.

EV Fleet Program Target

Achieve a minimum of 375 sites supporting 6,500 MDHD EVs.

EV Fleet Program Design Goal

Accelerate adoption by providing fleet assistance to install EV charging easily and cost-effectively, saving money, eliminating tailpipe emissions, and simplifying maintenance.

Through the EV Fleet program, PG&E constructs all TTM infrastructure and, depending on the cost-effectiveness of each site, will do the same for BTM infrastructure. Otherwise fleet operators design, build, own, operate, and maintain BTM infrastructure. PG&E provides rebates for BTM infrastructure based on the number of vehicles the infrastructure supports, capped at 80% of the cost of the BTM infrastructure. Additional charger rebates of up to 50% of the cost of the EVSE are available for transit agencies, school districts, and fleets located in DACs that are not operated by Fortune 1000 companies.

The EV Fleet program requires participating customers to lease or purchase at least two MDHD EVs to add to or replace existing vehicles in their fleet. Applicants are not restricted by industry. Fleets must own or lease the property where the chargers are installed, operate and maintain the infrastructure for 10 years, provide data related to EV usage for five years, and use EVSE that meets CPUC safety checklist requirements, among other participation requirements. PG&E offers participating sites EV-specific TOU rates (BEV-1 and BEV-2).

The SB 350 Decision specifies how PG&E should distribute EV Fleet program funding. The infrastructure budget must allocate a minimum of 15% for transit agencies,[76] a maximum of 10% for forklifts, and a minimum of 25% on installations in DACs in PG&E's territory.

Implementation

Figure 135 shows the key steps in the EV Fleet program implementation process. There were no major changes to the implementation process in 2025.

Figure 135. PG&E EV Fleet Program Implementation Process

Preliminary Design Phase

1. The customer applies through the online application portal.
2. PG&E develops an initial design and cost estimate for the site based on the scope and site characteristics.
3. PG&E determines if the site is eligible for TTM only, TTM plus incentives, or TTM plus BTM.
4. The customer secures a vendor for site/infrastructure construction.
5. The customer and PG&E sign the contract.

Final Design and Execution Phase

1. The customer designs BTM infrastructure and either the customer or PG&E begins the permitting process.
2. PG&E finalizes TTM design.
3. The customer constructs BTM infrastructure.
4. PG&E constructs TTM infrastructure.
5. PG&E turns on service.
6. The customer commissions the EVSE.
7. PG&E issues rebates.

Program Performance Metrics

The Evaluation Team reviewed the sites participating in the PG&E EV Fleet program and organized them by program status. Table 58 provides the count of sites in the PG&E EV Fleet program by completion status as of December 31, 2025.

[76] In December 2025, PG&E filed AL-7786-E requesting to reduce the transit agency minimum from 15% to 10% of the infrastructure budget.

Table 58. PG&E EV Fleet Program Complete Site Count by Status

Site Status	EY2025	Program to Date
Utility Construction Complete	72	182
Activated	60	170
Operational	57	159
Closed Out	84	158

In EY2025, the PG&E EV Fleet program received an additional 135 applications, signed contracts for 95 sites, and activated 60 sites to support 1,700 MDHD EVs across five market sectors. This increased the total number of applications received in the program to date by the PG&E EV Fleet program to 654 and the total number of contracts executed in the program to date to 393.[77] As Table 59 shows, 40% (24 of 60) of sites in the EV Fleet program activated in EY2025 are in a DAC, and 42% (72 of 170) of sites activated in the program to date are located within a DAC.

Table 59. PG&E EV Fleet Program Activated Sites by Market Sector in EY2025 and Program to Date

Market Sector	EY2025		Program to Date	
	Number of Sites in DAC	Number of Sites in Non-DAC	Number of Sites in DAC	Number of Sites in Non-DAC
Forklift	3	1	7	3
Heavy-Duty Vehicle	2	2	14	8
Medium-Duty Vehicle	9	11	22	28
School Bus	6	20	20	48
Transit Bus	4	2	9	10
TRU	-	-	-	1
Total	24	36	72	98

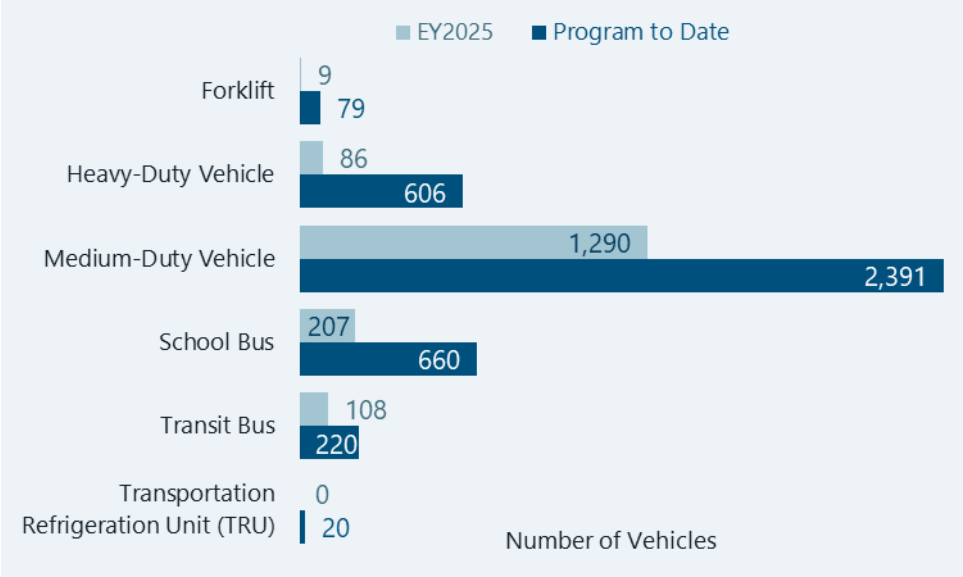
For EY2025, the highest activation rate in the PG&E EV Fleet program came from the school bus market sector, which represented 43% of activated sites. Medium-duty vehicle fleets represented 33%, followed by transit bus fleets with 10% of EY2025 activated sites. Heavy-duty vehicles and forklift fleets each represented 7% of EY2025 activated sites.

School bus fleets continue to have the highest participation in the PG&E EV Fleet program, which represents 40% of all activated sites in the program to date. Medium-duty vehicle fleets are the second most common market sector overall, with 29% of all activated sites. Heavy-duty vehicle fleets account for 13% and transit bus fleets for 11% of activated sites, while forklift sites represent only 6% of activated sites in the program to date. The TRU market sector is the least represented in the program, with only one activated site as of December 31, 2025.

[77] Total applications do not include any applications that were put on hold. Total contracts do not include sites that were rejected or withdrawn

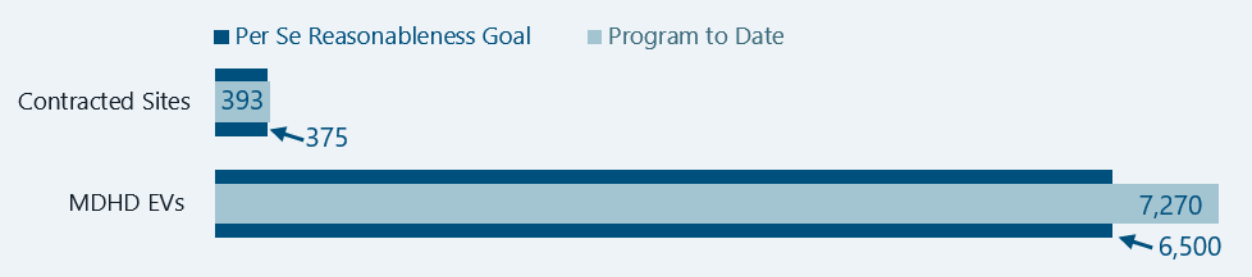
Through the EV Fleet program, PG&E installed charging infrastructure to support 1,700 MDHD vehicles across five market sectors in EY2025 based on five-year VAPs submitted by customers at the time of application. This brings the total number of supported MDHD EVs in PG&E's EV Fleet program to 3,976 per VAPs. In EY2025, medium-duty vehicle market sector accounted for most vehicles, followed by school bus, transit bus, heavy-duty vehicle, and forklift market sectors, as shown in Figure 136.

Figure 136. PG&E EV Fleet Program Vehicles Supported by Market Sector, EY2025 Sites



The PG&E EV Fleet program had 170 activated sites in the program to date, supporting the electrification of 3,976 MDHD vehicles per customers' VAPs. As shown in Figure 137, the 393 contracts signed in the EV Fleet program meet 100% of the program's per se reasonableness goal of 375 sites and could support 7,270 MDHD vehicles, exceeding 100% of the program's per se reasonableness goal of 6,500 vehicles electrified. The total 654 customer applications could also satisfy the program's site goal and electrified vehicles goal.

Figure 137. PG&E EV Fleet Program Per Se Reasonableness Site and Vehicle Goal Progress



A total of 1,311 charging ports were installed at the 60 sites activated in EY2025 to support the 1,700 electrified MDHD vehicles. In the PG&E EV Fleet program to date, 3,040 L2 and DCFC ports have been installed at activated sites to support charging of 3,976 MDHD EVs in the EV Fleet program, equating to roughly 1.6 vehicles per charging port.

The CPUC established six phases in program timelines per the SB 350 reporting template. As displayed in Table 60, at the end of 2025 nearly two thirds of customer applications (63%) were in the first three program phases (application review, site assessment, and contract issuance), while the remaining sites were in the second three program phases (design and permitting, construction complete or activation).

Table 60. PG&E EV Fleet Program Sites and Vehicles by Program Phase as of December 31, 2025 [a]

CPUC Program Phase	Number of Sites	Total Number of EVs Supported
Application Review	155	3,054
Site Assessment	44	499
Contract Issuance	100	1,834
Design and Permitting	170	2,369
Construction Complete	3	13
Activation [b]	182	4,150

[a] This table does not include sites that were waitlisted or on hold as of December 31, 2025.
[b] The number of sites in the activation phase exceed the number of activated sites in the program to date, because this table includes sites that have entered but have not yet completed this program phase.

Table 61 displays the median durations per program phase (measured in calendar days) for EY2025 and PTD activated sites. The column labeled EY2025 refers to sites activated in 2025. The Program to Date column refers to all sites activated from the initiation of the program through December 31, 2025.

Values in Table 61 provide insight into program phase length trends over time. Sites in each column did not necessarily pass through each phase in the same calendar year. For example, some sites in the EY2025 column may have passed through design and permitting in 2025 while others passed through in 2024. For sites activated in 2025, the design and permitting program phase had the longest median duration, while the remaining five program phases had roughly similar median durations.

Table 61. PG&E EV Fleet Program Median Calendar Days per Phase for EY2025 and PTD Sites

CPUC Program Phase	Median Calendar Days [a]	
	EY2025 [b]	Program to Date [c]
Application Review	53	38
Site Assessment	51	45
Contract Issuance	32	44
Design and Permitting	528	475
Construction Complete	18	26
Activation	17	21

[a] Sites that received only an incentive through PG&E's EV Fleet Program and did not undergo TTM upgrades are excluded from the program phase duration analysis, because they experienced a shorter program process.
[b] "EY2025" represents the data for the sites activated in 2025.
[c] "Program to Date" represents the data from all activated sites from program inception for all program years.

Median durations also vary by individual market sectors. For instance, forklift applications took a median of 386 days to complete the design and permitting phase, while medium-duty vehicle applications took a median of 614 days to pass through this program phase. The median durations per program phase in EY2025 were similar to durations for the program to date for all phases. The design and permitting phase continues to be the longest phase, with a median of 475 days for PTD sites, or 73% of the overall implementation timeline.

Figure 138 expands the analysis of program phase durations for EY2025 by displaying the average number of calendar days (denoted by X), the median calendar days (middle line in box), first quartile (bottom of box), third quartile (top of box), minimum (bottom tail), maximum (top tail), and outliers (dots). Program applications experienced far greater variation in completion time within the design and permitting phase than in any other program phase. As previously mentioned, this could stem from this phase's external review and substantial back-and-forth communications with applicants to finalize site layout, design, and BTM infrastructure.

Figure 138. PG&E EV Fleet Program Calendar Days per Phase for EY2025 Sites

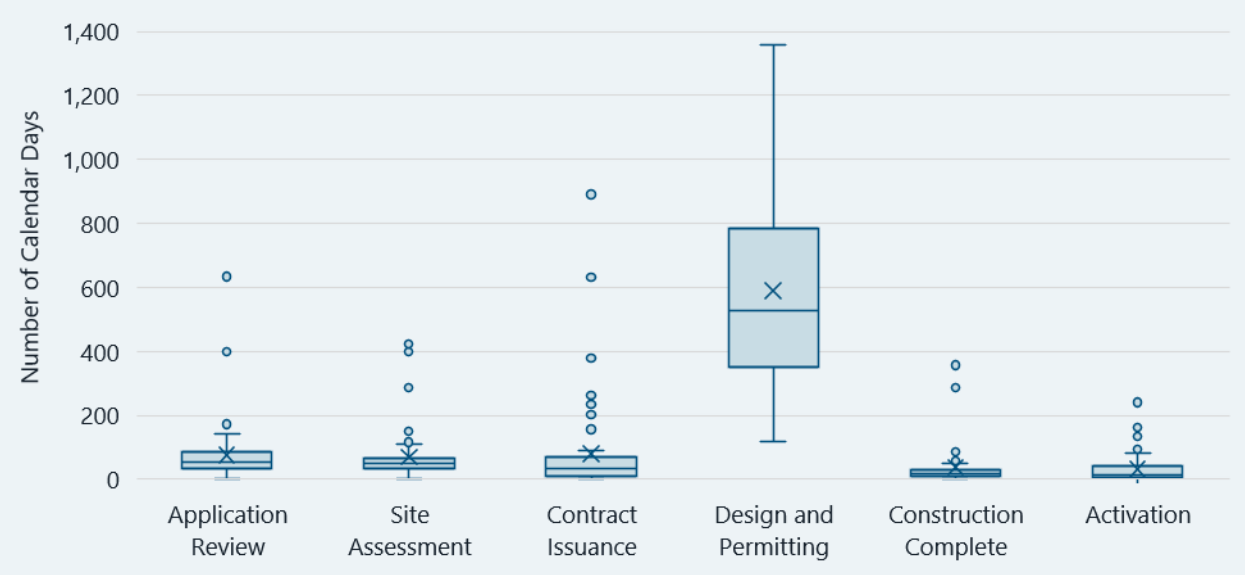


Table 62 displays the median number of calendar days that the EV Fleet program took from start to finish (application review to activation) for activated sites across five market sectors in EY2025 and in the program to date. The overall median start-to-finish timeline for site activation for EY2025 sites was 840 calendar days, with the shortest timeline for forklift sites at 533 days and the longest for medium-duty vehicle sites, which took 1,027 days to complete all program phases. The overall median start-to-finish timeline for site activation for PTD sites was 798 calendar days, ranging from 393 days for TRU applications to 1,166 days for transit bus applications.

Table 62. PG&E EV Fleet Program Median Duration for Site Activation by Market Sector for EY2025 and PTD Sites

Market Sector	EY2025		Program to Date	
	Median Duration Start-to-Finish (Calendar Days)	Number of Activated Sites	Median Duration Start-to-Finish (Calendar Days)	Number of Activated Sites [a]
Forklift	533	4	590	10
Heavy-Duty Vehicle	847	4	817	22
Medium-Duty Vehicle	1,027	19	896	43
School Bus	744	26	723	66
Transit Bus	1,004	4	1,166	15
TRU	-	-	393	1
All Market Sectors	840	57	798	157

[a] Sites that received only an incentive through PG&E's EV Fleet Program and did not undergo TTM upgrades are excluded from the program phase duration analysis, as they experienced a shorter program process.

Program Materials Summary

This section highlights findings from the review of program material and ME&O activities PG&E staff conducted in 2025. PG&E staff continued customer education and outreach efforts from previous years to increase program participation through targeted engagement in events and leads generation:

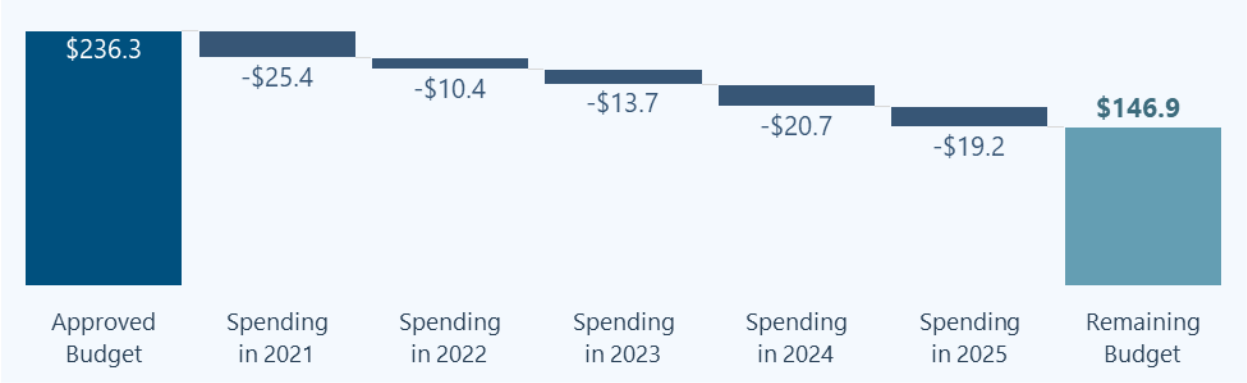
- **Event Attendance.** PG&E staff attended and hosted multiple events in 2025, including ride and drives, conferences, workshops, and webinars. In total, PG&E staff attended 10 events and seven webinars, representing both EV Fleet and EV Advisory Services (EVAS) at several of the events.
- **Marketing Scale-Back.** The program team took a broad marketing approach but significantly scaled back outreach after receiving a surge of applications (27 in the first quarter of 2025, and 85 in the second quarter), which strained the program budget and led to the creation of a waitlist. To avoid generating additional leads, the team reduced EV Fleet–focused marketing and shifted to more targeted, transit agency-focused efforts. By the middle of the second quarter, most marketing efforts for EV Fleet had ceased, while marketing for EVAS continued to expand. Monthly EV Fleet interest form submissions in 2025 reflected the drawdown in marketing, peaking in June with 79 submissions and then not exceeding 22 for any month through the end of the year.
- **Transit Agency Focus.** As mentioned above, PG&E staff continued marketing efforts for transit agencies while scaling down other efforts to work toward the Utility's requirement of 15% of its infrastructure budget serving transit agency customers. Such targeted efforts included attending Cal Act and California Transit Association conferences and hosting transit-specific webinars with CARB. In an effort to capture new transit agency customers, PG&E staff focused outreach on transit agencies that they had either not engaged with or had engaged with but that had not advanced to the application stage.
- **Website Metrics.** In 2025, the EV Fleet program website attracted 3,780 unique visitors and 6,114 total page views. Prospective participants submitted 305 EV Fleet interest forms over the course of the year

- **Post-Activation Customer Survey.** Since 2021, PG&E has conducted an annual survey to assess customer satisfaction with the overall program and several key components, including PG&E's attention to safety, interactions with PG&E staff, experience with EV service providers, rebate and incentive processing, rate decision-making, and project duration. The survey received 14 responses in 2025 and customer feedback with the program was largely positive. While overall satisfaction with the program was high, EV Fleet program participants expressed the most frustration with receiving the right information to decide which PG&E rate plan to select and with the duration of the project from contract signing through charger energization. Several customers mentioned working with PG&E staff as easy and a highlight of the program. In a survey response reflective of several others' responses, one customer said, "besides the timeline, everything was smooth and I found the project managers very easy to work with." In 2024, the post-activation survey only received three responses, and all customers were similarly satisfied with all aspects of the program including the timeline.

Budget Summary

As shown in Figure 139, from program inception through December 31, 2025, PG&E spent $89.4 million of the approved $236.3 million budget for the EV Fleet program. In 2025, the program spent $19.2 million.

Figure 139. PG&E EV Fleet Program Budget (Millions USD) as of December 31, 2025



Timeline

Since the beginning of the program PG&E has filed four Advice Letters. In 2022, PG&E and SCE jointly filed AL 6546-E for changes to program metrics but received a protest from the CPUC. In response, PG&E filed AL 6524-E-A in April 2023 to address CPUC concerns from the initial Advice Letter. Although the CPUC granted the timeline extension in August 2023, it denied PG&E's proposal to eliminate the site requirements and to modify the vehicle purchase and conversion requirements. Therefore, PG&E filed AL 7121-E on December 28, 2023, as a response to the rejected modifications for site goals in AL 6546 E A. Instead of eliminating the site requirement, AL 7121-E proposes a reduction of the site goal minimum. In October of 2024, the CPUC approved AL 7121-E, which reduced the minimum number of sites to 375.

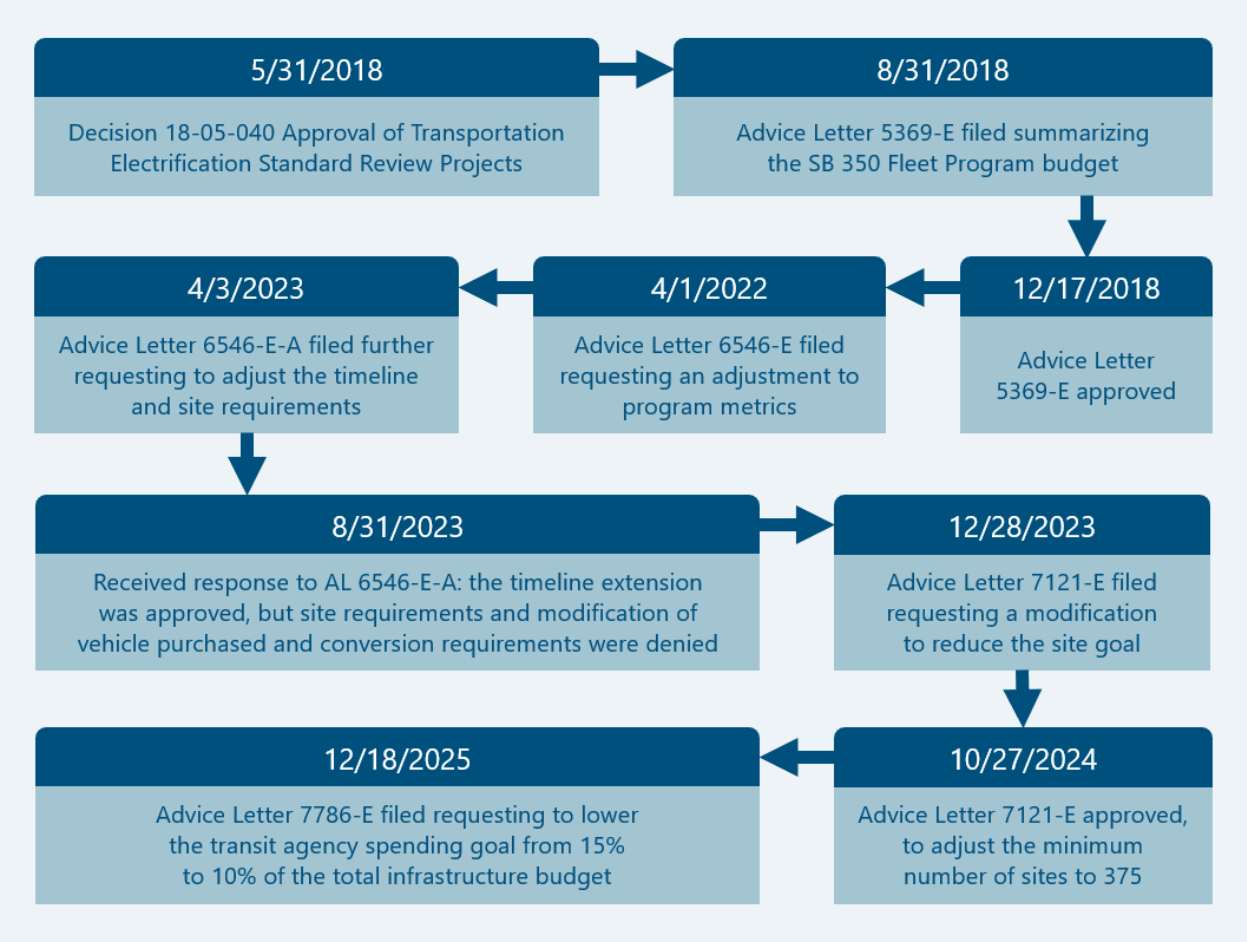
In July 2025, PG&E implemented a waitlist for non-transit applicants in response to the high volume of applications received in the first half of 2025 and plans to accept waitlisted applications through June 2026 as budget becomes available.

On December 5, 2025, the CPUC issued the Transportation Electrification Policy and Infrastructure (TEPI) Decision, D.25-12-005, which removed the vehicle purchase requirement for MDHD programs, including EV Fleet, and confirmed the customer enrollment deadline of December 31, 2026.

In December 2025, PG&E filed AL 7786-E to request a reduction of its goal of 15% of its infrastructure budget serving transit agencies to 10%, which the Utility viewed as achievable; this would make 5% of the budget available to waitlisted customers. PG&E was still awaiting a response from the CPUC as of the end of the year.

Figure 140 shows all major milestones from the beginning of the program.

Figure 140. PG&E EV Fleet Program Key Milestones



5.1.2. Findings

This section provides findings from the Utility staff interviews, surveys, and site visits and deep dives. The Evaluation Team also provides insights from the co-benefits and co-costs analysis, site costs, grid impacts, petroleum displacement, GHG and criteria pollutant reductions, health, and net impacts.

Table 63 presents key impact parameters for EY2025 and the program to date. Annual estimates of impacts are provided for metrics calculated as part of the impact evaluation. The table also provides estimates of impacts across all sites included in the program population through 2025.

Table 63. PG&E EV Fleet Program Impacts Summary

Impact Parameter	EY2025 Sites [a]	EY2025 Sites Percentage in DAC	PTD Sites Actual	PTD Sites Actual Percentage in DAC
Population of Activated Sites	60	40%	170	42%
Sites Included in Analysis	51	37%	157	41%
Ports Installed in Analyzed Sites	1,285	26%	2,997	37%
EVs Supported [b]	1,644	23%	3,895	43%
Electric Energy Consumption (MWh)	10,814	24%	62,455	58%
Petroleum Displacement (DGE)	915,351	24%	5,755,797	59%
GHG Emissions Reductions (MT) [c]	6,863	24%	47,880	61%
NO_X Reduction (kg)	1,258	15%	29,844	64%
PM_{10} Reduction (kg)	28.3	27%	470	87%
$PM_{2.5}$ Reduction (kg)	26.5	27%	430	87%
ROG Reduction (kg)	268.9	33%	6,453	89%
CO Reduction (kg)	24,497	27%	414,191	56%

[a] Energy consumption, petroleum displacement, and emissions reductions are based on annualized data. Program-to-date results are based on actual data (see *Appendix B* for details).

[b] The Evaluation Team derived the EVs supported value from applicants' VAPs. This value represents the maximum number of vehicles expected to be supported by the charging infrastructure.

[c] GHGs include CO_2, CH_4, and N_2O multiplied by their respective GWP as defined by IPCC AR5 (see *Appendix B* for details).

Utility Staff Insights

In addition to monthly check-in calls with key PG&E staff to discuss the status of the EV Fleet program, the Evaluation Team conducted a close-out interview with staff in March 2026 to review overall program challenges and successes in EY2025. Staff identified several program challenges:

- **Transit Goal.** In 2025, PG&E staff faced challenges in achieving their program goal for 15% of their infrastructure budget to be used for public transit sites. In efforts to reach this goal, staff directed marketing to transit agencies and established a waitlist for non-transit applicants in July of 2025, slowing down customer acquisition activities for non-transit sites. Based on recruitment of transit applicants in 2025, staff determined that they would not achieve the 15% goal by the application deadline of June 2026 or enrollment deadline of December 2026. As a result, they filed an Advice Letter with the CPUC in December 2025 to reduce the goal to a more achievable 10% and reallocate the remaining budget to waitlisted sites.

- **Regulatory Changes.** In January of 2025, CARB withdrew its request for a Clean Air Act waiver for the state's ACF regulation in the face of federal government opposition. Staff noted that compliance with this regulation was the reason many participants had applied to the PG&E EV Fleet program, so its withdrawal led to the cancellation of some sites. The waiver withdrawal and subsequent site cancellations did not have as large of an effect on program performance as expected because many of PG&E's target customers for the program, such as schools, municipalities, and state agencies, were still required to adhere to state-level electrification regulations.
- **Load Management Outreach.** PG&E staff reviewed activated sites in 2025 to identify which sites could benefit most from behavior-change efforts and load-management education. Based on this review, staff selected several high-opportunity sites and attempted to pilot a load-management education session, though no sites responded. Although the pilot did not launch, this effort clarified the key parameters for identifying sites that need additional support. Building on this foundation, the EVAS team conducted targeted outreach in 2025 to activated EV Fleet program sites with high on-peak charging through the EVAS program. Getting responses from sites remained a challenge, and the team was able to engage only a small number of sites to discuss load management improvements.

PG&E staff also reported notable successes in 2025:

- **Material Lead Times.** Prior to 2025, long lead times for charging infrastructure, particularly switchgears, have been a pain point for program participants. In 2025, the program construction team reported lead times of around six to eight months, which, while still a challenge for customers, represents a significant improvement from the two-year lead times experienced following the COVID-19 pandemic.
- **Strong Program Enrollment.** Despite challenges with recruiting targeted transit customers and some site cancellations following the ACF withdrawal, the EV Fleet program maintained consistent applications and enrollment in 2025. Staff noted that municipalities and schools remained active participants, helping to maintain continued program momentum and interest in the face of broader deregulation.

Overall, PG&E staff noted that the EV Fleet program was critical to the success of many electrification projects that would have otherwise not proceeded due to insufficient funding. While staff acknowledged that EV Fleet does not provide enough funding to fully enable all sites, the program has been impactful in building electrification capacity and competency with customers.

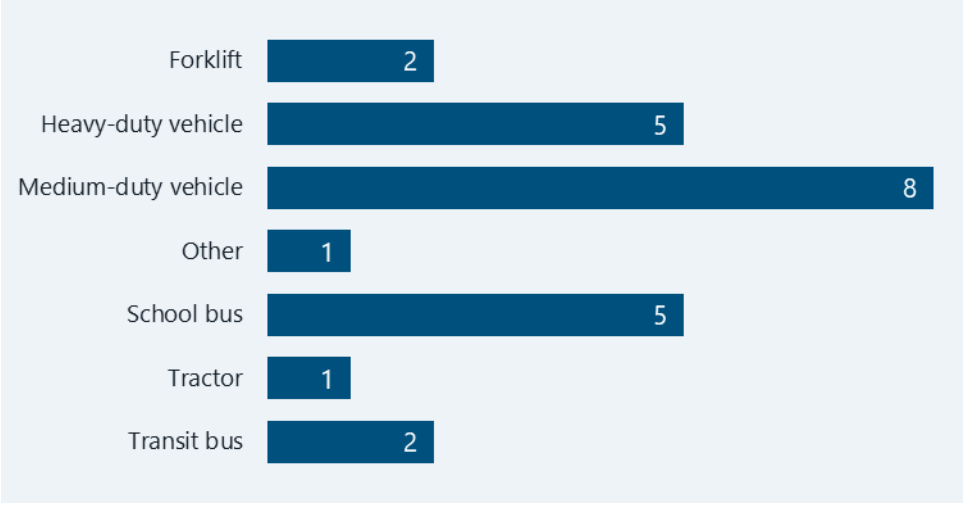
Highlights

- PG&E staff experienced challenges with recruiting transit customers to achieve its 15% infrastructure budget goal, leading staff to request lowering the budget requirement.
- Regulatory changes at the federal level, including the withdrawal of the ACF waiver, contributed to uncertainty among customers and some site cancellations, though many customers still faced other state-level electrification regulations which softened the impact and kept key customer segments, such as schools, municipalities, and state agencies, engaged.
- PG&E's EV Fleet program staff clarified how to identify high-opportunity EV Fleet sites for improved load management practices, better enabling outreach by the EVAS team.

Survey Results

The Evaluation Team asked participating fleet managers about their motivations for and barriers to electrification, satisfaction with and awareness of the program, experience with EVs and charging infrastructure, and perspective on the industry. The Team received 14 complete survey responses and five partial responses. The fleet managers surveyed represented companies with vehicles across six of the seven market sectors. Ten of these fleet managers reported that their fleets consisted of vehicles in one market sector, while six reported having vehicles in two or three sectors in their fleets. Figure 141 shows the number of fleet managers who reported having vehicles in each of the market sectors. Medium-duty vehicles were most commonly cited by respondents, with a third of fleet managers (six of 16) reporting them as part of their fleet.

Figure 141. PG&E EV Fleet Program Participant Vehicle Types in Fleets

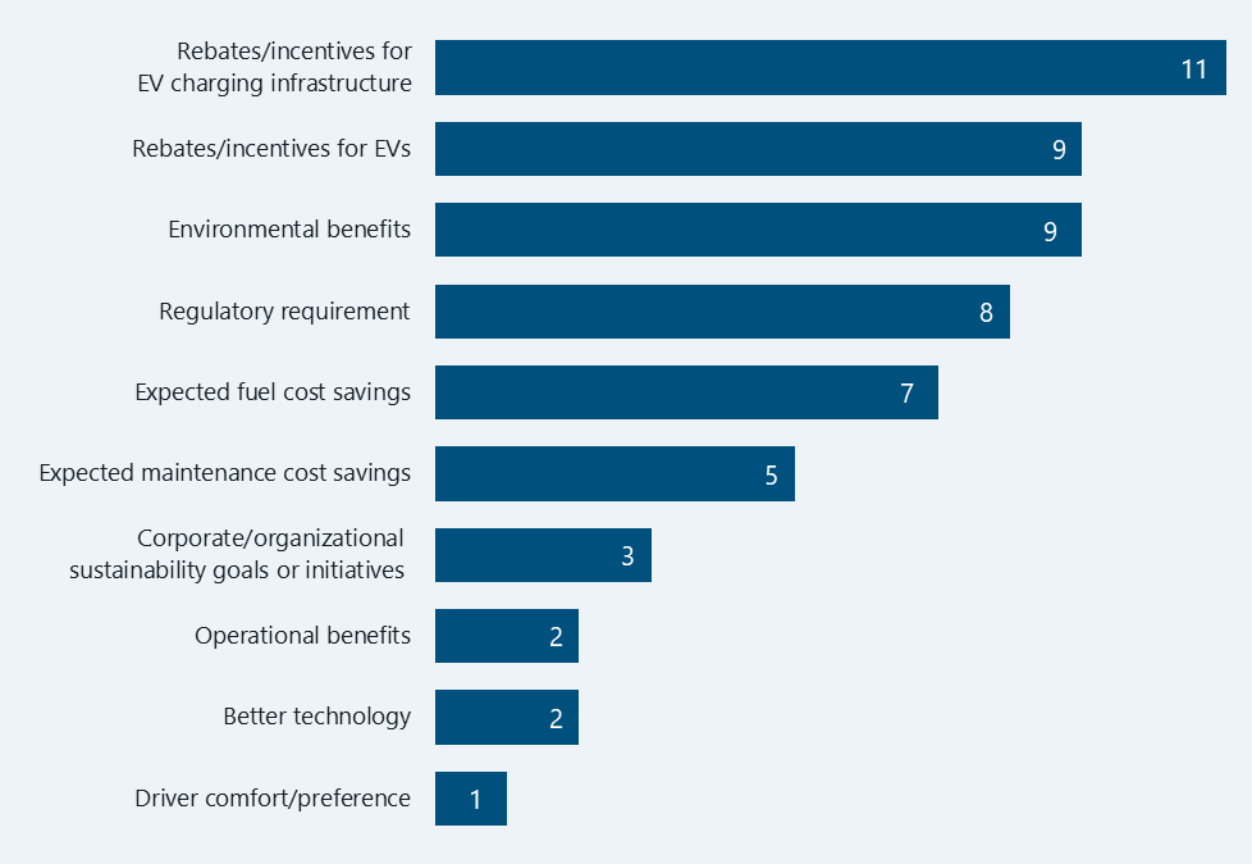


Source: Fleet Manager Survey Question A1 "What types of vehicles/equipment do you have in your fleet?" (n=16, multiple responses accepted)

Electrification Motivators and Barriers

The Evaluation Team asked fleet managers about their motivations for transitioning to EVs from ICE vehicles. As shown in Figure 142, the top motivator was rebates/incentives for EV charging infrastructure, cited by 11 of 14 respondents. The next most common motivators were rebates/incentives for EVs and environmental benefits, cited by nine fleet managers each. Regulatory requirement, expected fuel cost savings,[78] and expected maintenance cost savings were cited by eight, seven, and five fleet managers respectively. Top motivators were somewhat different than in EY2024 when regulatory requirement and corporate/organizational sustainability goals or initiatives were cited by nine and seven of 11 respondents, respectively, and in EY2023, when corporate/organizational sustainability goals or initiatives was the top motivator for three of four fleet managers. Rebates/incentives for EV charging infrastructure and environmental benefits have been among the top motivators each year since EY2021, except for EY2024.

Figure 142. PG&E EV Fleet Program Participant Motivators for Transitioning to EVs in EY2025



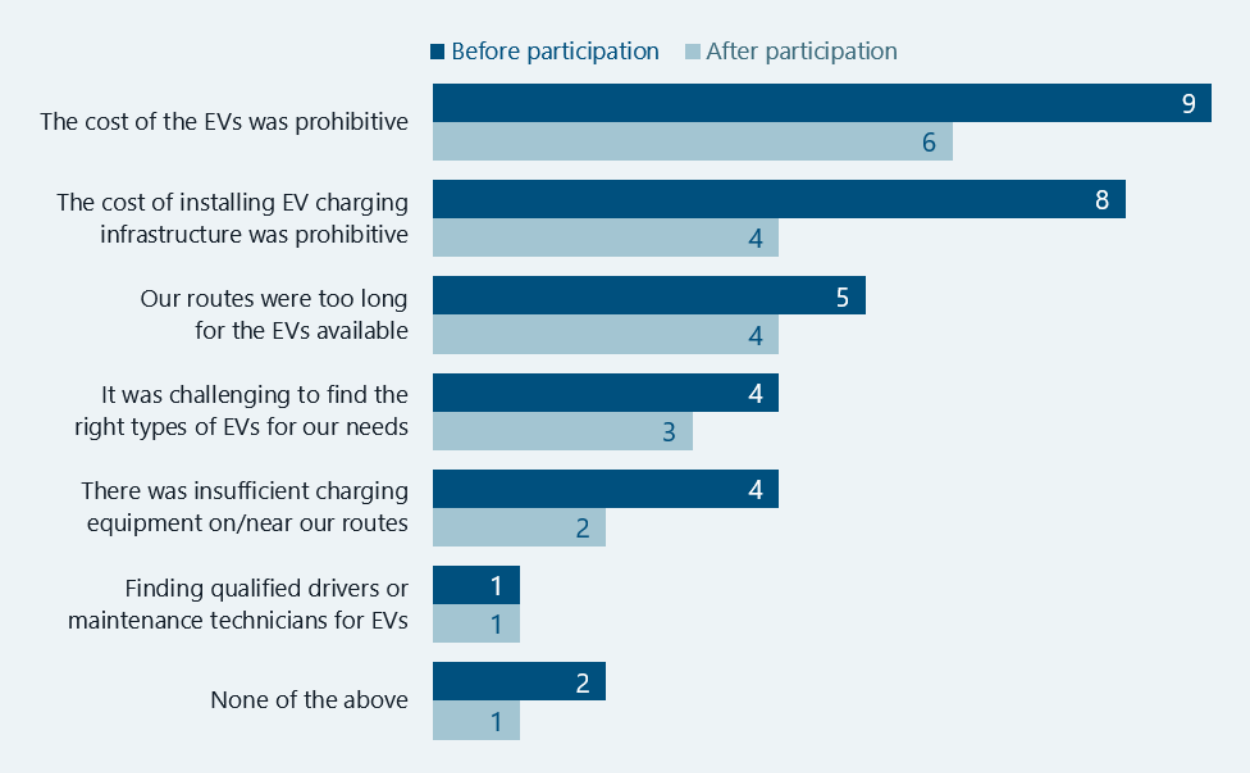
Source: Fleet Manager Survey Question C1 "Why did your fleet decide to transition to EVs?"
(n=14, multiple responses accepted)

The Evaluation Team asked fleet managers which barriers to electrification their fleets had faced before participating in the PG&E EV Fleet program and which remained after participation. Figure 143 shows that

[78] These surveys and interviews occurred in late 2025 and early 2026, prior to the volatility in global oil prices.

prior to participating, fleet managers found the cost of both EVs and installing EV charging infrastructure to be the biggest barriers to electrification, mentioned by nine and eight of 14 respondents, respectively. The next most commonly mentioned barrier to electrification was fleet managers' routes being too long for the EVs available, which was mentioned by five respondents. After participating, all barriers were mentioned by fewer fleet managers, but all remained for at least one fleet manager. Six of 14 fleet managers cited the cost of EVs was prohibitive as a barrier after program participation, and four respondents each mentioned the cost of installing EV charging infrastructure and routes being too long for the EVs available after program participation. Survey results are consistent with results in EY2024 when the cost of EVs and the cost of EV charging infrastructure were tied as the top barrier (each cited by seven of 11 fleet managers) and results in EY2023 when these costs were tied as the second top barrier (each cited by two of four fleet managers) before electrification. The cost of EV charging infrastructure and the cost of EVs were top barriers in EY2021, EY2022, and EY2023, among other categories such as EV routes being too long and the right types of EVs for their needs being hard to find.

Figure 143. PG&E EV Fleet Program Barriers to Electrification Before and After Program Participation in EY2025



Source: Fleet Manager Survey Questions F3 and F4 "Which of the following barriers to electrification did your fleet face before participating in the EV Fleet program?" and "You mentioned that the following were barriers to electrification before participating in the EV Fleet program. Do any of these barriers still exist after you participated in the program?" (n=14, multiple responses accepted)

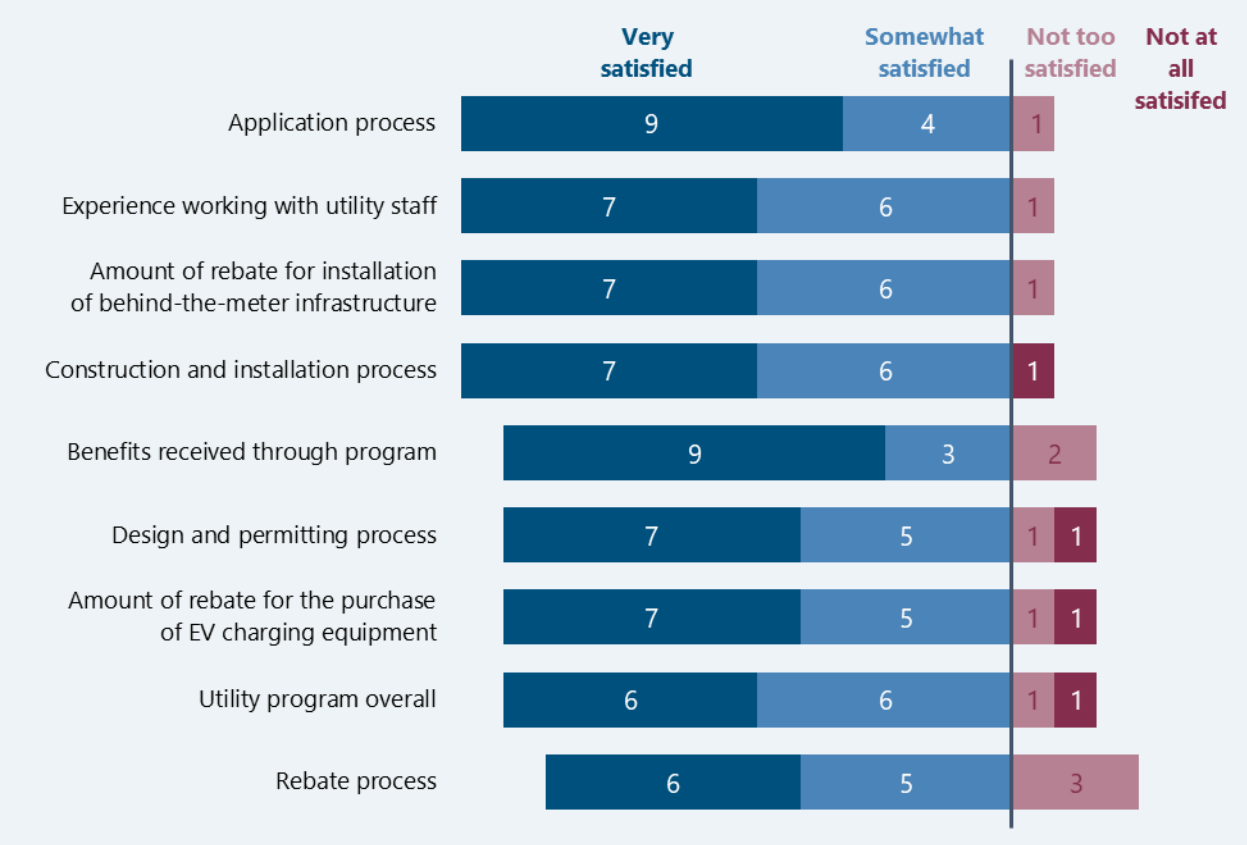
Program Satisfaction

The Evaluation Team asked fleet managers to rate their satisfaction with various elements of PG&E's EV Fleet program and the program overall. Fleet managers generally reported strong satisfaction across all program elements (Figure 144) and satisfaction with the program overall, with six managers rating themselves as *very satisfied* and six rating themselves as *somewhat satisfied*. Fleet managers reported the highest satisfaction with the application process, with nine respondents rating themselves as *very satisfied* and four as *somewhat satisfied*. The experience working with Utility staff, the amount of the rebate for the installation of BTM infrastructure, and the construction and installation process each received a rating of *very satisfied* by seven fleet managers. No more than two fleet managers said they were dissatisfied with any aspect of the program, aside from the rebate process, with which three fleet managers reported being *not too satisfied*. In previous evaluation years, all fleet managers who responded to this question reported being either *very satisfied* or *somewhat satisfied* with the rebate process.

The Evaluation Team also asked fleet managers to describe aspects of the EV Fleet program with which they were particularly satisfied or dissatisfied. Three fleet managers highlighted interactions with PG&E staff as an area of high satisfaction, with one mentioning that all their questions were answered clearly and that they were pleased with "how helpful everyone was." Another fleet manager appreciated that the program eliminated "most of the challenges previously associated with the need to increase electricity to the site." Two fleet managers expressed dissatisfaction with having to provide the same information several times throughout the application process. One fleet manager said they were frustrated with employee turnover at PG&E complicating project progress and communication, and another said they were dissatisfied with the performance of their EV chargers and EVs.

Satisfaction ratings in EY2025 were consistent with EY2024, EY2023, EY2022, and EY2021, which all also saw almost entirely positive feedback from fleet managers. The most notable change from EY2024 is that experience working with PG&E staff changed from being the aspect with the lowest satisfaction (two of 10 respondents rating themselves as dissatisfied) to the aspect with almost the highest satisfaction ratings in EY2025 (only one of 14 respondents rated themselves as dissatisfied).

Figure 144. PG&E EV Fleet Program Satisfaction with Program Elements in EY2025



Source: Fleet Manager Survey Question B1 "Thinking about your experience with the EV Fleet program, how satisfied are you with the following?" (n=14)

The Evaluation Team asked fleet managers how likely they were to recommend the EV Fleet program to another company on a scale of 0 to 10. Nearly half of respondents (six of 14) gave a rating of 10, meaning they had already recommended the program to other companies. One fleet manager rated their likelihood of recommending the program as 9, three rated it as 7 or 8, and four rated it between 1 and 6, resulting in a NPS of +21.[79] This is a drop from the NPS scores of +55 in EY2024, +75 in EY2023, +50 in EY2022, and +100 in EY2021.

[79] The NPS is a metric of brand loyalty that measures how likely customers are to recommend a program to others. Respondents rate their likelihood to recommend the program on a 0 to 10 scale, where 0 means *not at all likely* and 10 means *extremely likely*. Respondents who give a rating of 9 or 10 are known as promoters, those who give a rating of 7 or 8 are known as passives, and those who give a rating of 0 to 6 are known as detractors. The NPS is expressed as a number between -100 and +100 that represents the difference between the percentage of promoters and the percentage of detractors (with passives excluded from the calculation).

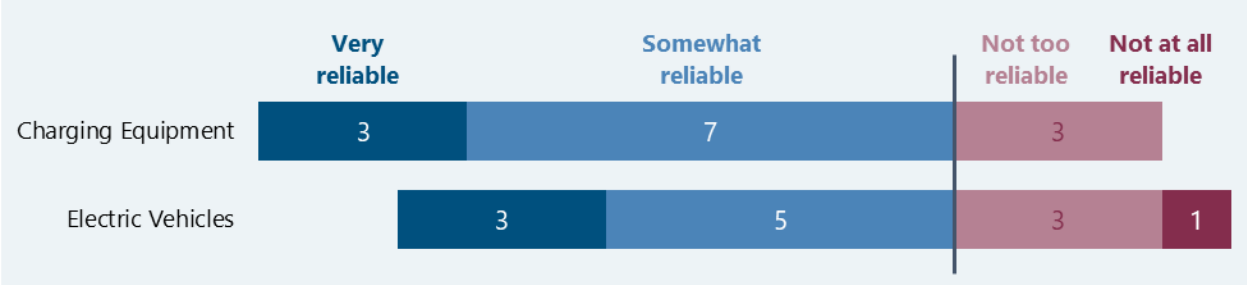
Program Awareness

The Evaluation Team asked fleet managers how they had learned about the EV Fleet program. Seven of 13 responding fleet managers said they had learned about the program directly from PG&E, four from an EV/EVSE manufacturer, and two from a contractor or engineer. PG&E staff were the top source of program awareness for fleet managers in EY2024 (6 of 11), EY2023 (2 of 4), EY2022 (4 of 6), and EY2021 (7 of 13). Ten of 14 fleet managers said that they were aware that they needed upgrades to the electrical infrastructure from the utility grid to their meter to charge EVs at their site, while four said they were not aware of this.

Experience with EVs and Charging Infrastructure

When asked to rate the ease of use of their EVSE, nearly all fleet managers reported that it was relatively easy to use. Six respondents reported that their charging equipment was *very easy* to use, six reported that it was *somewhat easy* to use, and one said that it was *not too easy* to use. When asked about equipment reliability, fleet managers reported finding their charging equipment to be more reliable than their EVs, with three rating their EVSE as *very reliable*, seven rating it as *somewhat reliable*, and three rating it as *not too reliable* (Figure 145). In contrast, three respondents rated their EVs as *very reliable*, five rated them as *somewhat reliable*, three rated them as *not too reliable*, and one rated them as *not at all reliable*. Fleet managers also cited challenges with their chargers' programming, screen and radio frequency identification reader issues, or chargers being unavailable. Fleet managers similarly reported high reliability in EY2021 through EY2024, although in EY2024 fleet managers responses indicated that their EVs were more reliable than the EV charging equipment.

Figure 145. PG&E EV Fleet Program Reliability of Vehicles and Charging Equipment in EY2025



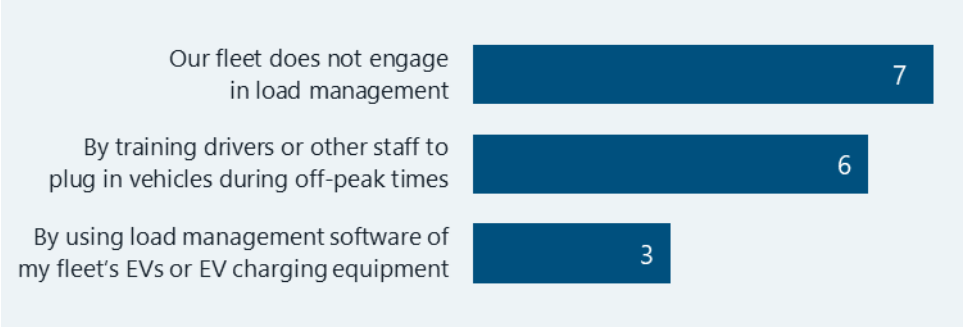
Source: Fleet Manager Survey Questions C3 and C4 "How would you rate the reliability of the EVs that are part of your fleet?" and "How would you rate the reliability of the EVSE?" (n=13)

Experience with Load Management and EV Charging

Asked whether they were aware that PG&E charges different electric rates per kilowatt-hour depending on the time of day, 11 of 13 fleet managers said that they knew this. Asked further whether they were aware of the cost to their company to charge their fleet, 11 of 13 fleet managers also said they were aware of the cost, and two said they were not. In EY2024, all 11 fleet manager respondents said that they knew that PG&E charged different rates depending on the time of day, and eight of 11 were aware of the cost of charging their fleet.

The Evaluation Team asked fleet managers whether they took any actions to ensure that they purchased the lowest-cost electricity for charging their fleet or, in other words, if they participate in load management. Of the 13 respondents, six reported that they did make use of load management, and seven said that they did not currently engage in any load management. This is a decrease from EY2024, when eight of 11 fleet managers reported using load management. As shown in Figure 146, the most common action taken for load management was training drivers or other staff to plug in their vehicles during off-peak times, reported by six fleet managers. Three fleet managers also said they used load management software included with their EVs or EV charging equipment.

Figure 146. PG&E EV Fleet Program Participant Load Management Practices



Source: Fleet Manager Survey Question C12 "What actions, if any, do you take to ensure you are purchasing the lowest cost electricity for charging fleet vehicles? A term you may have heard for this is load management" (n=13, multiple responses accepted)

The Evaluation Team asked the six fleet managers who practiced load management about their reasons for implementing the strategy. Five fleet managers reported that they implemented load management to lower the cost of charging and one to reduce the need to install additional power sources.

Of the seven fleet managers who did not practice load management, two said that their site had not been operational enough, one said that they do not have the capacity to put load management into place or manage the process, and one reported compatibility issues with software/chargers/vehicles. Another fleet manager said that their vehicles operate on shifts that require some to charge while others are operating and yet another said they didn't know enough about load management to practice it. In EY2024, fleet managers cited similar issues with compatibility, inflexible charging times, and lack of experience with EVs and charging as reasons for not having practiced load management yet. Asked if and how they planned to engage in load management, one fleet manager said that they planned to train drivers or other staff to plug in vehicles during off-peak times, two planned to use software to manage charging, and two still needed more information.

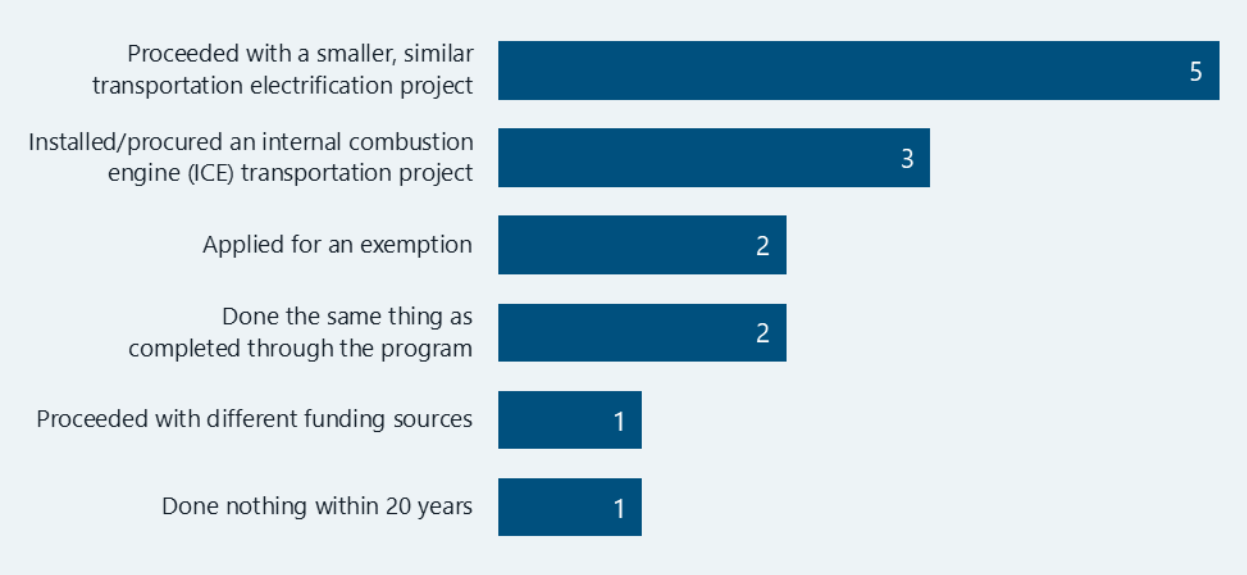
Impact of Program on Fleet Electrification

The Evaluation Team asked 14 fleet managers whether they planned to accelerate procurement of EVs and related equipment as a result of their experience with the EV Fleet program. Only one respondent said that they would accelerate procurement, four reported that they planned to slow procurement, and nine said they did not plan to change their procurement plans. Since EY2021, fleet managers have mostly maintained similarly stable EV procurement plans, with at least half of fleet managers each year saying

that they did not plan to change their procurement plans. Specifically, in EY2021 10 had no plans to change procurement, in EY2022 two of four had no plans to change, in EY2023 three of four had no plans to change, and in EY2024 eight of 11. In each year, no more than two fleet managers said they planned to accelerate or slow their procurement of EVs.

As shown in Figure 147 the Evaluation Team asked fleet managers what their electrification approach would have been if the PG&E EV Fleet program had not been available. Five of 14 fleet managers said they would have proceeded with a smaller, similar transportation electrification project, three said they would have proceeded with an ICE transportation project, and two each said they would have applied for an exemption or done the same thing as what they completed through the program.

Figure 147. PG&E EV Fleet Program Participant Actions if the Program Were Not Available



Source: Fleet Manager Survey Question G1 "If the PG&E fleet electrification program had not been available, which of the following alternatives would you organization most likely have done?" (n=14)

Twelve fleet managers surveyed reported their planned acquisition of EVs over the next five and 10 years, shown by market sector in Table 64.

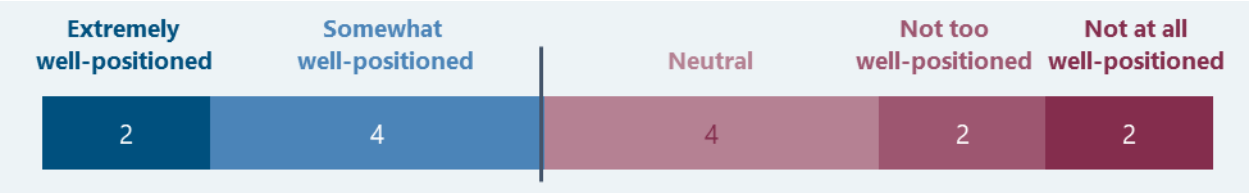
Table 64. PG&E EV Fleet Program EV Acquisition Projection by Vehicle Type in EY2025 (n=12)

Market Sector	Current Fleet Size		EV Projection	
	ICE	EVs	5 years	10 years
Medium-Duty Vehicle (n=8)	837	23	43	76
Heavy-Duty Vehicle (n=5)	273	23	10	23
School Bus (n=5)	52	31	1	3
Forklift (n=2)	22	4	0	0
Transit Bus (n=2)	26	45	10	25
Tractor (n=1)	2	1	1	1
Other (n=1)	20	6	3	6

Industry Perspective

The Evaluation Team asked how well-positioned fleet managers thought their industry or sector was for electrification. Two fleet managers said their industry was *extremely well-positioned*, four fleet managers said *somewhat well-positioned*, two said *not too well-positioned*, and two said *not at all well-positioned*, shown in Figure 148. Four others reported their industry's positioning for electrification as *neutral*. Of those who said their industry was not well-positioned, one cited a lack of charging infrastructure outside of their site and two said that EV fueling and maintenance cost was as expensive or more expensive to operate than ICE vehicles. Fleet managers in EY2025 were more optimistic about their industry positioning than in EY2024, when four of 10 fleet managers rated their industry as *not too well-positioned*, one as *somewhat well-positioned*, two as *extremely well-positioned*, and three as *neutral*. Fleet managers remain less optimistic about their industry positioning than in EY2023, when two rated their industry as *extremely well-positioned*, one as *somewhat well-positioned*, one as *neutral*, and none as *not well-positioned*.

Figure 148. PG&E EV Fleet Program Fleet Manager Positioning of Industry for Electrification in EY2025



Source: Fleet Manager Survey Question F1 "How well-positioned do you think your industry/sector is for electrification?" (n=14)

The Evaluation Team asked fleet managers what they saw as the limitations of current EV options for their market sector. Three respondents mentioned the mileage range of available EVs as a major limitation. Other respondents noted high costs and limited selection as limitations. Mileage range of EVs was a limitation commonly cited in EY2024 as well, mentioned by two of six fleet managers. Finally, fleet managers were asked whether electric or diesel trucks seemed like a riskier purchase in the next three years and the next 10 years, given their knowledge of current requirements or predictions of future requirements for fleets to purchase zero-emission MDHD trucks. For the three-year projection, 11 respondents said that electric trucks would be the riskier choice and three said diesel. For the 10-year projection, nine respondents said that electric trucks would be the riskier choice and four said diesel. In EY2024, similarly, six of 11 respondents said that EVs were riskier for the three-year projection and seven of 11 said that diesel vehicles were riskier for the 10-year projection.

Interview Results

The Evaluation Team interviewed eight fleet managers who had withdrawn from the PG&E program. Respondents included fleet managers for school districts, a waste management service, a regional water authority, retailers, and an EV charging infrastructure developer and operator that leases EVs to customers. As shown in Table 65, the total sizes of respondents' applied fleets ranged from a couple of vehicles to 80 vehicles and included heavy-duty vehicles, medium-duty vehicles, and school buses.

Table 65. PG&E EV Fleet Program Withdrawn Fleet Managers

Fleet Manager	Business Type	Applied Fleet Size
Respondent 1	Waste management	66
Respondent 2	Farm	5
Respondent 3	EV charging developer and EV leaser	50
Respondent 4	Generator retailer	2
Respondent 5	County water authority	3
Respondent 6	Online retailer	80
Respondent 7	School district	5
Respondent 8	School district	6

The Evaluation Team asked the fleet managers about their reasons for transitioning their fleets to EVs, why they stopped participating in the EV Fleet program and their overall satisfaction with the program. When asked why they had decided to electrify their fleets before they withdrew from the program, three fleet managers cited regulatory requirements as a main driver. Two fleet managers each said that incentives or environmental benefits were reasons for transitioning their fleet to EVs. One fleet manager, the charging infrastructure developer, said that electrification was central to their business model. The two other fleet managers were not sure about why their fleet decided to transition to EVs. In EY2024, the environmental benefits of EVs, the relative speed and quiet of EVs, and organization pressure to electrify were mentioned by fleet managers who withdrew from the program. No fleet managers cited regulatory requirements as their reason to transition to EVs in EY2024.

When asked about their main reasons for stopping participation, over half (five of eight) of fleet managers cited project cost. Two respondents said that they decided not to participate after the regulatory requirement was dropped. The remaining fleet manager cited limited grid capacity for the site, poor geography, and the risks of committing to EVs while the market is still not mature. Fleet managers also cited the following other reasons for leaving the program:

- The fleet manager for a waste management company explained that the higher weight of electric trash collection trucks would affect the amount of trash each truck could collect on a route because of legal weight limits on roads, which would require more trucks to accomplish what their current ICE fleet does. The fleet manager said that the cost of buying additional trucks, which each cost substantially more than the ICE alternatives, and the lack of space to house additional trucks made electrification a barrier they were unwilling to overcome without regulatory requirement.
- Worries about getting EVs serviced due to vehicle manufacturers going out of business, a higher likelihood of experiencing electrical bugs than with ICE vehicles, and challenges with sourcing parts (n=2).

The Evaluation Team asked fleet managers to rate their satisfaction with the program overall on scale of 1 to 4, where 1 is *not at all satisfied* and 4 is *very satisfied*. Four fleet managers said that they were *very satisfied* with the program despite having to withdraw, two were slightly less satisfied, giving the program ratings of 3 and 3.5, and one fleet manager said they were *not at all satisfied*. Of the seven fleet managers who had a positive experience with the program, all cited PG&E staff as being helpful, supportive, and

responsive to their questions as a reason for their satisfaction rating. Five of these fleet managers also said that their reasons for withdrawing from the program had more to do with outside factors than the program itself. Fleet managers who withdrew from the program in EY2024 similarly had broadly positive experiences with the program, highlighting good experiences working with PG&E staff.

The one fleet manager who was *not at all satisfied* with the program overall mentioned several reasons, including a lack of clarity around program equipment requirements and site fees, poor coordination among program staff, and a "pushy" salesperson from PG&E.

In addition, three fleet managers noted they were *not at all satisfied* with the level of incentives, with one saying that the rebates were so low they were "inconsequential" to this manager's decision-making. Fleet managers expressed similar dissatisfaction with the rebate amounts in EY2024, when two of four said they were *not too satisfied* or *not at all satisfied* with the rebate amounts.

After withdrawing from the EV Fleet program, six of eight fleet managers did not install any other EV charging equipment. The other two fleet managers, one whose business was developing EV charging sites and the other who installed chargers for a large retailer, continued to install EV charging on other sites, the latter continuing to participate in the program with the other sites.

Highlights

- Fleet managers were motivated to participate in the EV Fleet program primarily because of rebates/incentives for EV charging infrastructure (11), rebates/incentives for EVs (9), and environmental benefits (9).
- Top barriers to fleet electrification before program participation for fleet managers were the cost of EVs (9), the cost of installing EV charging infrastructure (8), and routes being too long (5). After program participation, all barriers became less significant.
- Most (12) fleet managers rated themselves as *very satisfied* or *somewhat satisfied* with their experience participating in the EV Fleet program.
- Ten fleet managers said that their EV charging equipment was very reliable or somewhat reliable while eight fleet managers said that their EVs were reliable or somewhat reliable.
- Six fleet managers reported that they practiced load management with their fleets.
- One fleet manager planned to accelerate EV and EV charging equipment procurement due to their experience with the program, while nine fleet managers did not plan on changing their procurement plans.
- Six fleet managers said they felt that their industry or sector was not well-positioned for electrification.
- Five fleet managers who withdrew from the EV Fleet program cited project cost being too high, and two withdrew because the regulatory requirement to electrify their fleet went away.

Site Visit Findings

In EY2025, the Evaluation Team completed 50 site visits in the PG&E territory across several market sectors: heavy-duty vehicle, medium-duty vehicle, school bus, transit bus, and forklift. During site visits,

the Team collected qualitative and quantitative information that provided the Team with an understanding of fleet composition and operations. We used site visits to verify aspects about sites such as the number of installed chargers, EVSPs the fleet uses, types of EVs in use or scheduled for delivery, and physical influences on construction designs.

Table 66 provides a summary of charging site characteristics by market sector, including the number of site locations visited in EY2025, number of ports, and total charging capacity. In total, the PG&E EV Fleet program added 1,268 ports with over 26 MW of EV charging capacity in EY2025. Eighteen medium-duty vehicle sites account for more than 14 MW, which is more than half of this capacity. This brings the total installed capacity to 92 MW in the program to date, an increase of 40% over the total capacity in the program to date by the end of EY2024.

Figure 149 is a visual representation of Table 66 showing charging port and charging capacity of the EV Fleet program sites the Evaluation Team visited by market sector for EY2025 and in the program to date. The reported installed capacity accounts for active charging ports installed on the Utility-provided TTM infrastructure, while the Utility SB 350 report refers to TTM installed capacity, which for some sites includes chargers that are not yet installed.

Table 66. PG&E EV Fleet Program Quantity of Ports and Installed Capacity, by Market Sector

Market Sector	EY2025 Sites	EY2025 Ports	EY2025 Capacity (kW)	PTD Sites	PTD Ports	PTD Capacity (kW)
TRU	0	0	0	1	16	160
Forklift	3	6	94	8	52	713
Heavy-Duty Vehicle	4	52	5,336	20	460	42,736
Medium-Duty Vehicle	18	958	14,396	48	1,669	25,475
School Bus	22	176	4,028	62	542	11,622
Transit Bus	3	76	2,751	16	200	11,911
Total	50	1,268	26,605	155	2,939	92,617

Figure 149. PG&E EV Fleet Program Site Visit Ports and Capacity, EY2025 and PTD Sites

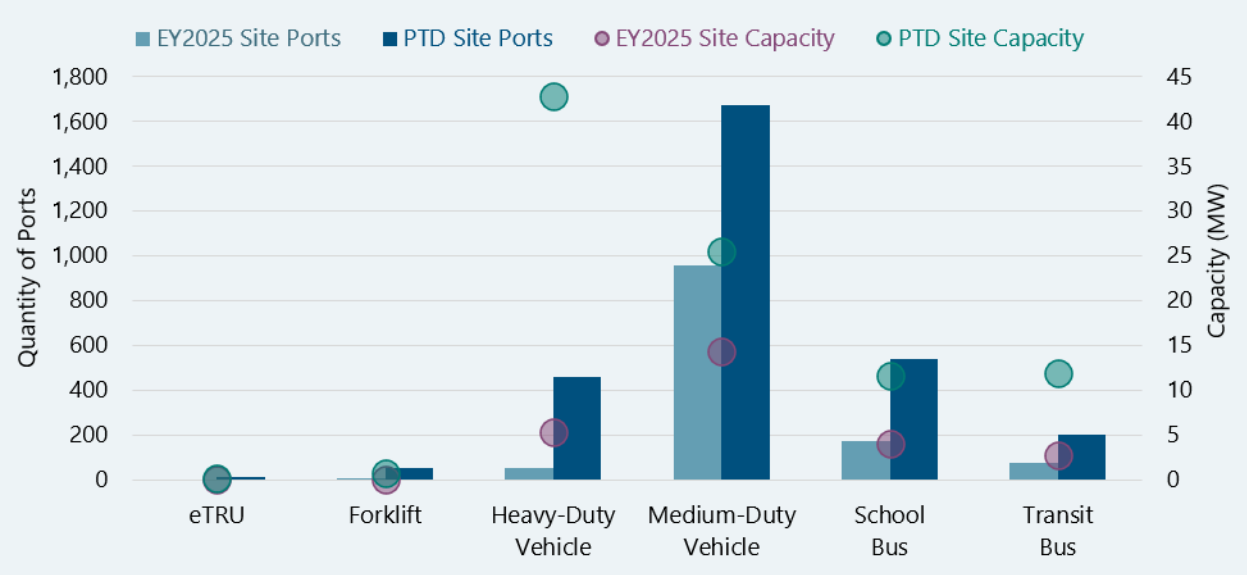
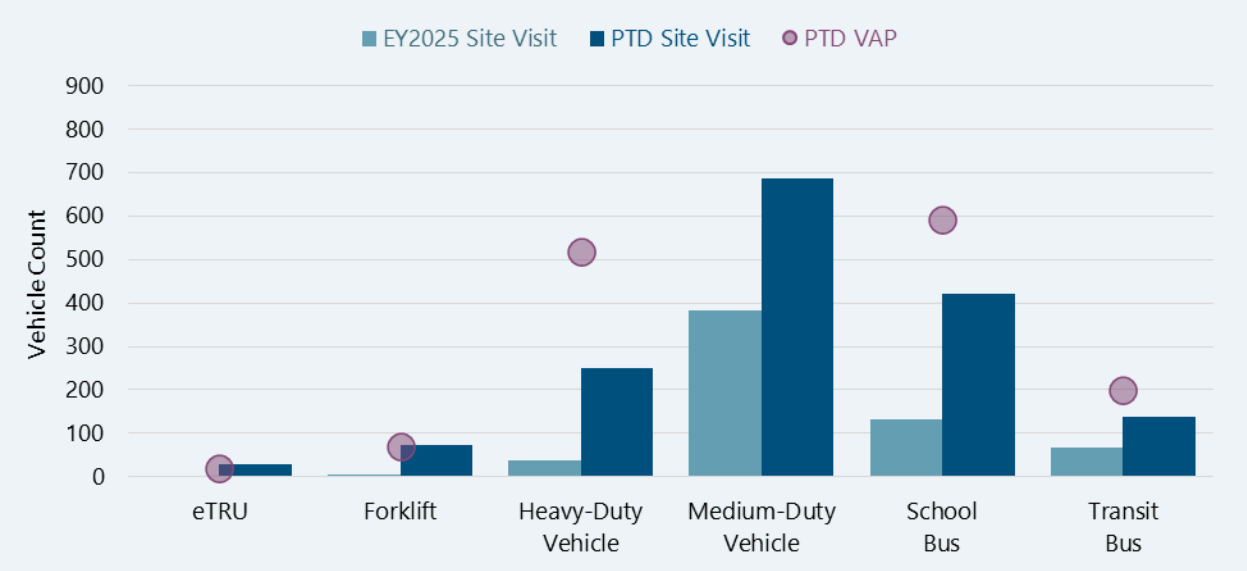


Figure 150 shows the count of vehicles noted through site visits compared with the number on fleets' five-year VAPs. Sites the Team visited with vehicles in the TRU and forklift market sectors have all fulfilled their VAPs. Sites visited with vehicles in the transit bus and school bus market sectors are both at 70% of VAP, while sites with vehicles in the heavy-duty vehicle and medium-duty vehicle market sectors are both below 50% of VAP. In general, the Team expects differences between observed vehicles and total vehicles included in long-term VAPs, as the Evaluation Team visits each site only once and does not update the count of vehicles for sites activated in previous years.

Figure 150. PG&E EV Fleet Program Comparison of Verified Vehicles to Long-Term VAP



During site visits, the Evaluation Team reviewed charge management capabilities and electrical infrastructure, discussed future vehicle/equipment replacement plans (including vehicle adoption) and public funding sources, and investigated whether fleets had an interest in on-site solar and battery storage. Site visits allowed the Team to obtain direct feedback from the individuals involved with operations and to identify EVSP points of contact to obtain charging session data.

The following sections provide a summary of key observations and data collected during site visits.

Common Site Visit Findings Across Utility Programs

Like in EY2024, the Evaluation Team continued to see sites that supported multiple fleets, including large truck stop–type sites, vehicle dealer sites, and other sites that offer public charging.

Dealerships continued to participate in SB 350 programs across the state, with some constructing multiple sites. Dealerships offer charging to dealer-operated and rental vehicles, and some make the site available to neighboring fleets. Several operators of other types of fleets also participated in one or more Utility programs to construct multiple sites. Most of these fleets replicated the same infrastructure from site to site, while others modified the site design based on regional demand.

Fleets across all market sectors continued to express concerns over the long-term viability of vehicle OEMs, NSPs, and EVSE manufacturers.

Many fleet managers reported that they do not know how much they spend on utility bills for charging EVs or how these costs compare with the costs of using conventional fuels. They were also not sure whether reducing the cost of charging would be possible. Some of these fleets participated in a deep dive interview that examined the barriers to fleets implementing load management, which would allow them to shift some of their EV charging to periods of low-cost electricity. A summary of these interviews is presented in the *Statewide* section of this report.

School Bus

The Evaluation Team visited 22 of the 26 activated school bus sites in EY2025. The school bus market sector continues to lead the other sectors in the number of sites activated in PG&E's EV Fleet program, with 68 of 170 total sites in the program (40%). The 62 school bus sites the Team visited in the program to date were in aggregate meeting more than 70% of their VAP at the time of the site visits. Across sites, fleet managers regularly mention bus reliability as an issue, with manufacturers providing varying levels of service.

School bus site staff reported several positive experiences with vehicles, chargers, and NSPs:

- Many sites are combining L2 (16.5 kW) chargers with high-power 30 kW to 60 kW DCFCs, as shown in Figure 151. This gives the schools flexibility to top off vehicles that need more charge to run an afternoon route or accommodate after-school activities.
- Most of the sites reported good experiences with their contractors and NSPs. Many sites have ordered their charging equipment through their bus dealer, simplifying the order process.

- A few sites had operated electric school buses for multiple years and used the EV Fleet program to upgrade and expand their charging infrastructure to support more EVs.
- Some fleet managers stated that they had received good support from their NSP to set up load management within the first few months of vehicle and charger commissioning.

Figure 151. PG&E EV Fleet Program School Bus Site with DCFC (left) and L2 (right) Charging



School bus site staff also reported several challenges they had experienced:

- Two sites installed V2G-capable chargers from a major manufacturer that decided to exit the EV charging market. These chargers were purchased and installed but had not been commissioned before that exit, leaving both sites with chargers that could never be used. One site immediately replaced these chargers with temporary chargers to serve vehicles. The other site had installed non-V2G chargers that could be used while the site worked on a resolution for the unusable equipment.
- Some site staff reported that the site's NSP was hard to reach and not helpful in setting up fleet charging schedules.
- Multiple sites experienced delays in the delivery of new vehicles, which led to infrastructure that was unused for many months. One school had to change its bus order after the original manufacturer could not deliver the vehicles, leading to a delay greater than one year.
- Some newly delivered vehicles had quality control issues, such as seats that were not bolted down correctly, or wiring harnesses that came loose in the first weeks of use. Some vehicles had to be repeatedly towed to a dealer or were otherwise out of service for extended periods of time.

- One school has begun to acquire parts from online auction platforms to help keep vehicles from a bankrupt manufacturer in service. The fleet technicians have more flexibility to repair these older vehicles, as new vehicles under warranty must be serviced at a dealership or by OEM-trained technicians.
- School district personnel continue to voice concerns about using their vehicles for field trips and sports events. Limited battery capacity and charging capacity with L2 chargers could be a bottleneck for activities beyond regular routes.

Transit Bus

The Evaluation Team visited three of the six transit bus sites that were activated in EY2025. All three sites installed 60 kW to 80 kW DCFCs, and one also installed L2 chargers for the fleet's paratransit shuttle vans. A transit agency in Central Valley secured more than $20 million in funding to electrify five 30-foot transit buses and 25 paratransit shuttle vans. To charge its transit fleet the agency installed two 80 kW DCFC, 29 L2 chargers, and a 250 kW induction charger along with 1.2 MW of solar, 1 MWh of battery energy storage, and a diesel generator for resiliency (Figure 152).

Figure 152. PG&E EV Fleet Program Transit Agency Charging Site with Solar and Energy Storage



Transit bus sites showed a wide range of readiness and operational maturity. Two agencies have developed large, well-planned systems with diverse fleets and multiple charger types and show emerging use of load management to improve performance. These more advanced sites demonstrate thoughtful planning, including diversifying vehicle makes and building infrastructure at scale to support long-term electrification. One site used European-made electric minibuses in addition to full-size transit buses. Staff from another site noted the limited availability of electric paratransit vehicles.

At the same time, two transit sites were still early in deployment or not yet operational, with chargers installed but vehicles not yet in service or with infrastructure only partially complete. Two agencies are also integrating or planning for solar and battery storage (Figure 153), both for resilience and to keep the cost of electricity low. All agencies used a combination of federal, state, and local funding to pay for the energy infrastructure and the vehicles.

Figure 153. PG&E EV Fleet Program In-Progress Transit Charging Site with Solar Canopy



One agency representing two sites that the Evaluation Team did not visit shared in a virtual interview that these sites had built infrastructure capacity in earlier pilot phases to support future charger installations, which were installed in EY2025. Overall, the transit bus market sector reflects both strong forward planning and common implementation delays typical of large transit electrification projects, both across Utility MDHD programs and nationally.

Medium-Duty Vehicle

The Team visited all 18 medium-duty vehicle sites activated in EY2025. These sites spanned a wide range of use cases, fleet sizes, and levels of operational maturity, so our findings are difficult to generalize. In one case, a single customer accounted for four sites hosting 675 chargers and nearly 9 MW of installed charging capacity to support 858 vehicles.

Medium-duty vehicle sites are often less mature than other sites in terms of charging optimization and energy management practices, especially compared with sites that have heavy-duty vehicle fleets operated by large multistate companies. With most sites functioning as mixed-use facilities for unique or niche operators with varying charging behaviors, many were not managing their charging. Several sites, especially dealerships showed low utilization. Overall, the medium-duty vehicle market sector is in a transitional and uneven stage of electrification. These delivery fleets saw some large deployments of both vehicles and charging infrastructure, and their utilitization will continue to grow as they fulfill their VAPs.

Large medium-duty delivery fleet sites often include multiple rows of charging equipment, each with its own service panel, serving 10 to 20 charging positions at a time (Figure 154).

Figure 154. PG&E EV Fleet Program Medium-Duty Vehicle Delivery Site Vehicles and Infrastructure



One key observation for medium-duty vehicle sites in the program to date is that operations vary considerably between large, standardized fleets and smaller fleets with niche operations. Large fleet operators often have significant vehicle counts (sometimes in the hundreds), while many other medium-duty vehicle sites consist of small fleets with only a handful of vehicles (often five to 10 and sometimes fewer). In addition, certain medium-duty vehicle sites such as vehicle dealerships (e.g., truck centers and car dealers) tend to have low charger utilization, with their infrastructure often used intermittently for service vehicles or customer charging rather than for daily fleet operations. This leads to low energy throughput, which reduces the site's ability to achieve cost efficiency. Many public agencies are installing infrastructure and purchasing vehicles to meet the ACF regulations, including trucks and vans serving police, parking enforcement, and public works (Figure 155). However, the discontinuation of the Ford F150 Lightning and limited availability of Class 3 and 4 work trucks may slow growth in utilization of this infrastructure. One municipality planned to make some of their charging facilities available to the public until it acquired more fleet vehicles.

Figure 155. PG&E EV Fleet Program Police Service Medium-Duty Trucks



A city site in the Bay Area illustrates a complex, multiuse municipal electrification approach that spans several vehicle classes and charging systems. The city operates a diverse fleet including garbage trucks, dump trucks, pickup trucks, and shuttle vans, supported by a mix of charging infrastructure both within and outside the PG&E EV Fleet program.

One key finding is that the city currently has significantly more charging infrastructure than active utilization. However, this makes the city prepared for future growth as funding for additional vehicles becomes available. The site also integrates solar generation through a power purchase agreement (PPA), but is underutilizing that load, prompting efforts to shift certain vehicles such as refuse collection trucks to charge on non-program meters to take advantage of excess solar capacity. This ensures that the city is maximizing the financial and emissions reduction benefits of the solar generation but also reduces the benefits attributed to the PG&E EV Fleet program. Overall, this city represents an early-stage municipal model prepared for more growth, in which multiple funding streams, vehicle types, and charging assets are being coordinated, even as operations, optimization, and utilization are still evolving.

Heavy-Duty Vehicles

The Evaluation Team visited all four heavy-duty vehicle sites activated in EY2025. Two sites were from a nationwide company operating Class 8 refuse collection trucks, and two were operating Class 8 tractors as shown in Figure 156. All four sites installed several 120 kW or 180 kW dual-port DCFCs, and two large sites showed 2 MW of charging capacity. One distinct theme across heavy-duty vehicle sites, particularly with Class 8 fleet operators, is that they are generally more advanced in their load management implementation and have higher power charging infrastructure than sites in other market sectors. Three of the four sites demonstrated strong load management (less than 15% of energy use between 4 p.m. and 9 p.m.), with the fourth site planning to use load management in 2026 after only one month of use in 2025. All four sites have implemented or plan to implement effective load management and charging software through experienced NSPs. One operator installed a large battery system to help offset on-peak demand in anticipation of pairing with solar generation.

Despite the implementation of load management and distributed energy resources like solar and energy storage, several fleet managers expressed concerns about higher-than-expected electricity bills and weaker cost savings compared with diesel fueling of their fleet than they had originally anticipated. Reliability issues (such as trucks frequently being out of service) further compounded these challenges.

Figure 156. PG&E EV Fleet Program Heavy-Duty Truck Charging



Forklifts

The Evaluation Team visited all three forklift sites activated in EY2025. Two sites were implemented by a company that moves building materials in a warehouse and around the yard (shown in Figure 157), and the third site was in an agricultural setting. The warehouse sites were able to electrify using local air district grants to remove older internal combustion–powered forklifts. Although the new equipment was an adequate replacement for the former propane-powered forklifts, the fleet manager was concerned that the vehicles might not have enough battery capacity to last all day on a busy day or be able to charge during a power outage. The fleet manager did not plan to electrify larger diesel-powered forklifts in the yard, as they didn't think any available equipment could meet the site's duty-cycle for a reasonable cost. The electrical equipment was not sized for future expansion but could accommodate one additional lower-power charger (less than 15 kW). The chargers functioned well, according to the fleet manager who also said they had not set up timers to limit the charging to the lowest cost time periods.

The agricultural site had only recently become operational at the time of the site visit, and therefore had limited operational experience. In addition, the vehicle manufacturer had declared bankruptcy, causing concern about long-term vehicle reliability without manufacturer support.

Figure 157. PG&E EV Fleet Program Forklifts



Highlights

- The PG&E EV Fleet program sites visited by the Team added 1,268 ports with over 26 MW of EV charging capacity in EY2025, bringing the total installed capacity to over 92 MW in the program to date.
- Eighteen medium-duty vehicle sites the Team visited in EY2025 account for more than 14 MW of charging capacity (more than half of the capacity of the 51 sites the Team visited in EY2025), with a single customer with four sites and 675 chargers accounting for nearly 9 MW of installed charging capacity to support 858 vehicles.
- The heavy-duty vehicle market sector, which includes refuse collection trucks, semi-trucks, and yard tractors, continues to grow and has been generally more advanced in their load management implementation.
- Medium-duty vehicle sites include large delivery sites with more than 100 ports installed as well as municipal and dealership sites that show low usage.
- Two school bus sites had installed V2G-capable chargers that were rendered inoperable when the manufacturer exited the market.
- Transit districts are continuing to electrify both full-size and small transit vehicles. Some agencies are also deploying solar to help offset the cost of electricity, although these sites take a long time to become fully operational.
- Some heavy-duty vehicle sites show a vehicle-to-charger ratio higher than one to one. One site participated in the Flex Connect pilot and installed battery storage to overcome grid constraints.
- Fleet managers continued to report EV reliability issues and range limitations.

Deep Dives

The Evaluation Team conducted deep dives in EY2025 for two fleets operating in PG&E territory. The Team considered sites with significant demand, energy consumption, or installed charging capacity; sites that had an ability to expand EV infrastructure; sites with load management, unique vehicles or charging equipment, a large fleet; and importantly, sites with a fleet manager who was willing to participate in the deep dive process.

The two PG&E EV Fleet program sites the Team examined consisted of one Class 8 heavy freight fleet operator and one delivery company. The Evaluation Team conducted in-depth fleet manager interviews and analyzed data from AMI and EVSPs. During interviews, the Team requested permission to survey drivers; however, none of the sites administered the surveys.

Findings presented in this section are based on interviews and data analysis. *Appendix A* presents more detailed case studies on each of these fleets.

Fleet 1: Heavy-Duty Freight Operator

The Evaluation Team selected a heavy-duty freight operator, operating Class 8 trucks, for a deep dive analysis because the fleet's site features two phases of installed solar photovoltaic (PV) panels totaling more than 5 MW and a 2.7 MWh battery energy storage system (BESS). While the site used the PG&E grid connections provided through the EV Fleet program, the solar PV and BESS both impact overall site

operations. The fleet also operates three sites in SCE territory, which are covered in the SCE *Deep Dives* section.

The site's EV Fleet program chargers consist of 16 dual-port, 360 kW Charge America/PhiHong DCFCs, functioning on Ampcontrol software. Like the other sites under this operator's control, these chargers are accessible by both the operator's fleet and the general public. Unlike the other sites, at the time of a site visit in early 2025, this site also operated 15 single-port, 240 kW DCFCs and three prototype 1.2 MW chargers built specifically for the fleet, which were not funded by the EV Fleet program. These additional chargers are tied into the solar PV and BESS, while the EV Fleet chargers are tied directly to the grid.

The fleet operates a diverse set of vehicles, which move between the EV Fleet site and ancillary sites based on need and duty cycles and charge based on opportunity and availability. The EV Fleet program directly supports 48 battery-electric Class 8 tractor-trailers—a mix of Nikola, BYD, Volvo, and Tesla models—but the fleet operates a total of 75 vehicles across all of its sites in California. The fleet manager estimates that these 75 EVs drive around 100,000 miles per week, necessitating quick, reliable charging with available redundancy.

The fleet manager noted that their charging policy has shifted from trying to avoid charging during the 4 p.m. to 9 p.m. period, in favor of a "charge when needed" approach that prioritizes operational efficiency. The EV Fleet chargers are grid-tied and have been used mostly outside of the 4 p.m. to 9 p.m. period over the course of the site's lifetime, though the chargers demonstrate a reliable uptick in usage beginning around 3 p.m. and peaking at 5 p.m. From project inception to December 31, 2025, the peak recorded demand was 1.1 MW; on average, demand peaks at around 6 a.m. at 130 kW. During the day, the site prioritizes using the charging stations tied to the BESS, which offers three critical benefits: the ability to leverage its megawatt-capable charging stations; the ability to avoid expensive demand charges; and the avoidance of the higher energy rates typical of the 4 p.m. to 9 p.m. period. As a result, the off-grid charging is generally utilized more than the on-grid installation, leveraging the significant PV generation to operate the charging stations during daylight hours. The fleet manager estimated that overall, the BESS installation is sized to cover roughly 30% of the site's daily charging needs and serves mostly as a 'soft landing' transitioning from PV-supported charging to grid-tied charging, which further reduces the amount of peak-rate energy the site uses.

The fleet manager expressed satisfaction with their diverse set of vehicles, noting that reliability has been broadly good and that any issues that arise are quickly resolved by their vehicles' manufacturers. The fleet has actively built out an internal engineering team to allow for the maintenance and repair of one specific model of EVs, manufactured by a company that is no longer operational, without having to involve a third party.

Fleet 2: Medium-Duty Delivery Operator

The Evaluation Team selected a medium-duty logistic site because of the fleet's operation of around 50 electrified sites throughout California, with five EV Fleet sites operational in PG&E territory. The fleet also operates a site in SDG&E territory and is covered in the *Deep Dives* section in the SDG&E chapter.

Plans are in place for the operator to continue building out infrastructure and upgrading sites with more network capability, and to standardize equipment and implement network providers across all of its sites.

As of December 31, 2025, the operator had 52 BrightDrop electric delivery vans across their sites in PG&E territory, generally operating between 45 to 100 miles per day. Vehicle operations are similar to those observed at the site in SDG&E territory, vehicles averaged 100 miles a day and occasionally approached 150 miles on particularly heavy days. The sites originally expected to receive EVs from another manufacturer that ceased operation in 2021, forcing the fleet to change its sourcing plans. However, at many of the sites, chargers had been procured and installed by this manufacturer.

Across its five sites in PG&E territory, the fleet operates 39 dual-port DCFCs each with a capacity of 30 kW, from one manufacturer, and 58 L2 stations each with a capacity of 16.5 kW manufactured by a different company. One of the sites has seen little operation since August 2025, and may be decommissioned, with its EVs potentially transferred to another site.

The operator gave their DCFCs high marks for functionality and reliability and cited the manufacturer's involvement and communication as key components of the chargers' uptime. While the fleet manager did not note any particular issues with their BrightDrop vans, GM has discontinued production of these vehicles, and the fleet is currently engaged in conversations with other manufacturers to source battery-electric vans moving forward.

Highlights

- The medium-duty delivery fleet operator found that their EV ranges were more than enough to serve all regular routes. The other Class 8 operator reported looking forward to acquiring longer-range trucks and megawatt chargers to enable longer routes.
- None of the fleets the Team visited had implemented charge management to avoid charging during the highest-cost energy periods during their initial deployments. However, the fleet managers are now exploring opportunities to save money by minimizing charging during the 4 p.m. to 9 p.m. peak period.

Co-Benefits and Co-Costs

Through fleet manager surveys, deep dive fleet manager interviews, and site visits, the Evaluation Team explored several co-benefits and co-costs associated with the PG&E EV Fleet program's vehicle electrification sites.

Fleet Manager Surveys

To assess co-benefits and co-costs, the fleet manager surveys used both aided (asking fleet managers if they expected a specific co-benefit or co-cost) and unaided (open-ended) questions.

For EY2025, 13 fleet managers completed the fleet manager survey. Table 67 shows that all 13 responding fleet managers expected to realize at least one type of benefit for their community or fleet from electrifying. Fleet managers expected benefits to the community to be more significant than those to their fleets. For instance, five fleet managers expected significant benefits from improved air quality and health

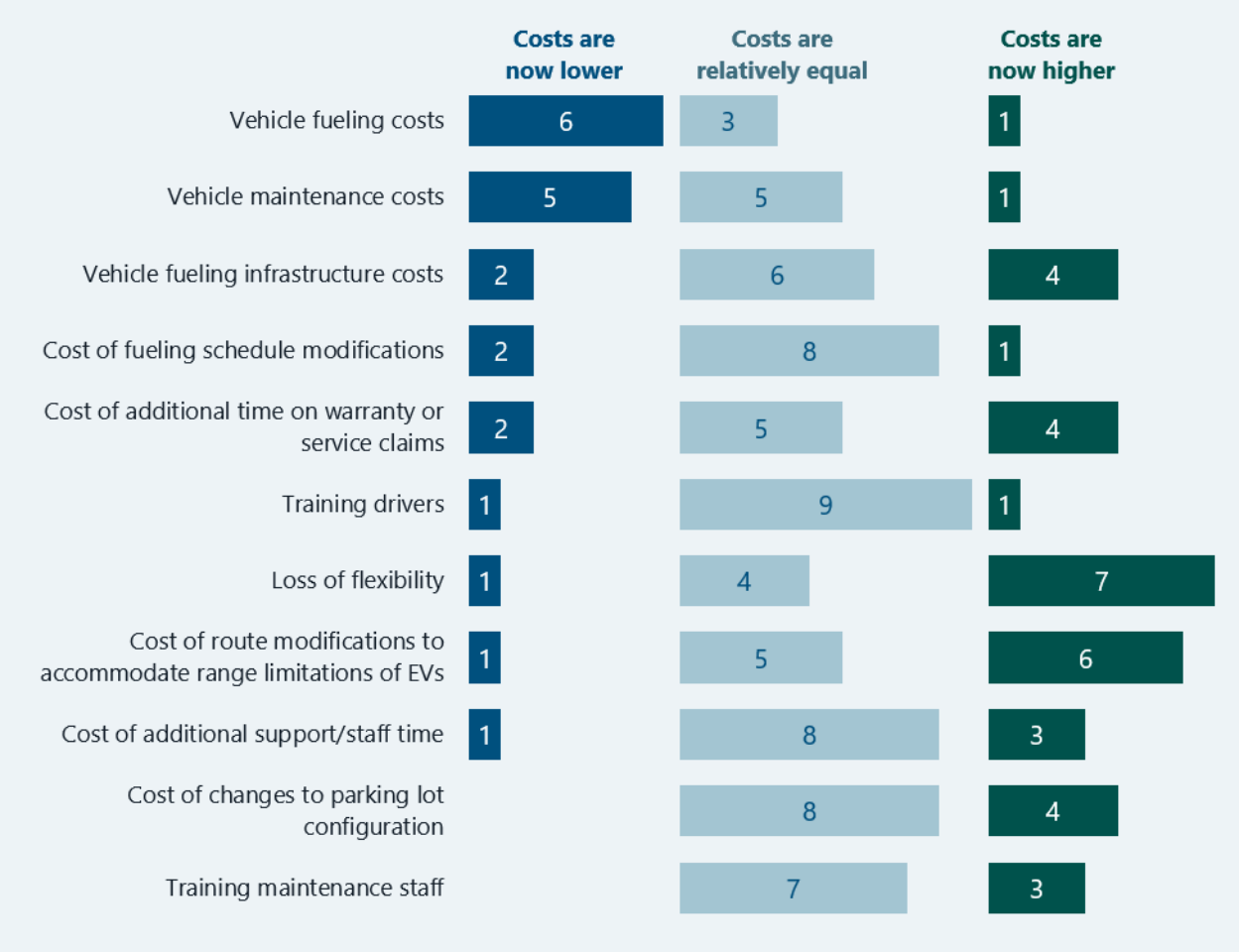
and four expected significant benefits from reduction in noise pollution. In contrast, eight of the 13 fleet managers expected no benefits from increased fleet flexibility. Still, many fleet managers expected some benefits to drivers and other fleets more broadly, with nine expecting some benefits from encouraging other individuals or fleets to convert to EVs and improved driver/passenger comfort/convenience. These results are mostly consistent with previous results, when nine of 13 fleet managers in EY2021, one of five in EY2022, and three of four in EY2023 expected significant benefits from both improved air quality and health and reduced noise pollution. In EY2024, eight of 10 expected significant benefits from improved air quality and health and seven of 10 expected significant benefits from reduced noise pollution.

Table 67. PG&E EV Fleet Program Benefits Fleet Managers Reported from Electrification in EY2025

Benefits	Significant Benefits	Some Benefits	No Benefits
Encourages other individuals or fleets to convert to EVs	1	9	3
Improved air quality	5	7	1
Reduction in noise pollution	4	8	1
Improved driver/passenger comfort/convenience	2	9	2
Increased fleet flexibility	1	4	6

The Evaluation Team asked fleet managers to estimate how the costs associated with operating and maintaining their fleets have changed since electrification. As shown in Figure 158, six of 12 fleet managers reported lower costs for vehicle fueling and five of 12 observed lower vehicle maintenance costs. Seven of 12 fleet managers cited higher costs for the loss of flexibility of their new vehicles, and six of 12 fleet managers cited higher costs for the cost of route modifications to accommodate range limitations of the EVs. Many fleet managers estimated that their costs remained relatively equal across cost categories, as most fleet managers have reported since EY2021. These results are largely consistent with results in EY2024, when fleet managers also saw lower costs for vehicle fueling and vehicle maintenance and higher costs for loss of flexibility and route modifications than the other cost categories.

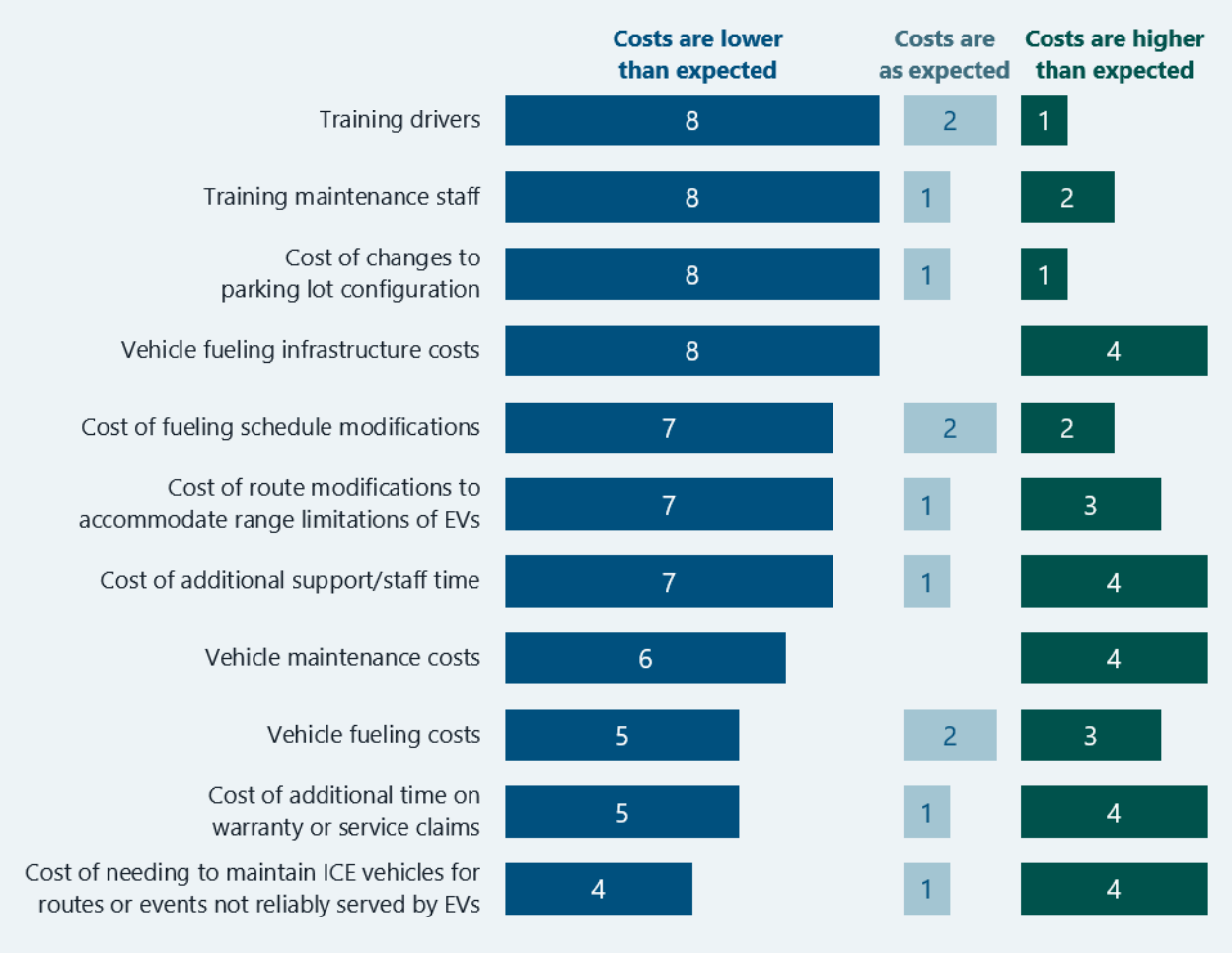
Figure 158. PG&E EV Fleet Program Observed Cost Changes since Electrification in EY2025



Source: Fleet Manager Survey Question E1. "Please think about all the costs associated with operating and maintaining your fleet. For each cost type shown below, please estimate how much the cost has changed since transitioning your fleet to EVs." (n=12)

The Evaluation Team asked fleet managers to what extent they expected operational and maintenance costs to change. As shown in Figure 159, costs were lower than expected for most fleet managers across nearly all categories. Eight of 12 fleet managers observed lower-than-expected costs for training drivers, training maintenance staff, changes to parking lot configuration, and vehicle fueling infrastructure. Only four of 12 fleet managers observed higher-than-expected costs for vehicle fueling infrastructure, additional support/staff time, vehicle maintenance, additional time on warranty or service claims, and maintaining ICE vehicles for routes or events not reliably served by EVs. Results differed substantially from results in EY2024, when no more than two of 11 fleet managers observed lower-than-expected costs in any category. In EY2021, EY2022, and EY2023, most fleet managers reported that costs were as expected. One fleet manager mentioned that another cost they incurred as a result of electrifying was for taking vehicles to the dealer for programming and updating.

Figure 159. PG&E EV Fleet Program Differences between Electrification Expectations and Costs in EY2025



Source: Fleet Manager Survey Question E2. "Have these operational and maintenance costs been what you expected?" (n=12)

Deep Dive Fleet Manager Interviews

The Evaluation Team conducted Deep Dive interviews with two fleet managers with sites in PG&E territory to assess the co-costs and co-benefits of transportation electrification for fleets and fleet drivers. During the interviews, fleet managers noted several costs and benefits:

- **EV Range and Charging Duration.** One of the two fleet managers said that their EVs generally have enough range to make it through most of their shifts. However, the other fleet manager was looking forward to the delivery of longer-range vehicles, as well as MCS-capable chargers, that would support long-distance routes between charging hubs, which would allow them to avoid the current return-to-base arrangement.
- **Charge Management Capability.** One of the two fleet managers reported looking for a new NSP and possibly new charging equipment that would allow them to better manage charging to avoid the highest-cost time periods. Another fleet manager mentioned looking for ways to reduce

charging costs after spending the first year of deployment concentrating on vehicle operations. All fleet managers saw cost benefits of electricity over diesel but needed to focus on making sure their fleets were maximizing those benefits.

- **Unsubsidized Costs.** Both fleets received public grants such as air district or CEC grants for vehicles and infrastructure but still had out-of-pocket expenses. However, the grants helped mitigate risks for the sites and allowed the fleets to pilot electrification. Both fleet managers reported that they hoped to use lessons learned from participating in the EV Fleet program to deploy future sites that are less reliant on subsidies to achieve cost-effectiveness.

Despite some of these initial cost challenges, both managers conveyed overall positive experiences with their electrified fleets and were planning more vehicle electrification in the future.

Highlights

- All 13 responding fleet managers anticipated benefits for their community or fleet because of electrification.
- Five of the 13 fleet managers expected significant benefits from electrification from improved air quality, and four of 13 expected significant benefits from reduced noise pollution.
- Six of 12 fleet managers said costs of vehicle fueling were lower after electrifying, and seven of 12 observed higher costs from the loss of fleet flexibility.
- Eight of 12 fleet managers saw lower-than-expected costs for training drivers, training maintenance staff, changes to parking lot configuration, and vehicle fueling infrastructure.
- Both deep dive interviewees noted challenges around EV range and charging duration, load management, and out-of-pocket costs.
- Both deep dive interviewees conveyed an overall positive experience with their electrified fleets and said that their organizations are planning additional deployment in the future.

Site Costs

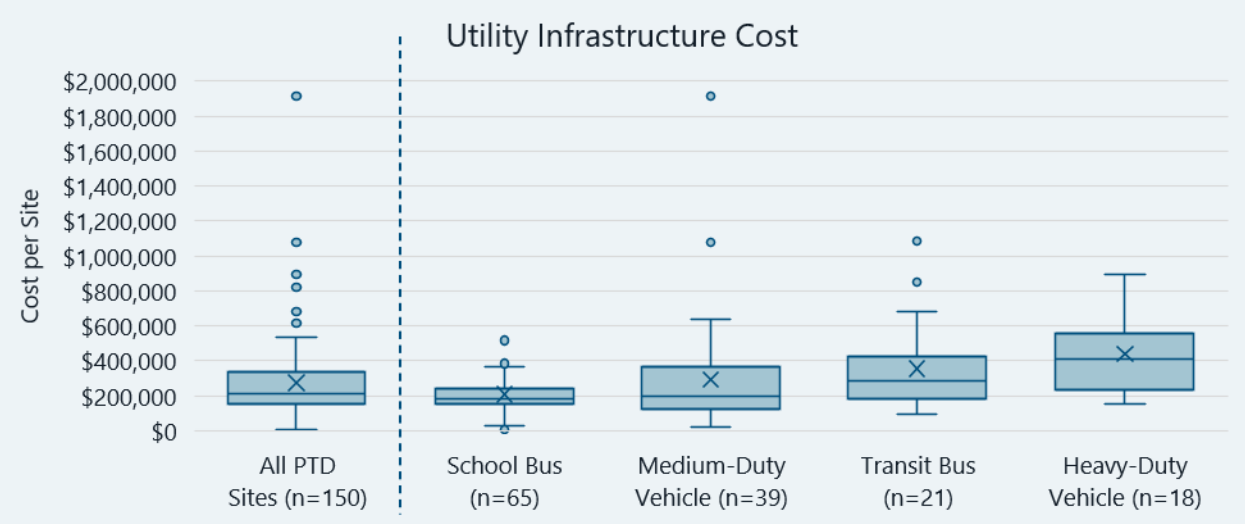
The Evaluation Team conducted a cost analysis on 150 sites with fully closed out finances as of December 31, 2025. The set of fully closed out sites is smaller than the set of activated sites because of the time lag involved in performing activities such as collecting receipts, paying invoices, and obtaining administrative approvals.

Sites had a mix of L2 and DCFC ports, with an average of 660 kW of installed capacity and 19.6 ports program to date. The 150 sites included 65 school bus sites, 39 medium-duty vehicle sites, 21 transit bus sites, 18 heavy-duty vehicle sites, six forklift sites, and one TRU site. The Team aggregated findings across all market sectors to meet customer confidentiality requirements. Only six of 150 closed out sites are Utility-constructed BTM infrastructure. The other 144 sites are site-owner installed BTM infrastructure.

Figure 160 shows the distribution of site-level costs of the 150 sites between 65 school bus and 85 non-school bus sites. The horizontal lines of the boxes show the 25th, 50th, and 75th percentile of sites; the X denotes the mean site cost; and the three panels are defined as follows:

- **Utility Infrastructure Costs.** Actual site installation costs borne by the Utility for both TTM and BTM (or the BTM incentive when the site infrastructure is customer-owned), including all capital and labor costs.[80] This does not include the cost of the EVSE equipment or installation.
- **Ratepayer-Funded Costs.** Actual site installation costs borne by the Utility, including all capital and labor costs of TTM, BTM (or the BTM incentive if the site infrastructure is customer-owned infrastructure), and EVSE rebate.
- **Estimated All-In Costs.** Estimated costs of installing the site borne by the Utility and the customer including all capital and labor costs. The value is calculated by summing actual TTM,[81] actual or estimated BTM,[82] and estimated EVSE costs.[83]

Figure 160. PG&E EV Fleet Program Per-Site Costs Organized by Three Perspectives, Across 150 Closed-out PTD Sites

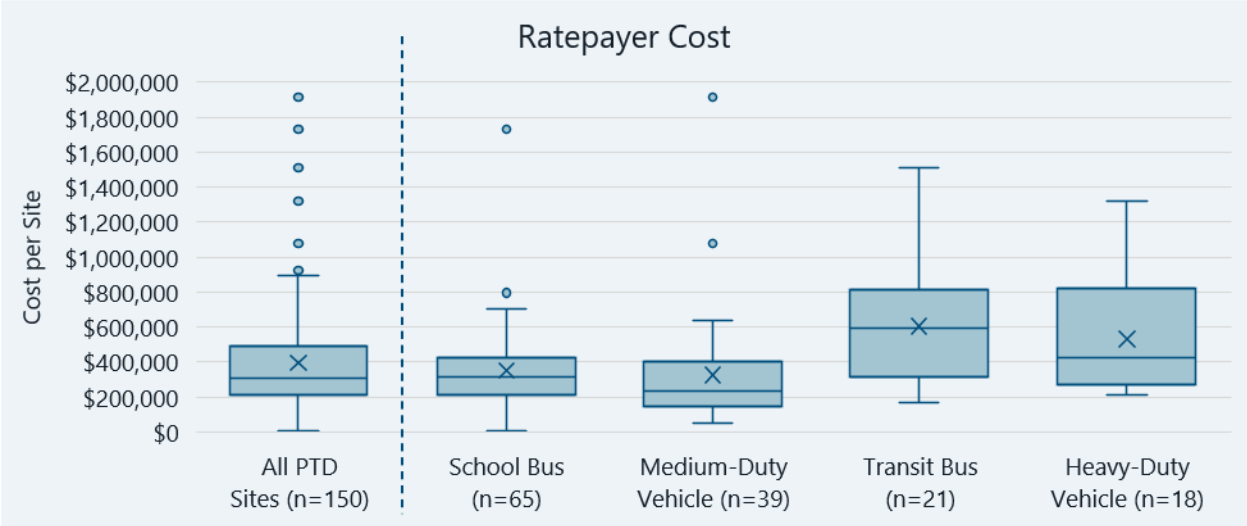


80 Utility Infrastructure costs are the same as the Ratepayer-Funded Costs, except they do not include the EVSE rebates.

81 The Utility pays 100% of the TTM costs and therefore reports actual TTM costs to the Evaluation Team.

82 The Evaluation Team receives actual BTM costs for sites with Utility-owned BTM. In total, six of 150 sites with fully closed out financials have Utility-owned BTM. Other BTM costs were estimated by the Evaluation Team using the relationship between installed kilowatts and BTM from other sites with actual BTM costs.

83 Because the Utility does not record actual EVSE costs, the Evaluation Team estimates all-in EVSE equipment costs using assumptions of $3,000 per port for L2 ports and $45,000 per port for DCFC ports.



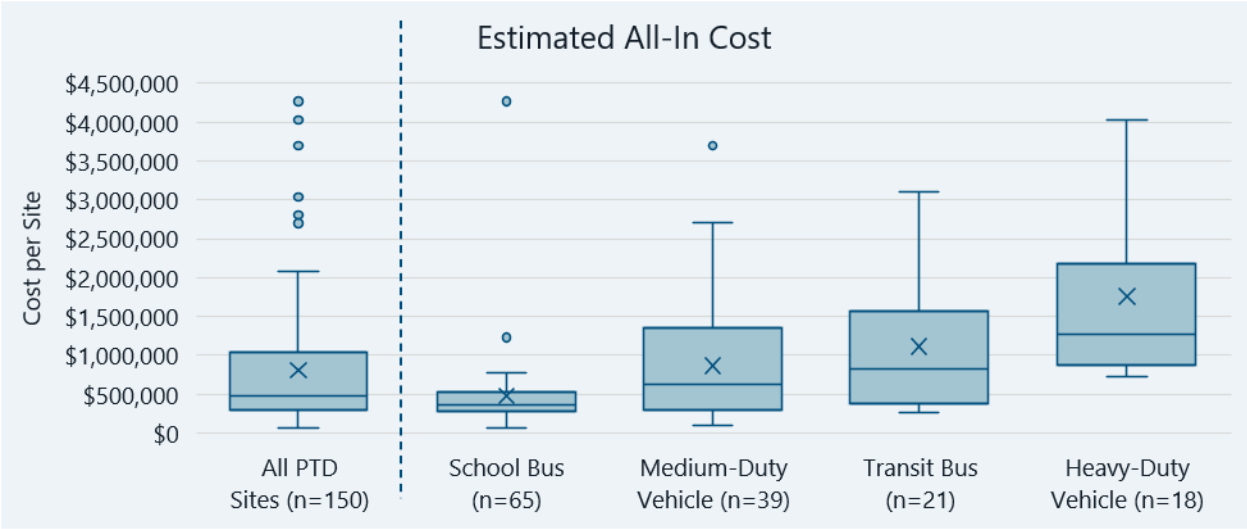


Figure 161 shows the average estimated all-in costs for the 150 sites, broken out by the four primary market sectors. For the school bus sites, TTM is the largest cost, followed by estimated BTM, then estimated EVSE. These costs total $475,338 for PTD sites.[84] For medium-duty vehicle sites, BTM is the largest estimated cost, followed by TTM, then estimated EVSE for a total of $868,098 for sites in the program to date. For transit bus sites, EVSE is the largest estimated cost, followed by TTM, then estimated BTM, for a total of $1,109,557 for PTD sites. For heavy-duty vehicle sites, EVSE is the largest estimated cost, followed by estimated BTM, then TTM, for a total of $1,758,600 for PTD sites. For all sites PTD, EVSE is the largest estimated cost, followed by estimated BTM, then TTM for a total cost of $810,420.[85] Although not shown, 42% of PG&E EV Fleet program spending on infrastructure for financially closed-out sites to date has been on DAC sites, exceeding the 25% program target.

[84] Calculated by summing all TTM, BTM, and EVSE costs borne by PG&E and the customer and dividing by 65 sites.

[85] Calculated by summing all TTM, BTM, and EVSE costs borne by PG&E and the customer and dividing by 95 sites.

Figure 161. PG&E EV Fleet Program Average All-In Costs Across 150 Closed-out PTD Sites

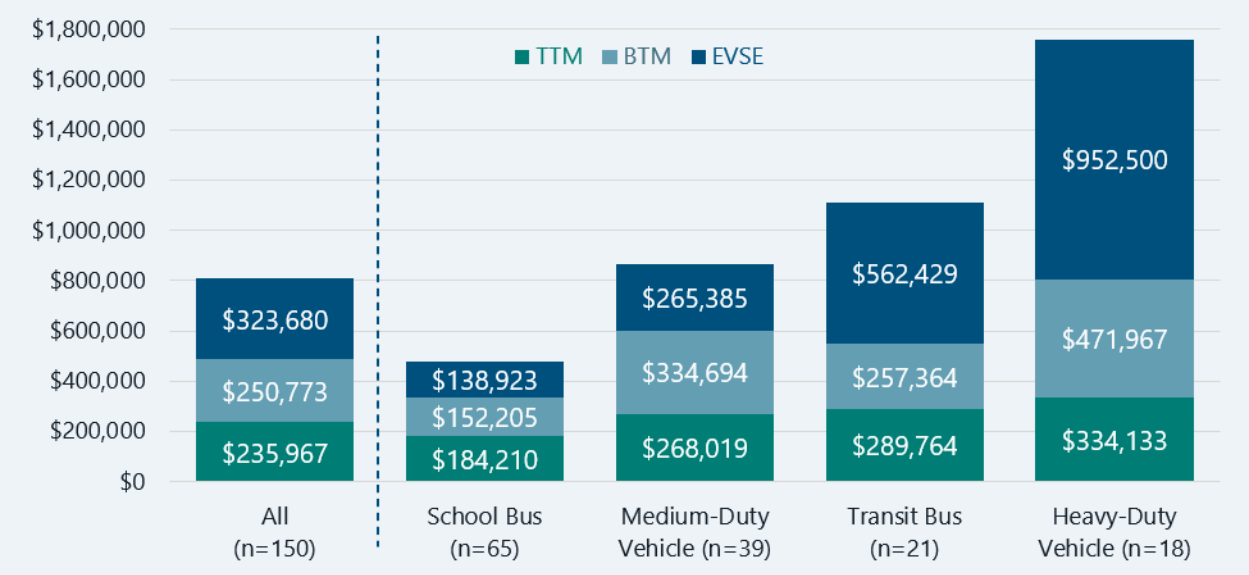


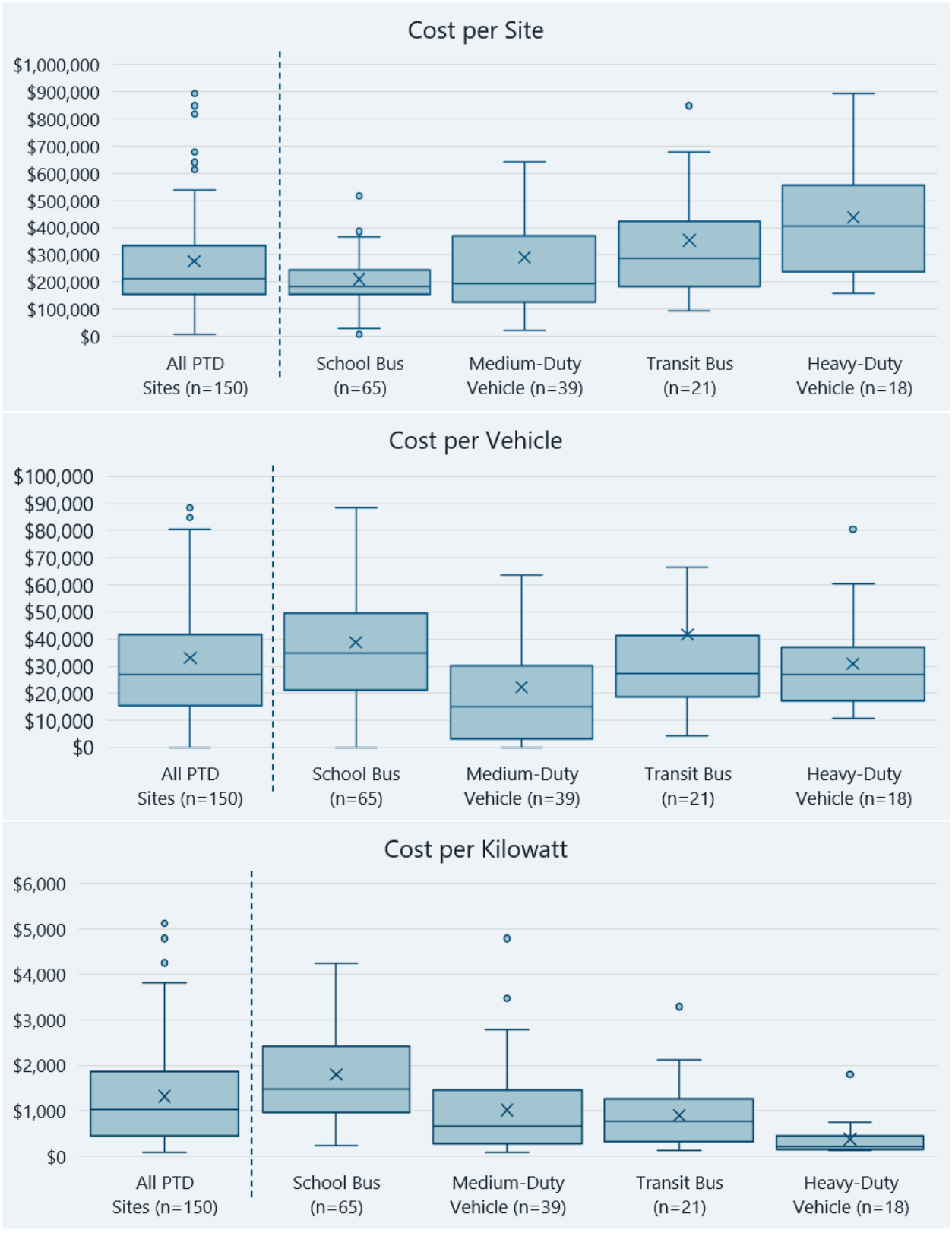
Figure 162 shows the distribution of Utility infrastructure costs presented per site, per vehicle, and per kilowatt. Similar to EY2024, school bus sites are less costly than non-school bus sites on a per site basis but more costly on a per kilowatt basis, reflecting the higher reliance on L2 chargers (which are more expensive per kilowatt for BTM, TTM, and EVSE) at school bus sites. School bus sites are more costly than non-school bus sites on a per vehicle basis. The average Utility infrastructure cost of TTM and BTM borne by PG&E across all 150 PTD sites was $275,712 per site,[86] $34,409 per vehicle,[87] and $1,317 per kilowatt.[88]

[86] Calculated by summing all TTM and PG&E-sponsored BTM costs and dividing by the number of sites. Number reflects maximum infrastructure rebate offered for sites that have not yet applied for rebates, which may vary significantly from actual infrastructure rebate amount paid.

[87] Calculated by summing all TTM and PG&E-sponsored BTM costs and dividing by the sum of all vehicles.

[88] Calculated by summing all TTM and PG&E-sponsored BTM costs and dividing by the sum of installed capacity.

Figure 162. PG&E EV Fleet Program, Utility Infrastructure Cost per Site, per Vehicle, and per Kilowatt for 150 Closed-out PTD Sites



Highlights

- Estimated all-in costs for school bus sites (i.e., estimates of 100% of the Utility and customer costs) vary widely between sites and average $475,338 for PTD sites.
- Estimated all-in costs for medium-duty vehicle sites (i.e., estimates of 100% of the Utility and customer costs) vary widely and average $868,098 for PTD sites.
- Estimated all-in costs for transit bus sites (i.e., estimates of 100% of the Utility and customer costs) vary widely and average $1,109,557 for PTD sites.
- Estimated all-in costs for heavy-duty vehicle sites (i.e., estimates of 100% of the Utility and customer costs) vary widely and average $1,758,600 for PTD sites.
- Only six of 150 closed out sites are Utility-constructed BTM infrastructure. The other 144 sites are site-owner installed BTM infrastructure.
- School bus sites are less costly than non-school bus sites on a per-site basis but more costly on a per-kilowatt basis, reflecting the higher reliance on L2 chargers (which are more expensive per kilowatt for BTM, TTM, and EVSE) at school bus sites.

Grid Impacts

This section describes grid impacts for the PG&E EV Fleet program based on an analysis of energy consumed by operational charging stations installed through the PG&E EV Fleet program through 2025, combined with customer bills.

Data Sources

The primary data source for the analyses detailed in this section is the energy usage–related data provided in regular 15-minute intervals from the AMI. Other data sources include customer bills, LCFS program information, and charging session–specific data provided by NSPs. There are several important differences between AMI and NSP data. While AMI data includes only energy usage, NSP data also includes session start and stop time, the duration of a vehicle's connection to a charging port, the duration of a vehicle actively pulling power, and the specific port used for a session. AMI meters track standing loads (such as those the EVSE uses for communications, cooling, active power converters, solenoids, and screens), which NSPs typically cannot do. For cases in which AMI data were missing from the dataset, the Evaluation Team used NSP data to fill the gaps.

Summary of Grid Impacts

Table 68 presents the estimated EV Fleet program grid impacts.

Table 68. PG&E EV Fleet Program Grid Impacts

Impact Parameter	Actual 2025 [b]	Actual PTD	10-Year Projection PTD
Operational Sites [a]	50	155	155
Installed Capacity (MW)	26.6	92.6	92.6
Electric Energy Consumption, MWh	32,737	62,455	315,632
On-Peak (4 p.m. to 9 p.m.) MWh (and % of total)	4,573 (14%)	10,817 (17%)	N/A
Maximum Demand, MW (with date and time)	18.8 (12/11/25 10:15 p.m.)	18.8 (12/11/25 10:15 p.m.)	N/A
Maximum On-Peak Demand, MW (with date and time)	8.1 (12/8/25 7:45 p.m.)	8.1 (12/8/25 7:45 p.m.)	N/A

[a] Only 50 (2025) and 155 (PTD) of all operational sites had sufficient data to be included in the impacts analysis

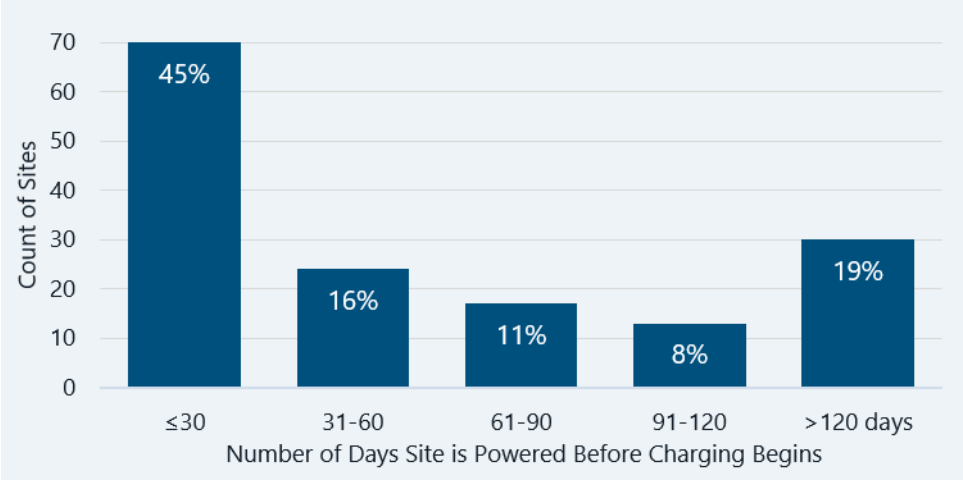
[b] Energy consumption, peak consumption, and demand data are based on PTD activated sites for calendar year 2025.

Energy Trends

Site Startup

The Evaluation Team examined the duration between EV Fleet program site activation and operation to illustrate the time between readiness of charging infrastructure and actual vehicle charging. AMI data indicate that almost 60% of sites in the EV Fleet program show significant operations within 60 days of activation, as illustrated in Figure 163. The number of projects that show more than 120 days between activation and operation decreased from 32% in EY2024 to just 23% in EY2025; however, the number of sites that began operations within 30 days of activation also decreased in EY2025 to 40% from 47% in EY2024. Accordingly, there are more sites taking between 31 and 90 days to become operational after activation in EY2025 than in EY2024.

Figure 163. PG&E EV Fleet Program Percentage of Sites by Days between Activation and Operation for PTD Sites



Consumption and Maximum Demand

Figure 164 depicts the growth of PG&E's monthly energy consumption and maximum demand for all operational sites in the EV Fleet program to date. Throughout 2025 consumption and maximum demand increased at a similar rate as in the prior two years.

PTD sites in the EV Fleet program collectively reached almost 19 MW of demand in 2025, with an installed capacity of 92.6 MW, up from a peak demand of 12 MW and installed capacity of 66 MW. As detailed in the *Site Visit Findings* section, the low demand relative to the installed capacity is likely due to several factors including fleet operators taking time to build expertise, work out EV or EVSE reliability, and wait for delivery of vehicles. Another factor is that some installed capacity may be intended for future vehicles across sites' five-year VAPs. Yet another consideration is that vehicles are not always able to accept the full power capacity of a given EVSE. For example, DCFC may deliver maximum power at a specific nominal battery voltage such as 800 V, but a vehicle may be limited to a 650 V battery.

One method of evaluation is to parse the data by sites' year of activation, similar to the Team's approach with annual site visit reporting. In theory the oldest sites have mature operations and may be the most stable and closest to final standing. Review of demand data reveals that the oldest group of sites (EY2021) has the highest ratio of maximum demand to installed charging capacity (48%). The demand ratio for sites activated in subsequent years ranges from 20% for EY2025 sites to 29% in EY2022, with EY2023 sites showing 23%, and EY2024 sites showing 28%. Age of operation does not appear to be correlated with the ratio of maximum demand to total installed charging capacity (not shown in figures). Further comparison of monthly energy consumption by site activation year can be seen in Figure 165, which shows that sites activated in 2021, 2022, and 2023 have a similar pattern of energy consumption.

Figure 164. PG&E EV Fleet Program Monthly Energy Consumption and Maximum Demand

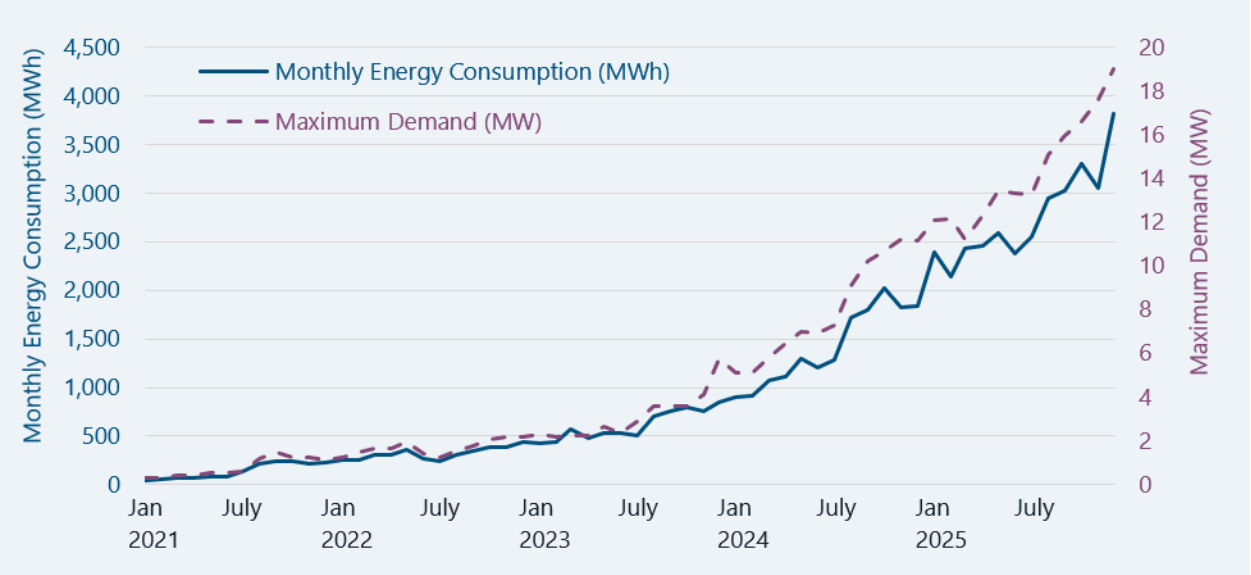


Figure 165 provides insight into monthly energy consumption trends of activated sites by program reporting year. Sites activated in EY2021 through EY2023 appear to have mostly consistent energy consumption after their first 18 months. Energy consumption for EY2024 sites is still growing at a steep rate, which shows that these sites have not yet reached operational maturity. EY2025 sites show a steeper growth rate than sites activated in previous years, and this growth is expected to continue past EY2026. Sites activated before EY2024 show a slower rate of growth though consumption has increased for several years. Sites activated from EY2021 through EY2023 have similar trends in consumption and represent fewer sites, with between 14 and 28 sites activated, compared with 60[89] in EY2025.

Figure 165. PG&E EV Fleet Program Monthly Energy Consumption of Activated Sites, Grouped by Initial Reporting Year

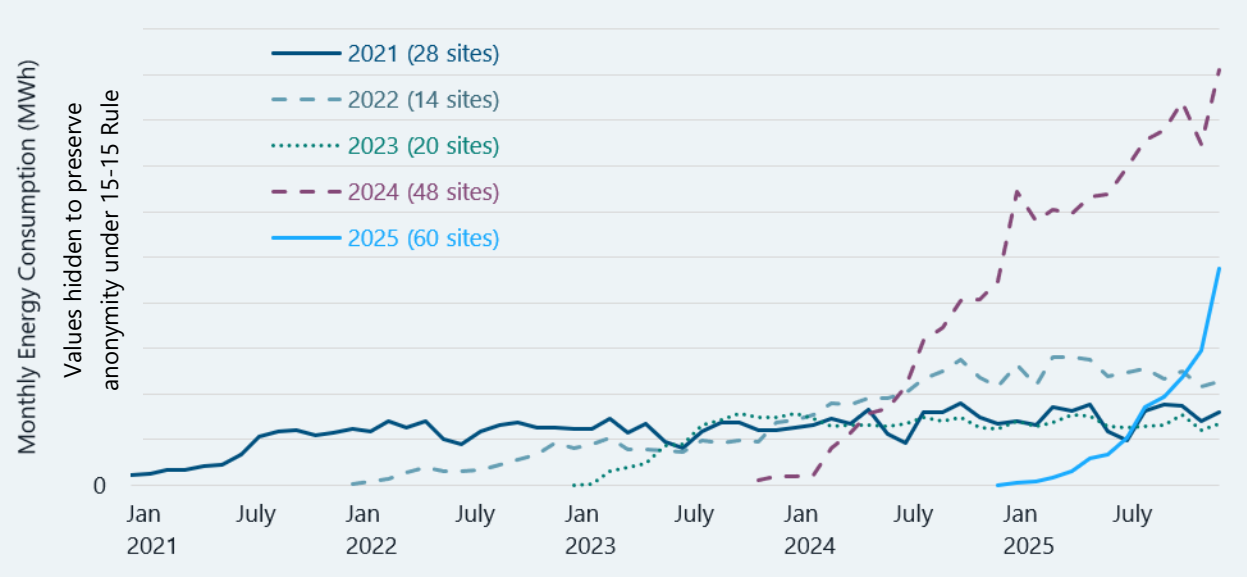
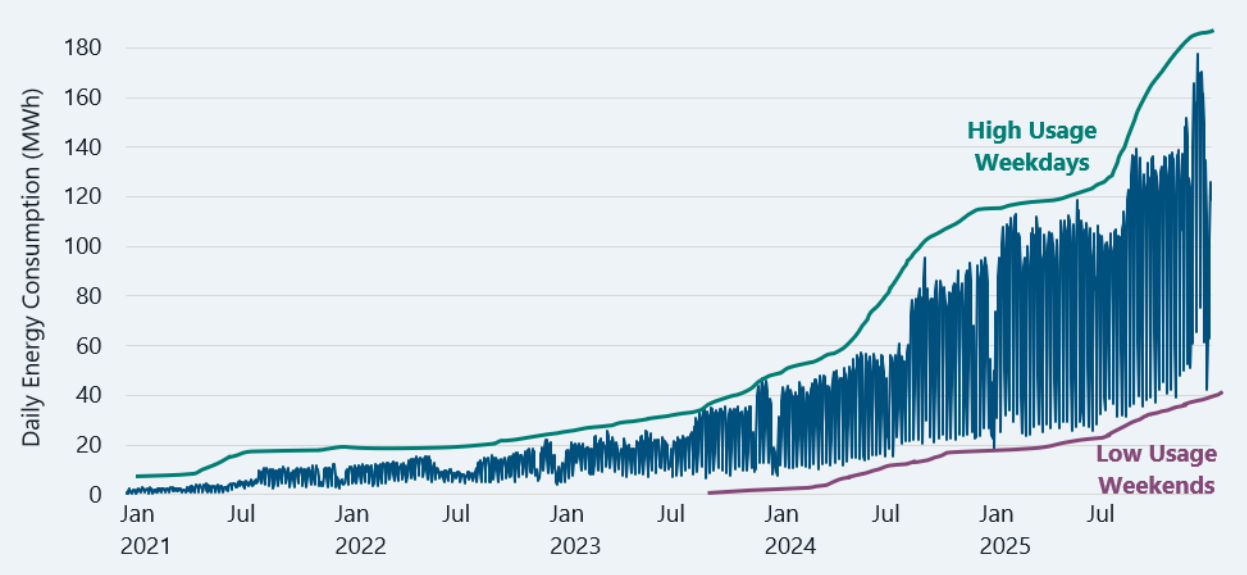


Figure 166 shows a wide variation in daily consumption between weekdays and weekends. The peaks typically represent weekday operation, and the dips typically represent weekend operation. Consumption increased steadily throughout 2025 from around 100 MWh at the start of the year to nearly 180 MWh at the end of the year. Consumption during weekends also increased, reaching over 60 MWh daily.

[89] Only 51 of the 60 EY2025 activated sites had sufficient data to be included in the impacts analysis.

Figure 166. PG&E EV Fleet Program Daily Energy Consumption for PTD Sites



Maximum demand for PTD sites continues to grow each year, as shown in Figure 167. Maximum demand rose from 12 MW in EY2024 to nearly 19 MW in EY2025. Weekend demand has also risen significantly, reaching around 8 MW per weekend day. The peak demand shown in Figure 167 represents approximately 21% of the total installed capacity of 92.6 MW for PTD sites.

Figure 167. PG&E EV Fleet Program Daily Maximum Demand for PTD Sites

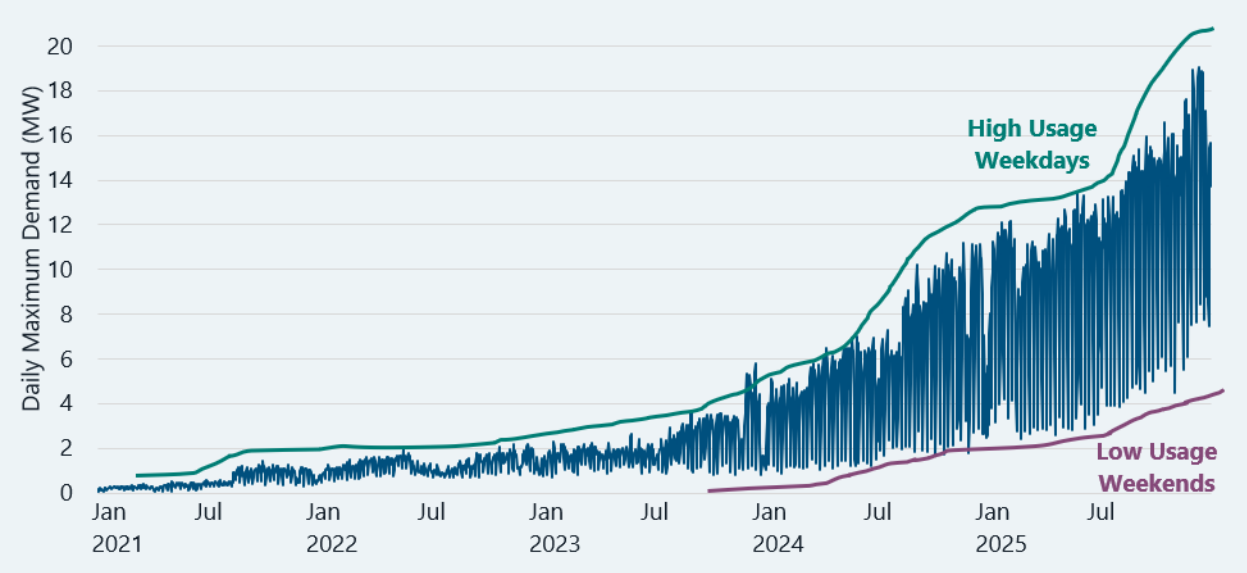
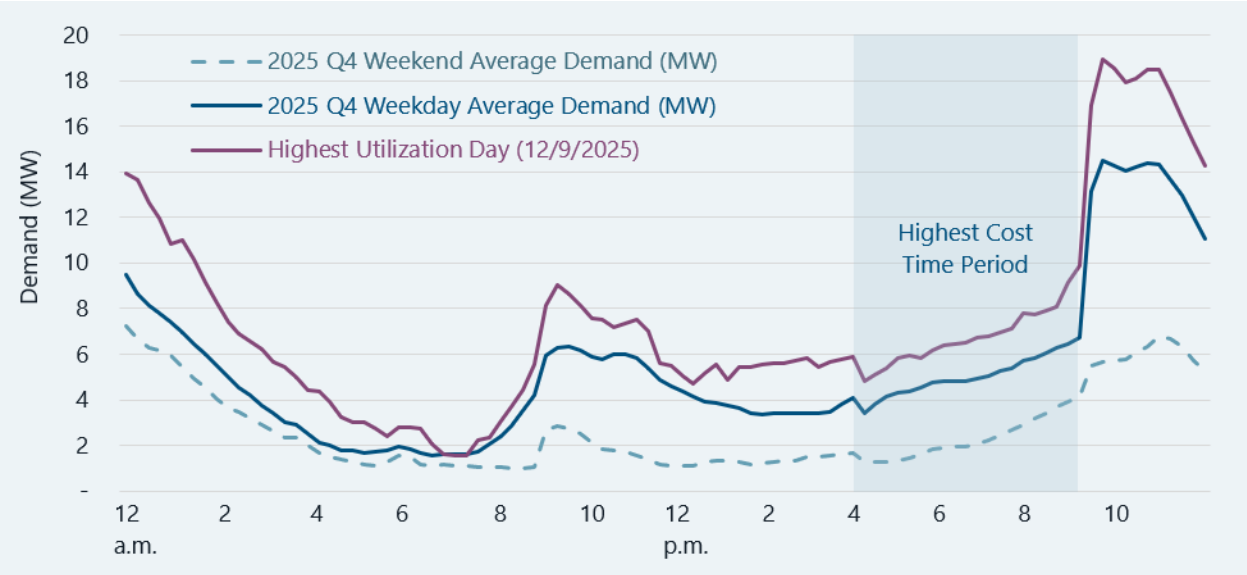


Figure 168 shows the average weekday and weekend daily load across all sites in the EV Fleet program for the final quarter of EY2025 as well as the day of highest consumption (which was also the day of highest demand) for comparison. Weekends show much less consumption and demand than weekdays. While load curves by day of week are not shown, Fridays have noticeably less demand than other weekdays. This

15% to 20% difference in demand may reflect that advanced fleets are shifting charging on Friday nights to PG&E's Super Off Peak (least cost and lowest emissions) time from 9 a.m. to 2 p.m., which is inaccessible for most fleets operating Monday through Friday aside from school buses. The load curves show a spike in demand at 9 p.m., which is consistent with load-managed fleets reinitiating charging to take advantage of lower cost electricity. These aggregated examples show the influence that a few substantial fleets adopting Load Management have on the overall portfolio.

Figure 168. PG&E EV Fleet Program Weekday and Weekend Q4 2025 Load Curves

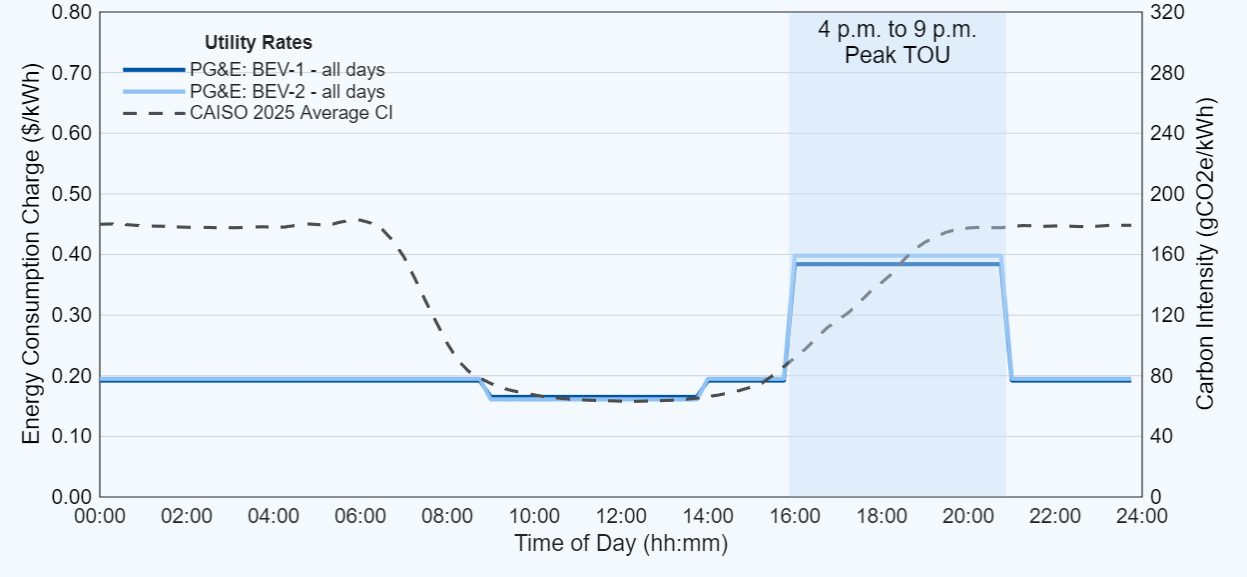


Load Management and Charging Flexibility Analysis

This section describes analyses around load management and load flexibility. Load-managed sites are those that adopt techniques to mitigate recurring high utility bills such as avoiding charging during periods of peak energy prices and reducing unnecessary speed of charging (kW). The analyses consider sites to be load-managed if they exhibited significant load management of six months or more in 2025; otherwise, they are labeled as non-load-managed. One indication of load management is the 9 p.m. load ramp that results from a site avoiding demand from 4 p.m. to 9 p.m. and shifting loads to periods of lower cost electricity.

PG&E's peak TOU period occurs each day from 4 p.m. to 9 p.m., during which hours the volumetric component of energy costs in 2025 was around $0.40/kWh under the BEV rate structure, versus below $0.20/kWh at other times. These TOU rates, displayed in Figure 169, apply to all days throughout the year. Lower-cost TOU periods, such as the Super-Off-Peak period from 9 a.m. to 2 p.m., often correlate with lower carbon intensity of the grid, as indicated by the dashed line in the figure, which shows the CAISO 2025 average carbon intensity (gCO_2e/kWh). As the actual carbon intensity of the grid varies continuously by time of day and day of year, this reference line indicates the time-of-day average across all days in 2025. PG&E also includes demand-subscription fees ranging from $1.24/kW to $2.00/kW. Fleets that have charging flexibility can reduce demand and charging speed to mitigate those costs.

Figure 169. PG&E EV Fleet Program Hourly TOU Electricity Rates and Average Carbon Intensity in 2025



The Evaluation Team periodically reviews data on a site-by-site basis throughout the year to identify load-managed sites. Visiting sites in person and speaking to fleet managers also provides context around load management intent and activity. Taking into account demand-related costs, the Team can use information about charging flexibility to estimate the minimum rate at which a vehicle can charge to mitigate and minimize demand.

Load management is evident in several ways:

- Load spikes quickly around 9 p.m.
- Charging often drops significantly at 4 p.m.
- The proportion of total monthly energy consumption used between 4 p.m. and 9 p.m. is often below 10%

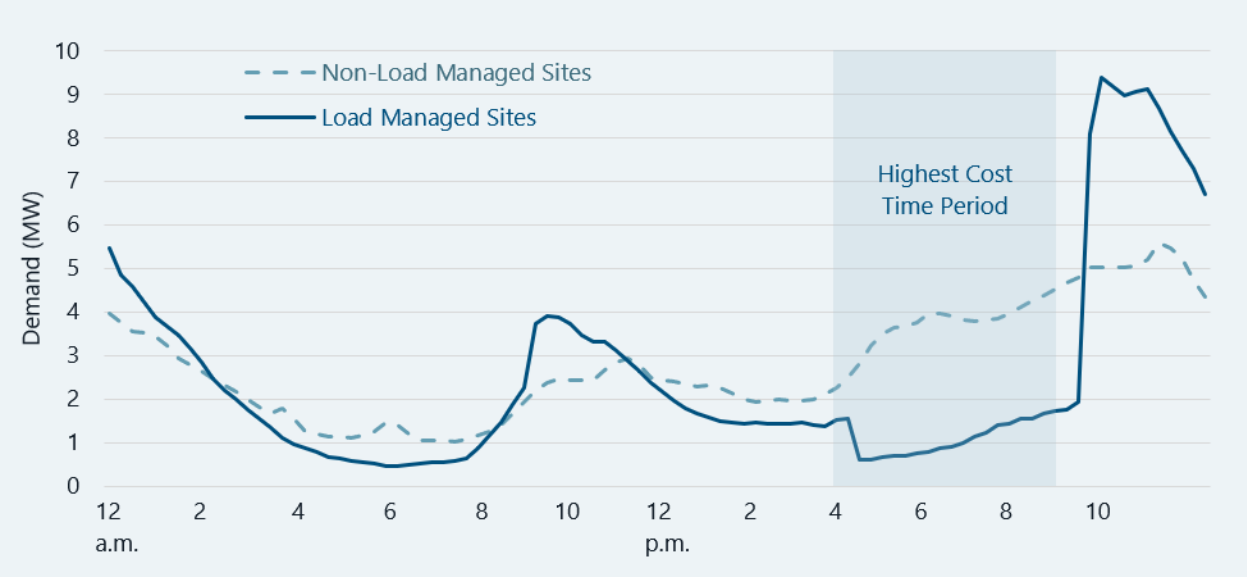
Of 155 operational sites, 33 exhibit strong indications of load management use based on trends of dropping load at 4 p.m. and increasing load at 9 p.m. as well as low proportion of consumption during the high-cost period as mentioned above. An additional nine show intermittent load management, including at least one with early operations that started at the end of 2025. Nine other sites the Team previously recorded as using load management no longer appear to use it.

Figure 170 illustrates the differences in electricity demand for load-managed and non-load-managed sites (determined using consumption data) in the fourth quarter of 2025. Both groups ramp up slowly starting at 8 a.m. with demand from load-managed sites peaking between 9 a.m. and 10 a.m. and demand from non-load-managed sites peaking an hour later. As shown, load-managed sites have consistently low demand throughout the highest-cost time period. Non-load-managed sites show a second demand peak just after 6 p.m., aligning with the end of many routes. On average nearly 4 MW of demand is being postponed to after 9 p.m. by load-managed sites. Non-load managed sites begin to ramp up demand at

4 p.m. with demand increasing steadily until 9 p.m. At that time, an additional 2 MW of demand occurs, which was likely delayed using load management. Despite this evidence of load management, these sites are considered non-load-managed as they did not show strong load management in 2025 because they either displayed inconsistent use of load management or had fewer than six months of available data.

Load appears to spike after the period of high-cost electricity, which indicates that vehicles may be charging at a higher speed than necessary. The *Charging Flexibility* section below shows the Team's efforts to quantify how fast vehicles need to charge and how much high-cost energy fleets need to consume. The *Costs and Billing* section reviews the results of modeling using charging flexibility to explore how fleets could reduce demand-oriented costs regardless of their load management practices.

Figure 170. PG&E EV Fleet Program Load-Managed and Non-Load-Managed Site Demand, 2025 Q4 (High Consumption and Demand Months), PTD Sites



Charging Flexibility

The Evaluation Team used site charging data to determine charging flexibility, or the amount of time vehicles are connected to a charging port but not actively consuming energy. This allowed the Team to assess to the degree to which vehicles could shift charging from periods of high-cost electricity to low-cost electricity without impacting vehicle operations. Site visits also allowed the Evaluation Team to confirm vehicles' make, model, and battery size, all of which affect charging flexibility, as well as operational characteristics. For instance, many school bus charging sessions use less than half of the vehicle's battery capacity. Providing feedback to fleet operators about historical usage trends, charging session size in relation to battery size, and available time to charge may help inform charging plans.

Figure 171 shows the relative charging flexibility of various vehicle market sectors school bus and non-school bus fleets. The figure includes only charging sessions that took place partially or entirely during periods of highest cost electricity and omits charging sessions that did not overlap with the period between 4 p.m. and 9 p.m.

Figure 171. PG&E EV Fleet Program Charging Flexibility for PTD Sites in Sessions Overlapping the Time Period Between 4 p.m. and 9 p.m.

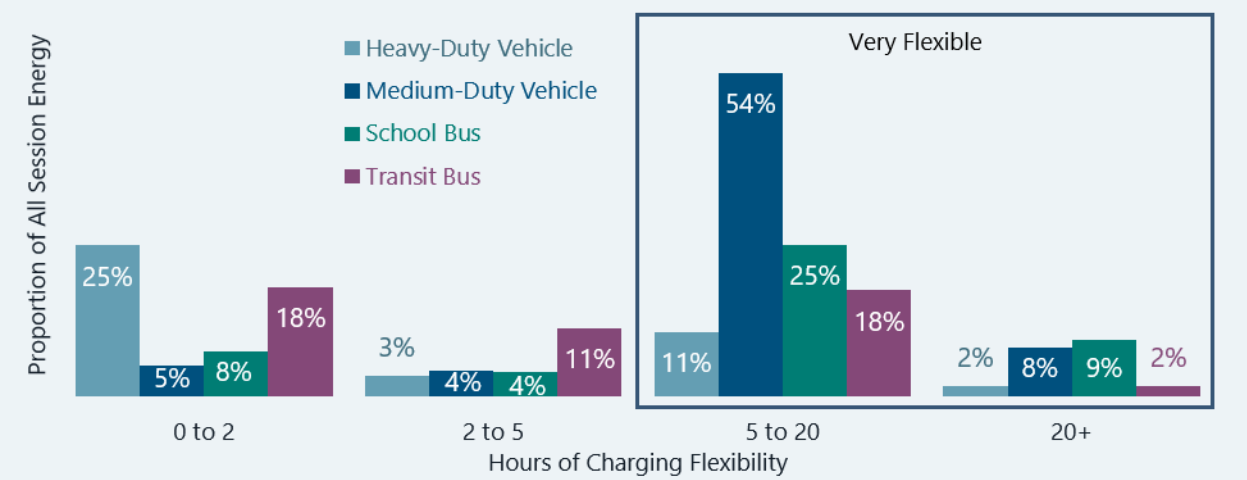


Figure 171 shows that a high proportion of energy consumption from charging sessions is from vehicles with enough flexibility to entirely avoid the highest-cost time period. Because the period of highest-cost electricity lasts for five hours (4 p.m. to 9 p.m.), vehicles require at least five hours of charging flexibility (and more time for longer charging sessions) to fully shift consumption from on-peak to off-peak periods.

As shown, over 60% of the energy consumed by vehicles in the medium-duty vehicle market sector both overlaps the 4 p.m. to 9 p.m. period and has enough flexibility to be shifted to lower-cost periods. The school bus market sector also has significant opportunity to shift almost 35% of charging to lower cost periods. The transit bus and heavy-duty vehicle market sectors have smaller, but still meaningful opportunities to implement load management and reduce costs, with flexibility to shift 20% and 13% of energy consumed, respectively.

Fleets operating a single shift generally have the most time available to benefit from load management, while fleets operating multiple daily shifts face the most time constraints to leveraging load management, as vehicles charge throughout the day supporting longer operations. However, while it is more difficult for sites with multiple shifts to avoid charging during the 4 p.m. to 9 p.m. period, these sites also tend to have significant consumption at low-cost times of day. This can avoid typical peak consumption aligned with the end of the typical workday (5 p.m.), which reduces the proportion of overall charging that takes place from 4 p.m. to 9 p.m., resulting in lower average energy costs

Costs and Billing

The total sum of the monthly billing costs for activated sites in the program to date amounts to $16.5 million. Previous sections have focused on energy trends and charging flexibility, identifying that significant charging is taking place during the peak period of 4 p.m. to 9 p.m. and that much of this load could be shifted to periods of lower demand. The following section examines Utility cost and billing trends and explores to what extent sites may reduce costs based on charging flexibility. The Evaluation Team's review of billing data focuses on the average unit cost of a kilowatt-hour for a given month

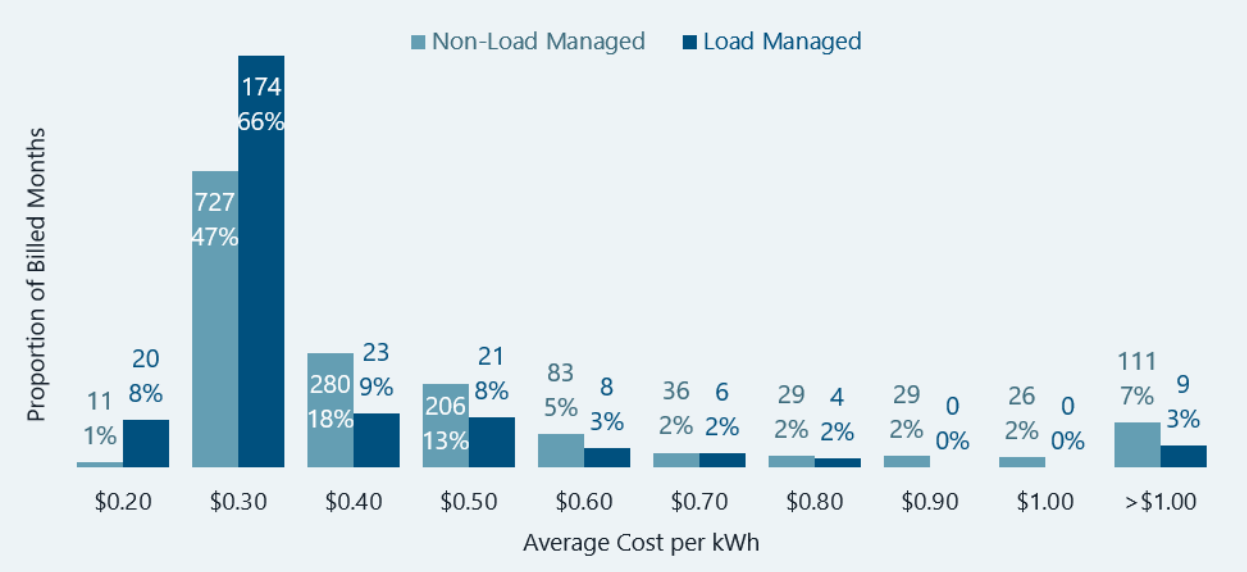
compared with the TOU-based tariff cost of energy. The following charts group data by kilowatt-hours of billing months for sites, not by the actual sites.

NSPs' load management capabilities and fleets' adoption of load management impact costs and energy trends. NSPs that offer load management may structure it as a base offering or tiered-cost package. Interoperability between hardware, software, and vehicles may also presents challenges that can make load management impractical or difficult to achieve. By the end of 2025, nearly 25 NSPs were servicing PG&E customers in the EV Fleet program. Of 155 operational sites, 33 sites show either strong load management or a natural tendency to conduct a significant amount of charging outside of the period between 4.p.m, and 9 p.m. Two NSPs within this portfolio have a nearly perfect track record of engaging load management. Another five to seven NSPs show low use of load management, while more than 15 NSPs have no discernible load management or have said that they do not offer this solution.

Many fleet operators remain unaware of their energy use and charging costs despite receiving utility bills and the data being available from most EVSPs. Often a site host's finance office will receive utility bills but will not share information with fleet operators that would enable them to compare energy costs for the fuel types in their fleets. The Evaluation Team uses data on energy consumption trends as discussion points during site visits if operations have started. Many fleet operators have said they had not seen these data trends prior to the evaluation site visits. A detailed analysis of these issues is presented in the *Barriers and Solutions to Load Management* section.

Figure 172 shows the distribution of the average monthly electricity costs per kilowatt-hour for PTD sites with billing data in 2025. PG&E base rates range from approximately $0.13/kWh to $0.35/kWh, before adding demand-subscription charges, service fees and taxes. Nearly 50% of billing months show costs of between $0.20/kWh to $0.30/kWh. Approximately 10% of sites are able to achieve average monthly electricity costs of less than $0.10/kWh, while another 10% pay an average of $0.60/kWh or more.

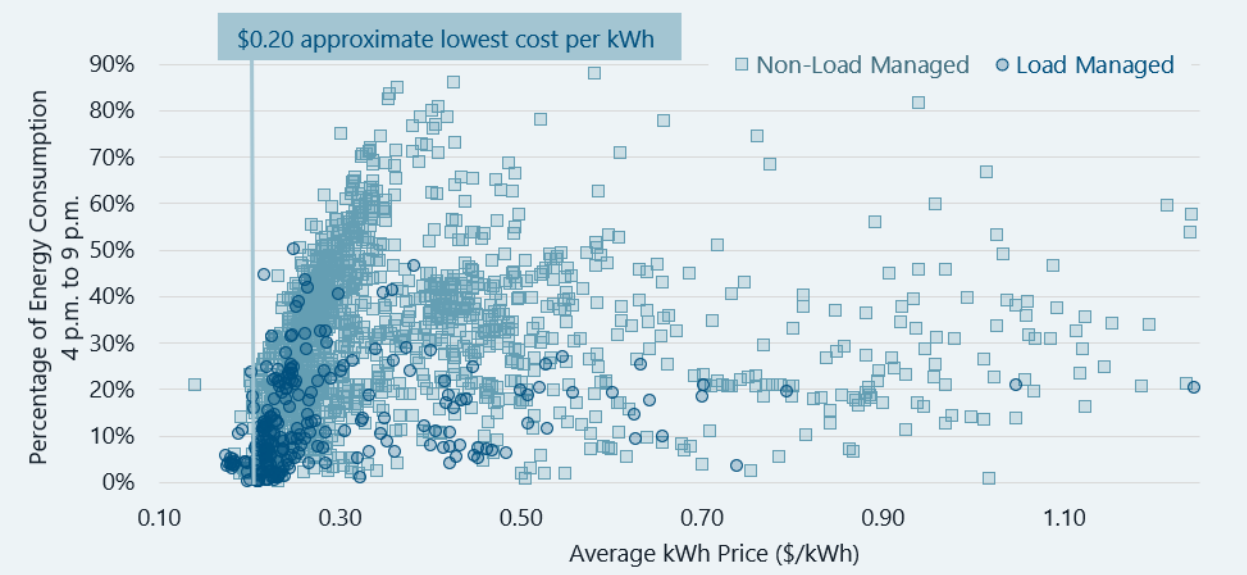
Figure 172. PG&E EV Fleet Program 2025 Monthly Electricity Costs



1,800 billing months in 2025, which includes some overlapping billing months in January and December.

Figure 173 shows all 2025 billing months with color coding by whether or not the fleet was observed to have used load management in 2025. The data points show that load-managed billing months trend to lower average energy costs, which is a direct benefit for the fleet. This also shows that these fleets consume lower proportion of energy between 4 p.m. and 9 p.m., which benefits ratepayers and utilities.

Figure 173. PG&E EV Fleet Program 2025 All Billing Months Average Electricity Costs per Kilowatt-Hour for Load-Managed and Non-Load-Managed Sites



To better highlight energy and billing trends, Figure 174 and Figure 175 show these trends across sites, grouped by high, medium and low billing months relative to total megawatt-hours consumed. Each dot represents a billing month.

Figure 174 illustrates the positive relationship between the percentage of on-peak energy consumption and the average monthly customer bills for months over 20 MWh. 2025 data show increased costs coincident with an increased proportion of energy consumed between 4 p.m. and 9 p.m. Minimum costs appear to be around $0.20/kWh for large billing months. Very few months cost over $0.35/kWh.

Figure 174. PG&E EV Fleet Program Percentage of Monthly Energy Consumed from 4 p.m. to 9 p.m. vs. Average Energy Price for High Consumption Billing Months (>20 MWh) for PTD Sites

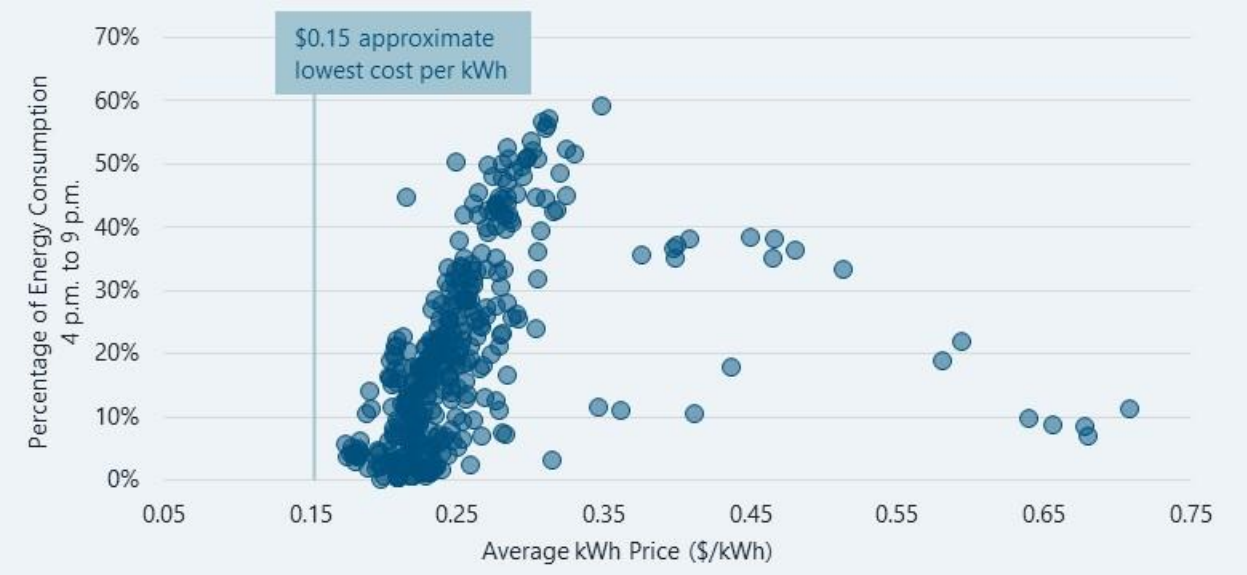


Figure 175 shows the relationship between the percentage of on-peak energy consumption and average cost per kilowatt-hour for customer bills ranging between 5 MWh and 20 MWh of energy. These also show increased costs coincident with an increased proportion of energy consumed between 4 p.m. and 9 p.m.; however, a higher proportion of months in this group are above $0.40/kWh than in months that have the largest billing months. Many of the sites that have adopted load management achieve costs less than $0.30/kWh, offering a significant opportunity for their fleets.

Figure 175. PG&E EV Fleet Program Percentage of Monthly Energy Consumed from 4 p.m. to 9 p.m. vs. Average Energy Price for Medium Consumption Billing Months (5 MWh to 20 MWh) for PTD Sites

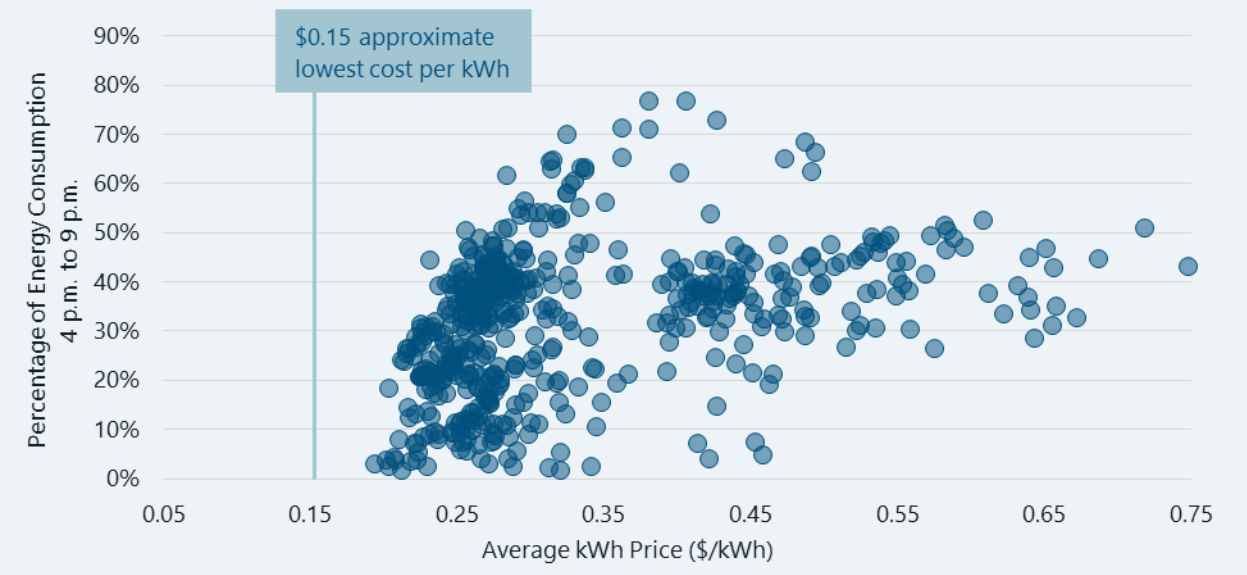


Figure 176 takes the same group of medium billing months (5 MWh to 20 MWh) and looks at the correlation between average unit pricing and overall monthly energy consumption. While the majority of large months (>20 MWh) have an average cost below $0.25/kWh, medium months are clustered in the $0.25/kWh to $0.30/kWh range. The figure also shows that months with the highest electricity costs tend to be those with lower monthly energy consumption.

Figure 176. PG&E EV Fleet Program Total Monthly Energy Consumed vs. Average Energy Price for Medium Consumption Billing Months (5 MWh to 20 MWh) for PTD Sites

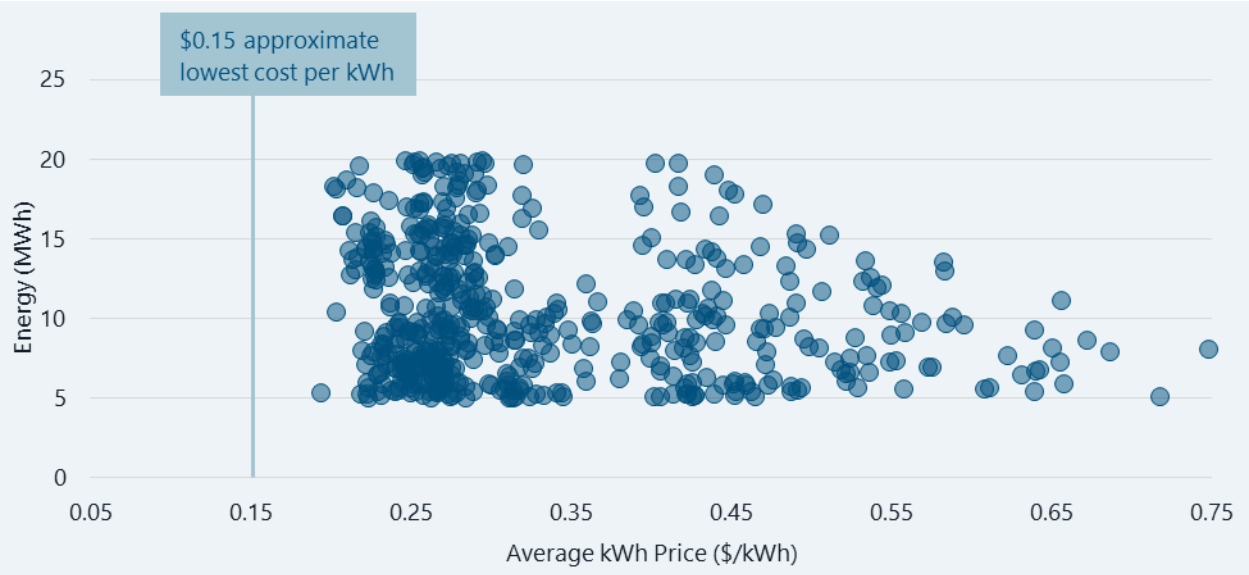
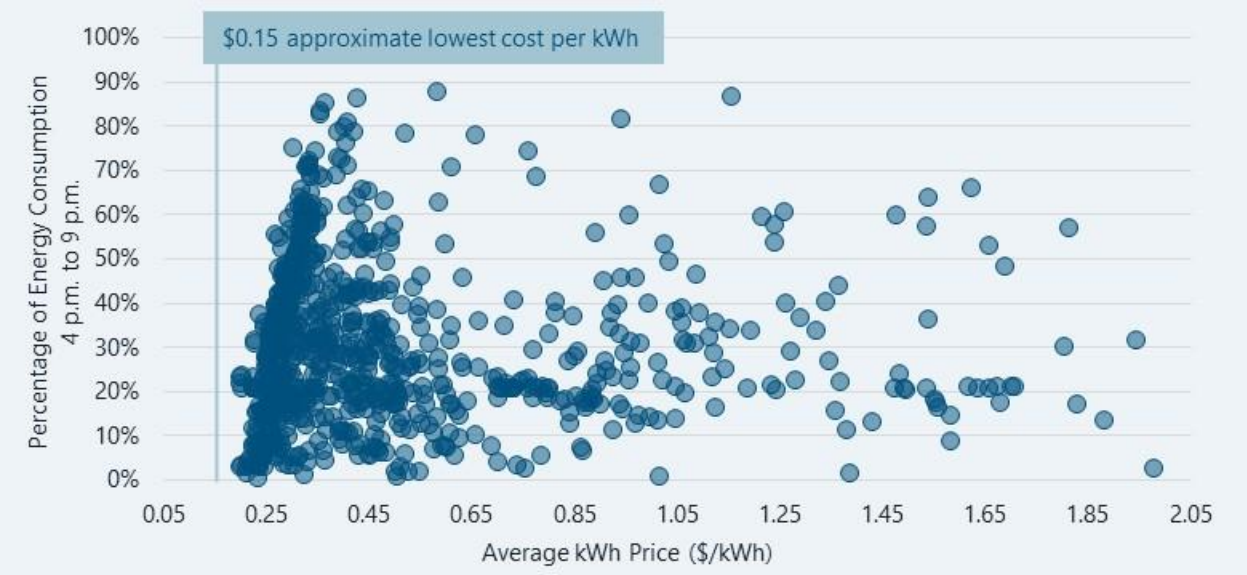


Figure 177 shows the relationship between percentage of on-peak energy consumption and average monthly customer bills for low billing months (<5 MWh). Low billing months show a similar correlation between energy costs and the proportion of consumption from 4 p.m. to 9 p.m. highlighting the opportunity for low energy users to reduce costs by using load management. Due to fixed fees, which are spread across the total kilowatt-hours consumed and therefore have a greater impact on sites with lower total consumption, it is unlikely that fleet operators with small billing months will be able to achieve electricity costs as low as costs for medium and high months; however, these sites will still be able to significantly reduce costs by leveraging lower cost TOU pricing.

Figure 177. PG&E EV Fleet Program Percentage of Monthly Energy Consumed from 4 p.m. to 9 p.m. vs. Average Energy Price for Low Consumption Billing Months (<5 MWh) for PTD Sites



Fleets that used less than 5 MWh per month show a correlation between average unit pricing and overall monthly consumption; more consumption leads to lower average costs. Monthly billing is typically between $0.30/kWh and $0.35/kWh, for an average cost more than 30% higher than for large billing months. Figure 178 further illustrates that months of the lowest energy consumption are likely to have higher electricity costs per kilowatt-hour, with many months exceeding $1.00/kWh and several exceeding $1.50/kWh, as opposed to $0.75/kWh as the highest monthly cost for medium- and high-consumption months. This again may be attributed to fixed fees, which are spread across the total kilowatt-hours consumed and therefore have a greater impact on sites with lower total consumption; however, the higher costs are also important as smaller fleets are often the most impacted by higher electricity costs, and therefore are poised to have the greatest benefit from implementation of load management.

Figure 178. PG&E EV Fleet Program Total Monthly Energy Consumed vs. Average Energy Price for Low-Consumption Billing Months (<5 MWh) for PTD Sites



Electricity Cost and Emissions Optimization Analysis

This section builds upon the grid impact findings above to include an analysis of hypothetical customer bills and emissions. This analysis considered TOU-based load management across sites with sufficient reliable NSP data. While real-world constraints—such as from technology, operations, and education—currently prevent ideal load management, the findings shed light on its long-term potential. To quantify the potential benefits of using load management, the Evaluation Team analyzed observed outcomes of sites with and without existing load management practices and conducted a load-shifting optimization exercise to estimate the total potential cost savings and emissions reductions. This optimization analysis utilizes NSP data, where available, to assess charging flexibility for each site. For sites without sufficient NSP data reported, the analysis uses AMI data and a charging session availability template to assess charging flexibility. The template is derived for each market sector based on the charging behavior of sites with NSP charging session data within each sector.

Load Management Outcomes Observed in EY2025

Of 155 operational PTD sites, the Evaluation Team assessed 130 sites with AMI and NSP data that met the requirements for analysis. Of these 130 sites, 53 were school bus sites and 78 were from other market sectors, including transit bus, medium-duty vehicle, heavy-duty vehicle, port cargo truck, and forklift.

Figure 179 and Figure 180 depict the BAU historical energy consumption of school bus fleets and non-school bus fleets, respectively, in aggregate during 2025. BAU represents the current charging behavior of the 130 sites used for this analysis. The areas in the figures with darker shading correspond to times of day (y-axis) and days throughout the year (x-axis) with higher collective charging demand, as measured by the scale on the right of the plot. Areas with no shading represent no energy demand. The colored regions of the plot correspond to the Utility's TOU highest-cost (4 p.m. to 9 p.m.) and lowest cost (10 a.m.

to 2 p.m.) periods. School bus fleets (Figure 179) show a consistent trend of charging twice per day: once beginning around 9 a.m. after the morning routes to pick up students, and again between 4 p.m. and 5 p.m. after buses complete afternoon runs. The second charging session directly coincides with higher TOU rates. It appears that many school bus sites are not delaying their charging sessions until after 9 p.m. to avoid peak TOU energy costs. The figure shows lower demand during winter break, spring break, and summer vacation periods when school bus operation is minimal and indicates that many schools deployed more electric buses, increased their usage, or both after returning from the summer break (as seen by the increased demand in August), which reflects the continued program growth in 2025. Non-school bus sites (Figure 180), show significant energy consumption after 9 p.m., which is from a few large sites that are avoiding charging during the higher-cost peak TOU period. These sites also saw continued growth throughout 2025, as shown by the steadily increasing maximum demand.

Figure 179. PG&E EV Fleet Program Heatmap of the Collective BAU Charging Demand for All PG&E School Bus Fleets in 2025

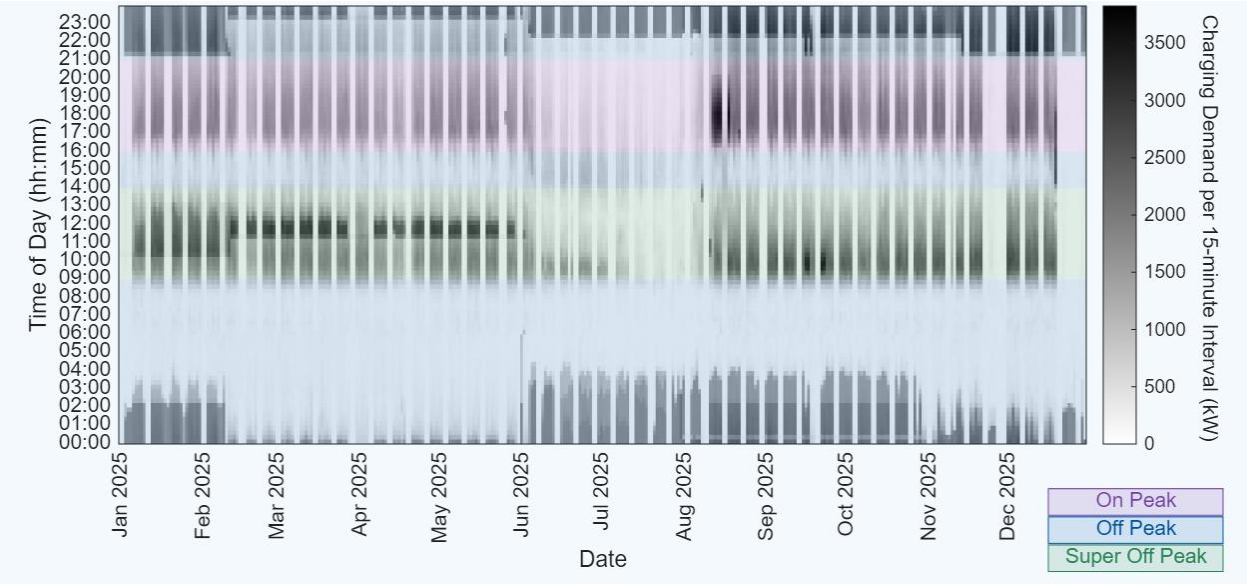
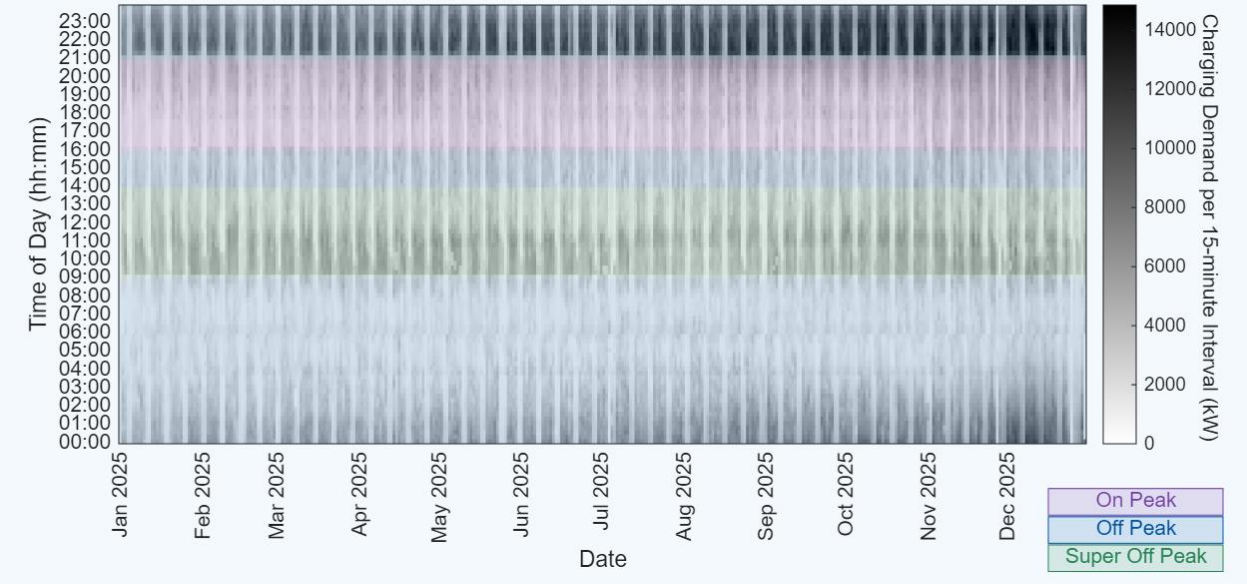


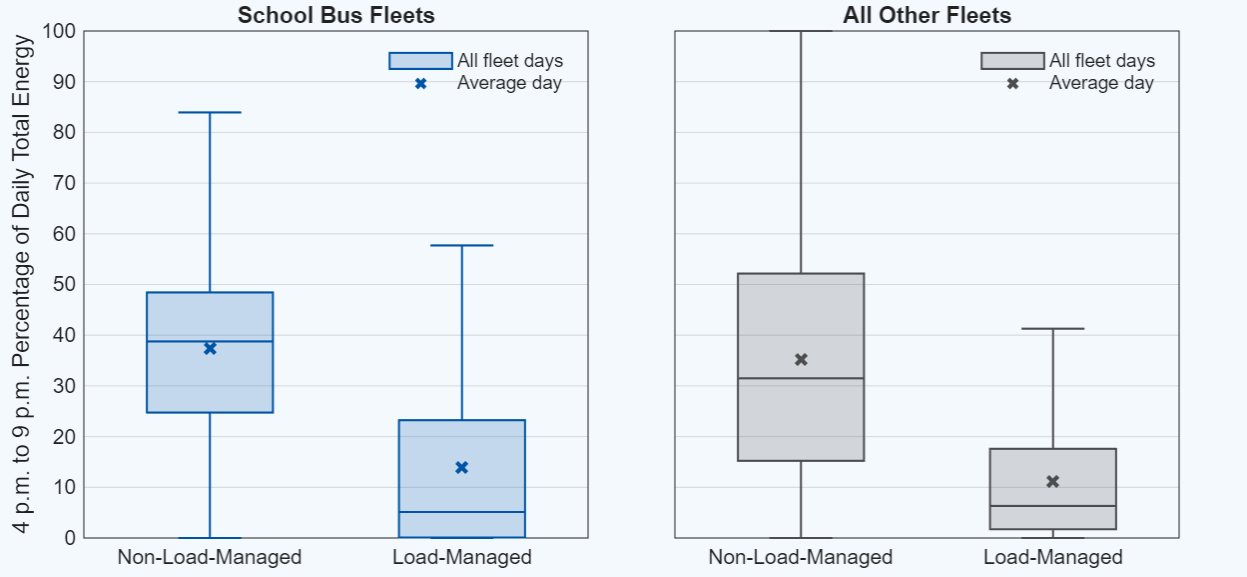
Figure 180. PG&E EV Fleet Program Heatmap of the Collective BAU Charging Demand for All PG&E Non-School Bus Fleets in 2025



The Evaluation Team compared NSP charging sessions that utilized load management strategies to non-load-managed sessions for the school bus and non-school bus fleets to evaluate the effectiveness of the existing load management at minimizing energy during the 4 p.m. to 9 p.m. peak TOU period.

The box plots in Figure 181 compare the distributions of daily on-peak (4 p.m. to 9 p.m.) energy consumption, as a percentage of daily total energy, between load-managed and non-load-managed days. On average, non-load-managed school buses show approximately 37% of daily consumption occurring between 4 p.m. and 9 p.m. For the average load-managed day, the percentage decreases to less than 14% of overall consumption. For other market sectors (shown on the right), the average non-load-managed day has approximately 35% of consumption during the peak TOU period, compared with approximately 11% for load-managed days.

Figure 181. PG&E EV Fleet Program Distribution of the Fraction of Daily EV Charging Load Occurring in the Peak TOU Period



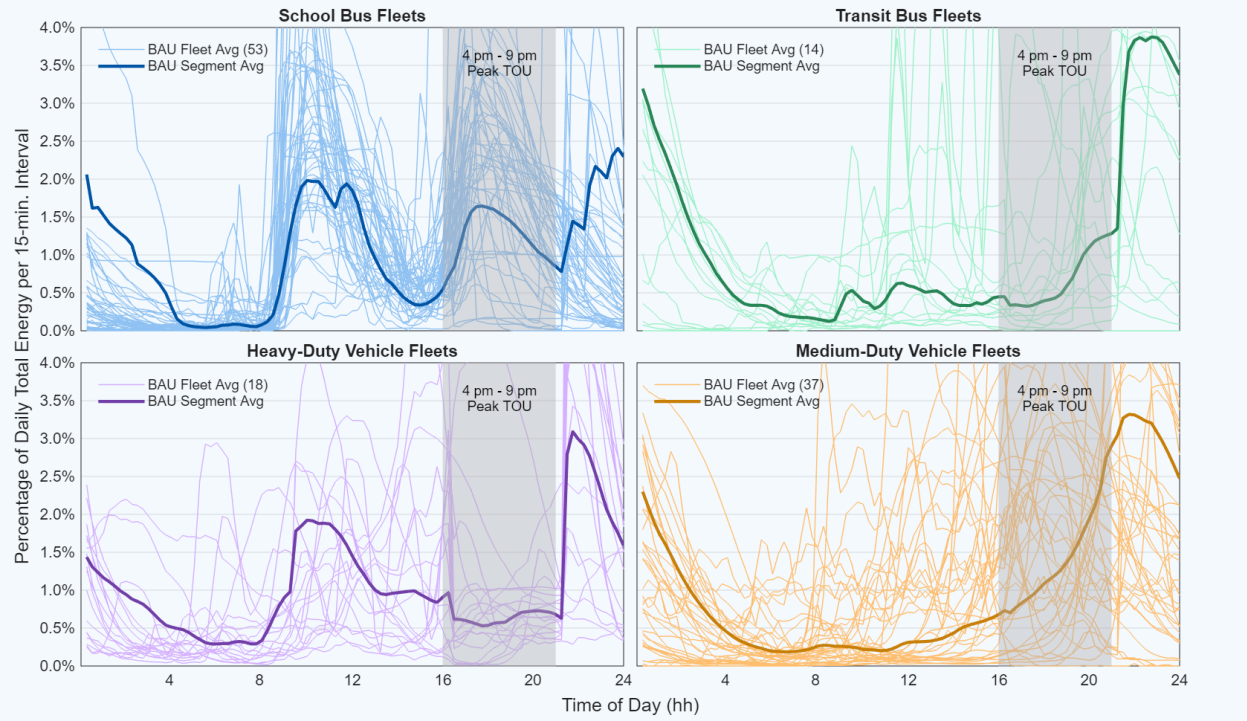
The box and whisker plot represents the distribution of daily total energy consumed from 4 p.m. to 9 p.m. across one operating day by group, and the average value for all operating days per group is indicated by an X.

This comparison suggests that existing load management programs reduce the fraction of energy consumed during peak hours and therefore reduce the energy costs, and detrimental impacts to the grid. However, outcomes vary substantially across sites (both load-managed and non-load-managed), suggesting that the value of load management depends on each site's operating patterns, charging flexibility, and on the chosen implementation of load management controls.

The faint lines in Figure 182 show the BAU average charging load curve for each fleet in 2025, for each of the four primary market sectors—school bus, transit bus, heavy-duty vehicle, and medium-duty vehicle. The annual load curves from all sites within each market sector are combined to show the 2025 overall average load curve for that market sector, displayed as a bold line.

These BAU curves highlight operational differences between vehicles in the various market sectors and therefore show the differences in charging opportunities that are revealed by these charging patterns. Despite some of the variability in the different sites, it is clear that school bus fleets consistently charge once during the middle of the day and then typically begin charging again between 4 p.m. and 6 p.m., although some delay charging until after 9 p.m. Transit bus sites, however, utilize very little midday charging, but demonstrate significant load management controls to begin charging after 9 p.m. Medium-duty vehicle sites demonstrate little to no load management to avoid the high-cost TOU period, and charging ramps up quickly throughout the evening as vehicles return after completing their work days. Lastly, heavy-duty vehicles in this data set show some charging in late morning and delayed evening charging after 9 p.m.

Figure 182. MDHD Load Curve Density Chart of Business as Usual per Fleet and by Portfolio



Potential Benefits of Load Management

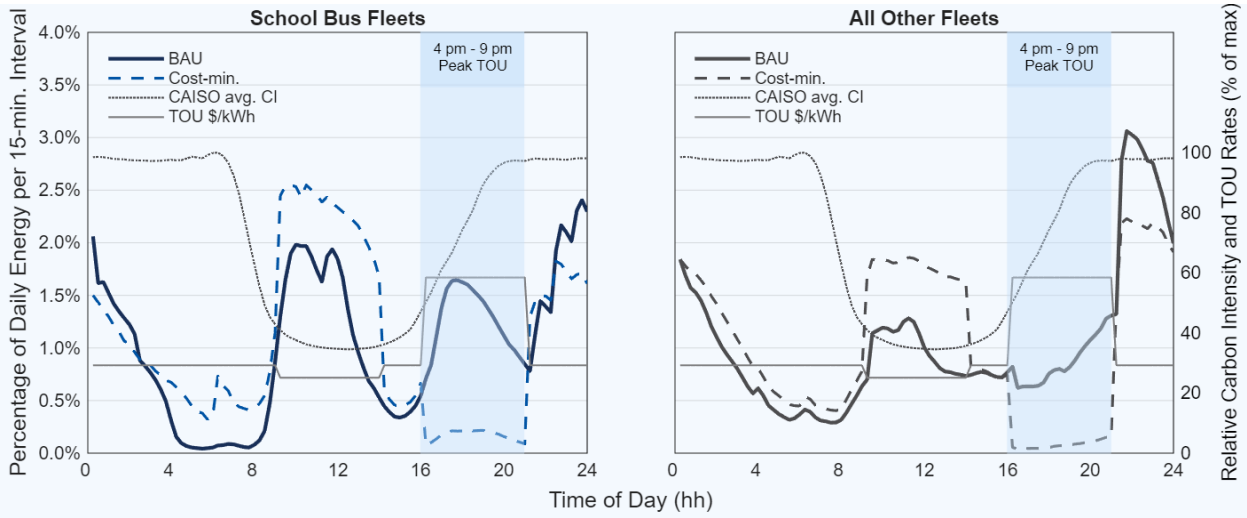
The Evaluation Team analyzed charging session data to estimate the value of optimal load management, considering each site's observed operating patterns and potential ability to shift vehicle charging loads. This analysis included 53 school bus sites and 77 sites in other market sectors that had sufficient AMI and NSP data reported for EY2025 to complete the optimization algorithm.

The Evaluation Team developed and executed an optimization routine that reviews each site's daily charging behavior and shifts energy consumption from the peak time period (4 p.m. to 9 p.m.) to lower-cost periods of the day whenever there was both unused charging capacity and vehicle charging availability during those periods. The Evaluation Team used NSP charging session data to ascertain how many vehicles were plugged in and how many kilowatt-hours of energy could be shifted during each time period. For hours in the same TOU rate period, the Team used carbon intensity of the electric grid (evaluated from CAISO 2025 GHG emissions factors) and BAU charging load as tiebreakers to determine vehicle charging priorities. The optimization algorithm also incorporates any monthly demand charges that may be incurred at the site from vehicle charging and minimizes the total charging costs in the optimization. The Team then calculated the resulting costs and GHG emissions for the load-shifted case and compared the results to the BAU case to determine cost-reduction and GHG-reduction potential for each site.

Figure 183 illustrates how optimally shifted loads differ from BAU loads, averaged across EY2025. For both school bus and other market sector sites, the average day's load can be almost completely shifted out of the high-cost 4 p.m. to 9 p.m. window and into midday charging (9 a.m. to 2 p.m.), overnight charging

(after 9 p.m.), or both. These time periods offer the lowest energy consumption costs, and the midday charging period (which has super-off-peak rates year-round) also corresponds to the lowest average carbon intensity of grid electricity.

Figure 183. PG&E EV Fleet Program Fraction of Daily EV Charging Load Occurring at Each 15-Minute Interval for the Average Day in this Analysis, BAU Compared with Cost-Minimization



Line color indicates site market sector and dashed versus solid lines indicate whether the load is BAU or shifted.

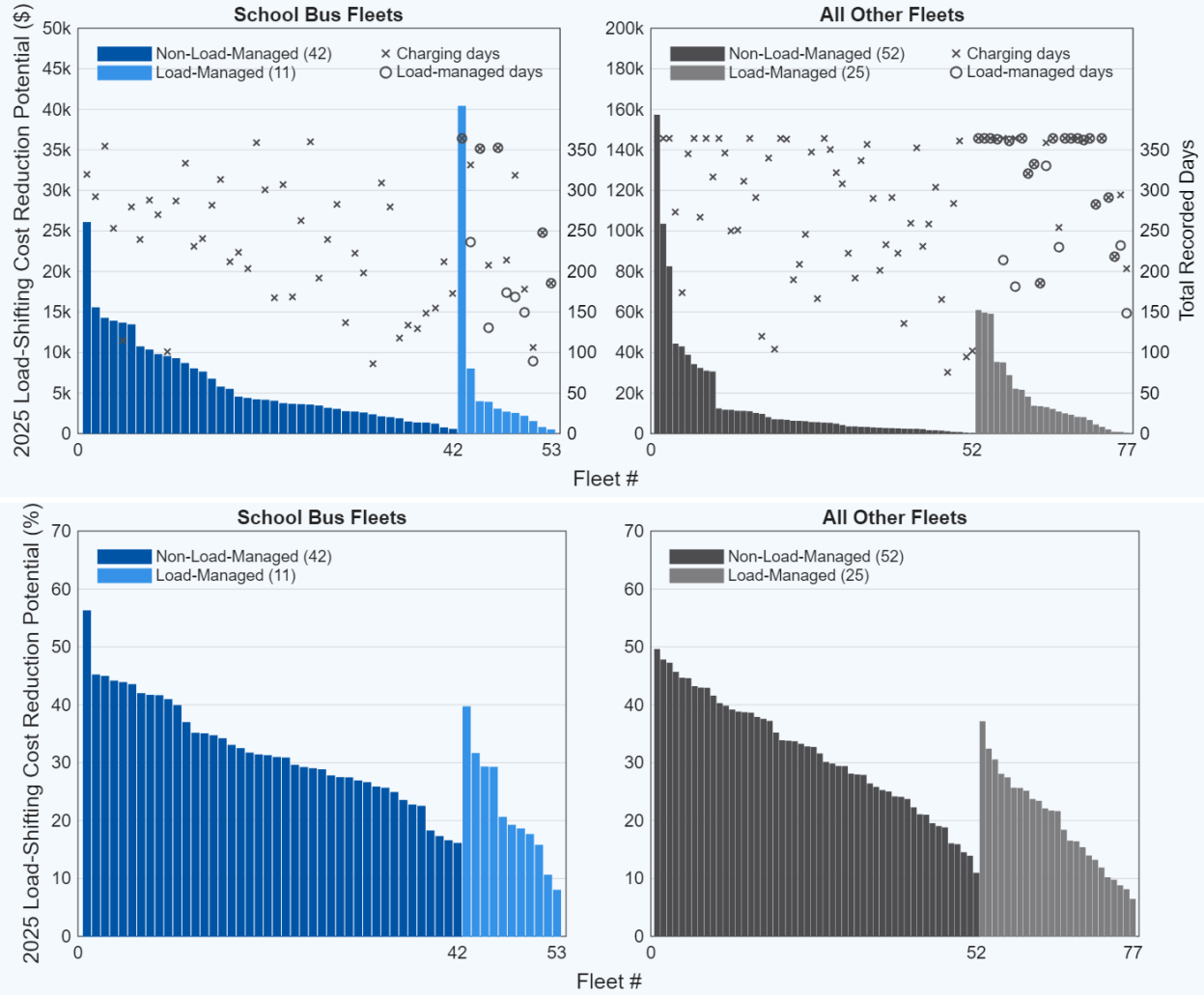
The Evaluation Team estimated the cost reduction potential of this daily load-shifting. Results of the analysis should be viewed with the following context:

- This analysis considers the volumetric (cost per kilowatt-hour) component of each site's electricity costs as well as any demand charges that may apply under the Utility's rate structure. Optimal load management has the potential to also reduce demand charge subscriptions, which could especially impact costs in lower-volume months. The cost-minimization approach developed in this analysis ensures that the monthly total cost (energy consumption plus demand charges) will be minimized. This allows for an increase in monthly peak demand so long as any applicable demand charges for increased demand are more than offset by TOU cost savings resulting from load-shifting to less expensive TOU time periods. In most cases, monthly peak demand stayed the same, having no impact on costs, or decreased, resulting in additional cost savings.
- These results reflect only the portion of the year in which each fleet operated vehicle charging stations and provided charging data; annualized projections of these cost reductions could be substantially higher for fleets that have less than a full year of charging data included in this analysis or that have not yet reached mature operations.
- These results reflect only the portion of each site's vehicle fleet that was electrified in EY2025. A fully electrified vehicle fleet would see higher cost reduction potential from load management.
- This analysis considers the cost-saving potential of load management, but it does not consider the potential of load management to generate revenue via LCFS Smart Charging credits.

- This analysis examined actual charging behavior at each site (using actual recorded plug-in and unplug times) to determine charging opportunities and does not account for other operational or scheduling improvements for charging electrified fleets, which could enable more-effective load management, resulting in higher potential cost reduction.

Figure 184 shows the cost reduction in total dollars that sites could have achieved in 2025 for each of the 130 sites the Team analyzed. Each bar represents the hypothetical savings by site if the site had used its charging flexibility to minimize electricity costs. The sites are segmented into load-managed and non-load-managed sites. The top graph shows the total dollar value of savings and the bottom graph shows the percentage savings.

Figure 184. PG&E EV Fleet Program Total Annual Cost Reduction Potential of Each Site with Use of Optimal Load Management



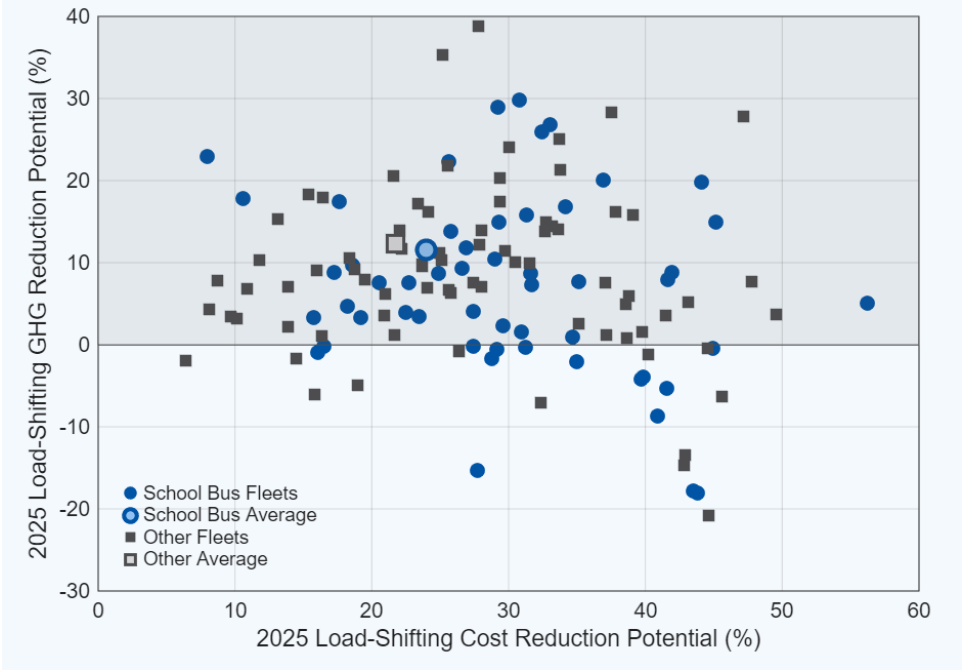
Each bar represents one site. Bar colors indicate the site's market sector, and bar shades show its use of load management.

Figure 184 provides several insights. The figure shows that even load-managed sites have the potential to save energy costs by better utilizing their charging flexibility. For example, as shown on the top graph, in 2025 sites that are already using load management have cost reduction potential of up to $40,000 in the school bus market sector and up to $60,000 for the largest sites in other market sectors. Many of these sites can capture additional savings by improving consistency of load management operations and better coordinating load management scheduling if their EVSP is capable and their operations allow.

Non-load-managed sites have cost reduction potential of up to $25,000 for school bus sites and up to nearly $160,000 for other market sectors. Sites that have the greatest potential savings are extremely large sites with high energy consumption and therefore higher overall costs. For example, the non-load-managed fleet with the almost $160,000 cost reduction potential represents an estimated 30% cost reduction potential—which is similar to many other fleets regardless of market sector.

Because lower-cost TOU periods often correspond to periods with lower carbon intensity for grid electricity, optimizing load management for energy cost savings can have a secondary effect of reducing the resulting carbon emissions from vehicle charging. Figure 185 shows estimated cost reductions and corresponding GHG emissions reductions for each site resulting from a cost-minimizing load-management strategy (considering carbon intensity only as a tiebreaking factor when there is sufficient charging flexibility). Across most sites, shifting charging load to reduce costs shows the potential to also reduce GHG emissions by more than 30% in some cases.

Figure 185. PG&E EV Fleet Program Potential Percentage Cost Reduction and Attributed GHG Emissions Reduction of Optimal Load Management, Cost Minimization



In addition to the cost-minimization load-shifting analysis, the Evaluation Team evaluated the maximum achievable reduction in GHG emissions with load shifting. To do this, the Team ran the load-shifting

optimization routine on the same data set with the objective of minimizing GHG emissions at each site. This approach maximizes the amount of charging that can take place during the middle of the day when the carbon intensity of grid electricity is the lowest, given that additional charging capacity and vehicle charging availability exists at each site. Figure 186 shows how the average charging load profile for the GHG-minimization approach compares with the cost-minimization and BAU average load profiles. Figure 187 displays the resulting combination of cost-reduction potential and emissions-reduction potential for each site when load shifting is employed to minimize GHG emissions.

Figure 186. PG&E EV Fleet Program Fraction of Daily EV Charging Load Occurring at Each 15-Minute Interval for the Average Day in this Analysis, BAU Compared with Cost-Minimization and GHG-Minimization

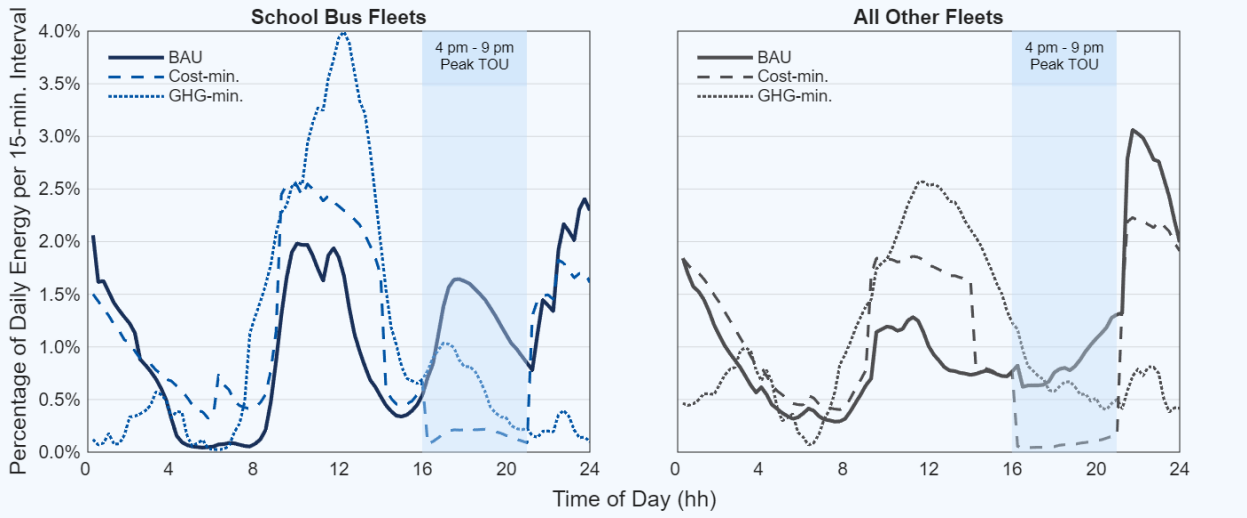


Figure 187. PG&E EV Fleet Program Potential Percentage Cost Reduction and Attributed GHG Emissions Reduction of Optimal Load Management, GHG-Minimization

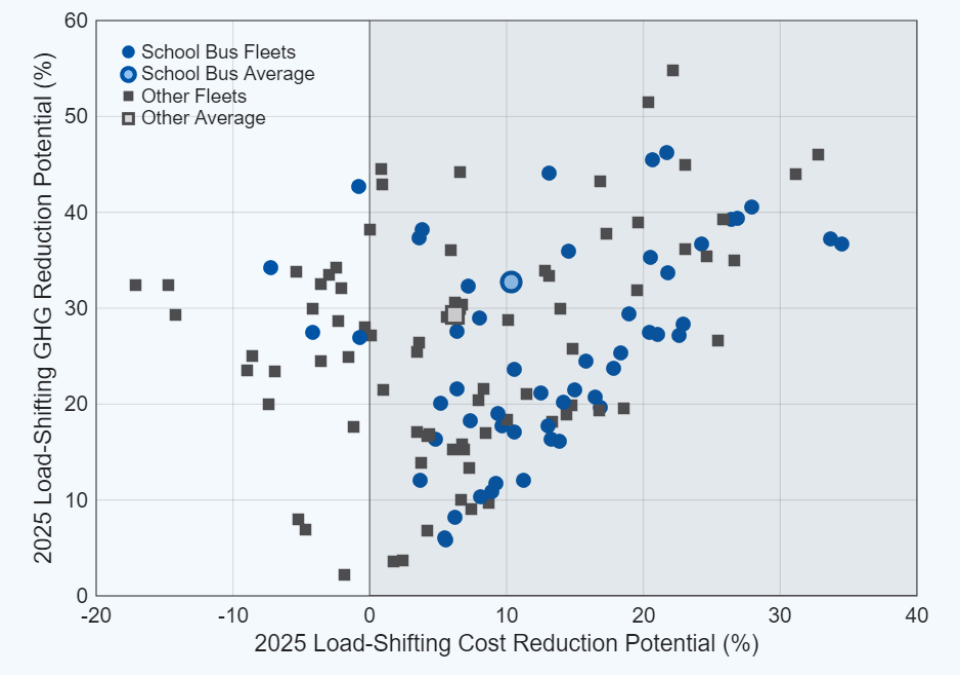


Table 69 aggregates these results across all sites included in the analysis. Overall, optimizing load shifting to minimize charging costs could reduce school bus sites' collective energy consumption costs by 24% and attributed electricity grid GHG emissions by 11.5%; for other market sectors, it could reduce energy consumption costs by 21.7% and attributed electricity grid GHG emissions by 12.4%. Load shifting to minimize GHG emissions could achieve GHG emissions reductions that are two to three times greater than with the cost-minimization approach (approximately 30%, on average, across all sites), but these reductions would come with lower cost savings (down to 7%).

Table 69. PG&E EV Fleet Program Summary of Potential Cost and Attributed GHG Emissions Reductions, Aggregated Across All Included Fleets

	School Bus Fleets	All Other Fleets	All Fleets Combined
2025 Total Number of Fleets	**53**	**77**	**130**
2025 Total Operating Days	**12,641**	**22,331**	**34,972**
Cost-minimization load-shifting			
Cost Reduction Potential ($)	325,336	1,254,428	1,579,764
GHG Reduction Potential (kg CO_2e)	87,487	442,582	530,069
Cost Reduction Potential (%)	24.0%	21.7%	22.1%
GHG Reduction Potential (%)	11.5%	12.4%	12.2%
GHG-minimization load-shifting			
Cost Reduction Potential ($)	140,129	359,974	500,103
GHG Reduction Potential (kg CO_2e)	249,204	1,048,081	1,297,285
Cost Reduction Potential (%)	10.3%	6.2%	7.0%
GHG Reduction Potential (%)	32.8%	29.3%	29.9%

Highlights

- Charging data indicate that most fleets have a significant opportunity to shift their charging energy use from between 4 p.m. and 9 p.m. to lower-cost time periods, including offsetting Friday evenings to Saturday mornings.
- Nearly half of the 2025 billing months for sites in the program to date average between $0.20/kWh to $0.30/kWh, and one-third of billing months average over $0.40/kWh. Almost 20% of billing months average over $0.50/kWh; or three times the lowest achievable cost of energy.
- Modeling based on charging flexibility suggests that significant demand from both load-managed and non-load-managed sites can be reduced at midday for school buses and around 9 p.m. for most fleets. This demand reduction and shifting of charging to lower cost periods would have resulted in average cost savings to the portfolio of 20% in 2025. Alternatively, if reducing GHG emissions were the priority, the portfolio could have reduced emissions by 30%, which may indicate opportunities for rate design and customer outreach.
- EY2021, EY2022 and EY2023 sites showed some tapering after initial growth, followed by steady operations after two years. EY2024 and EY2025 sites showed rapid growth throughout the year that is expected to continue.
- The number of consistent load-managed sites grew to 33 of 155 operational sites; Another nine sites showed intermittent use of load management, and nine others no longer appear to use load management.
- EY2025 sites added 26.6 MW of capacity, increasing total installed capacity to 92.6 MW, with maximum demand in EY2025 of nearly 19 MW.
- Two of 25 NSPs show excellent capability of load management, while another five to seven show light evidence, and the remaining 15 or so have not shown an ability to use load management.

Petroleum Displacement

The Evaluation Team estimated the petroleum displacement attributable to vehicle electrification enabled by PG&E's EV Fleet program. The Team used DGE for reporting purposes. However, because the transit bus market sector primarily uses CNG fuel, the Team converted transit bus natural gas consumption into DGE units based on the CNG fuel's energy content.

Table 70 presents petroleum displacement for the EV Fleet program through 2025, including estimated actual impacts for 2025, actual impact for all PTD sites, and a 10-year forecast for PTD sites. The results include the seven market sectors represented in the program, with the majority of petroleum reduction from PTD sites in the heavy-duty vehicle sector followed by the school bus sector. In 2025 the medium-duty vehicle sector had greater petroleum reduction than the school bus sector as a number of large sites with medium-duty fleets came online. The medium-duty vehicle sector is expected to produce the largest petroleum displacement of all market sectors over 10 years. In the program to date, the estimated usage of PTD sites is over 37 million electric miles, based on electricity consumption of 62,020 MWh. This translates to the displacement of over 5.7 million DGE.

Table 70. PG&E EV Fleet Program Petroleum Displacement Summary

Market Sector	Usage (n=155 [c])				Petroleum Displacement (DGE)		
	2025 Actual [a] kWh	PTD Actual [b] kWh	2025 Actual Use	PTD Actual Use	2025 Actual	PTD Actual	10-Year Projection
Forklift			26,668 hours	77,501 hours	51,942	149,666	377,120
Heavy-Duty Vehicle			5,862,629 miles	10,407,018 miles	1,007,029	1,836,969	8,115,178
Medium-Duty Vehicle			9,991,372 miles	13,729,925 miles	713,479	984,100	11,023,868
Port Cargo Truck			48,447 miles	219,556 miles	191,364	867,247	701,841
School Bus			4,442,183 miles	9,748,865 miles	485,428	1,067,957	3,883,444
Transit Bus			1,771,396 miles	3,663,036 miles	407,579	846,945	2,832,630
TRU			1,105 hours	3,938 hours	818	2,914	5,624
Total			**22,116,027 miles 27,773 hours**	**37,768,400 miles 81,439 hours**	**2,857,637**	**5,755,797**	**26,939,705**

[a] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.
[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.
[c] Only 155 of the activated sites had enough usage to be included in the impacts analysis.

Highlights

- All operational sites in 2025 collectively achieved an impact of more than 5.7 million gallons of petroleum displaced in the program to date.
- The heavy-duty vehicle sector contributed over 1.8 million gallons of displaced petroleum in 2025, and is projected to account for more than one-third of the petroleum displaced over 10 years.
- Over a 10-year period, the sites are expected to displace more than 26 million gallons of petroleum, with the largest contribution coming from the medium-duty vehicle sector.

Greenhouse Gas and Criteria Pollutant Impact

The Evaluation Team calculated reduced emissions from displaced fossil fuel use from ICE vehicles that were not in service because of the EV Fleet program. First, we developed ICE counterfactuals for each market sector, then the Team calculated the emissions associated with these vehicles under conditions that otherwise matched the EVs, which provided a baseline. Although EVs have no tailpipe emissions, the mix of generation sources from the electric grid includes renewable as well as fossil fuel power to supply electricity to the charging stations, with the latter primarily responsible for emitting GHGs and criteria pollutants into the atmosphere.

Table 71 shows GHG impacts estimates for the EV Fleet program for three time periods across market sectors: EY2025, the program to date, and a 10-year projection based on annualized data from all sites.

Table 71. PG&E EV Fleet Program GHG Reductions Summary

Market Sector	Usage (n=155 [c])				GHG Reduction (MT)		
	2025 Actual [a] kWh	PTD Actual [b] kWh	2025 Actual Use	PTD Actual Use	2025 Actual	PTD Actual	10-Year Projection
Forklift			26,668 hours	77,501 hours	251	712	1,873
Heavy-Duty Vehicle			5,862,629 miles	10,407,018 miles	8,589	15,218	72,979
Medium-Duty Vehicle			9,991,372 miles	13,729,925 miles	5,765	7,902	90,735
Port Cargo Truck			48,447 hours	219,556 hours	1,999	8,881	7,426
School Bus			4,442,183 miles	9,748,865 miles	4,310	9,158	36,199
Transit Bus			1,771,396 miles	3,663,036 miles	2,902	5,982	21,384
TRU			1,105 hours	3,938 hours	7	28	53
Total			22,067,580 miles 76,220 hours	37,548,844 miles 300,995 hours	23,823	47,880	230,649

[a] "2025 Actual" represents the data for EY2025 from all sites activated in the program to date.
[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.
[c] Only 155 of the activated sites had enough usage to be included in the impacts analysis.

Table 72 shows the estimated reductions in local emissions from the tailpipes of ICE vehicles that this program displaced, including hydrocarbons (HC) from off-road forklifts and heavy-duty vehicles. Port cargo trucks showed the highest reduction in ROG emissions due to the poor emissions performance of conventional port cargo trucks. Transit buses showed the greatest reduction in CO, driven by the assumption that displaced transit buses run on CNG.

Table 72. PG&E EV Fleet Program Local Emissions Reductions, PTD Actual Sites

Market Sector	PTD Actual [a] (n=155 [b])				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Forklift	1,359.7	57.1	43.5	1,251.6	139,365.6
Heavy-Duty Vehicle	226.0	135.8	129.3	677.4	79,900.4
Medium-Duty Vehicle	-	23.1	21.8	178.9	5,905.3
Port Cargo Truck	3,234.9	228.6	210.4	3,914.2	22,872.0
School Bus	-	22.5	21.5	99.6	2,831.4
Transit Bus	-	2.3	2.2	206.4	163,301.6
TRU	13.6	1.1	1.0	124.7	14.9
Total	4,834.1	470.4	429.6	6,452.8	414,191.2

[a] "PTD Actual" represents the data from all activated sites from program inception for all program years.
[b] Only 155 of the activated sites had enough usage to be included in the impacts analysis.

Table 73 shows the same information as above for only EY2025. These are the localized emissions reductions that occurred based on actual fleet operations over the past year.

Table 73. PG&E EV Fleet Program Local Emissions Reductions, 2025 Actual Sites

Market Sector	2025 Actual [a] (n=155 [b])				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Forklift	530.8	19.4	14.7	488.4	57,360.0
Heavy-Duty Vehicle	126.4	82.4	78.5	390.0	37,604.5
Medium-Duty Vehicle	-	16.8	15.9	125.4	4,224.6
Port Cargo Truck	713.8	50.4	46.4	863.7	5,046.9
School Bus	-	10.3	9.9	45.7	1,296.2
Transit Bus	-	1.0	1.0	101.8	80,466.9
TRU	4.9	0.3	0.3	48.2	5.4
Total	1,375.9	180.7	166.6	2,063.2	186,004.5

[a] "2025 Actual" represents the data for EY2025 from all sites activated in the program to date.
[b] Only 155 of the activated sites had enough usage to be included in the impacts analysis.

Table 74 provides an estimate of savings over the next 10 years. These are the annualized reductions from all PTD sites extended over a decade. The table shows that forklift sites account for over one-third of total ROG emissions reductions and almost half of CO emissions reductions, despite accounting for less than 2% of total electricity use. This is a result of the substantially better emissions performance of electric forklifts compared with conventional forklifts. Forklifts also account for well over half of hydrocarbon emissions reductions, largely due to the fact that modern on-road conventional vehicles have already eliminated these emissions. However, heavy-duty vehicles account for almost 60% of PM emissions reductions.

Table 74. PG&E EV Fleet Program Local Emissions Reductions, 10 Year Projected Impact for PTD Sites

Market Sector	PTD Sites 10-Year Projected Impact (n=155 [a])				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Forklift	6,554.6	140.8	106.5	6,030.6	835,381.9
Heavy-Duty Vehicle	909.9	934.9	892.1	3,407.5	240,367.3
Medium-Duty Vehicle	-	295.0	276.9	3,186.9	114,952.8
Port Cargo Truck	2,617.9	184.9	170.2	3,167.6	18,509.7
School Bus	-	92.7	88.7	403.1	11,031.0
Transit Bus	-	8.2	7.8	711.6	559,878.2
TRU	49.9	2.9	2.7	492.2	55.6
Total	10,132.3	1,659.5	1,545.0	17,399.6	1,780,176.5

[a] Only 155 of the activated sites had enough usage to be included in the impacts analysis.

Table 75 shows counterfactual vehicle GHG emissions, emissions from the electricity used to charge the EVs, and GHG emissions reductions and percentage changes. Table 76 shows the net reductions of NO_X emissions from using EVs, based on the counterfactual and Utility emissions. The Evaluation Team estimated a total annualized GHG reduction of 80% and an NO_X reduction of 48% from the use of EVs instead of counterfactual vehicles for EY2025 sites. Annualized NO_X reduction for EY2025 sites is lower this year (48%) than in previous years, because several medium-duty vehicle EY2025 sites that account for a significant share of overall EY2025 vehicles have gasoline instead of diesel counterfactuals, yielding only an 11% reduction. Class 2b and Class 3 pickup trucks and vans have gasoline counterfactuals, whereas

Class 4 through Class 7 trucks have diesel counterfactuals. Reviewing the data for the program to date reveals an estimated 82% actual reduction in GHG emissions and 78% reduction in NO_X emissions across all market sectors.

Table 75. PG&E EV Fleet Program Counterfactual GHG Reductions

Market Sector	EY2025 Sites (n=51 [a]) Annualized GHG (MT)				PTD Sites (n=155 [b]) GHG (MT)			
	Counter factual	Utility	Reduction	% GHG Reduction	Counter factual	Utility	Reduction	% GHG Reduction
Forklift	6.4	0.6	5.8	91%	820.7	108.9	711.9	87%
Heavy-Duty Vehicle	1,019.1	202.6	816.6	80%	18,758.6	3,540.9	15,217.6	81%
Medium-Duty Vehicle	5,628.2	1,194.2	4,434.0	79%	9,815.5	1,913.8	7,901.7	81%
Port Cargo Truck	45.4	4.8	40.6	89%	9,942.4	1,061.2	8,881.1	89%
School Bus	1,158.8	161.2	997.6	86%	11,298.6	2,140.6	9,157.9	81%
Transit Bus	699.2	130.9	568.3	81%	7,405.4	1,423.2	5,982.2	81%
TRU	-	-	-	None	32.6	5.0	27.6	85%
Total	8,557.1	1,694.2	6,862.9	80%	58,073.8	10,193.7	47,880.0	82%

[a] Only 51 of the EY2025 activated sites had enough usage to be included in the impacts analysis

[b] Only 155 of the PTD activated sites had enough usage to be included in the impacts analysis

Table 76. PG&E EV Fleet Program Counterfactual NO_X Reductions

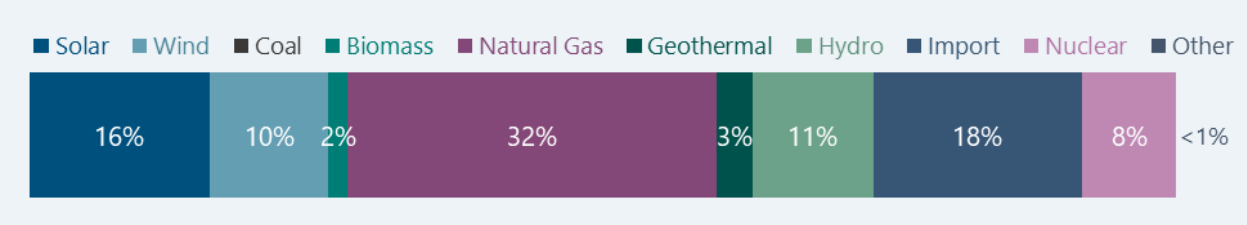
Market Sector	EY2025 Sites (n=51 [a]) Annualized NO_X (kg)				PTD Sites (n=155 [b]) NO_x (kg)			
	Counter factual	Utility	Reduction	% NO_X Reduction	Counter factual	Utility	Reduction	% NO_X Reduction
Forklift	17	0	17	97%	3,102.6	92.4	3,010.2	97%
Heavy-Duty Vehicle	829	164	665	80%	15,343.8	2,876.2	12,467.6	81%
Medium-Duty Vehicle	1,077	956	121	11%	6,597.4	1,540.0	5,057.5	77%
Port Cargo Truck	11	4	8	66%	2,508.2	922.2	1,585.9	63%
School Bus	653	132	520	80%	10,139.1	1,782.1	8,357.0	82%
Transit Bus	33	105	(73)	None	375.5	1,143.8	(768.3)	None
TRU	-	-	-	None	138.2	4.1	134.1	97%
Total	2,620.0	1,361.9	1,258.1	48%	38,204.7	8,360.7	29,844.0	78%

[a] Only 51 of the EY2025 activated sites had enough usage to be included in the impacts analysis.

[b] Only 155 of the PTD activated sites had enough usage to be included in the impacts analysis.

Figure 188 shows the program net electricity generation mix during the hours that EVs were charging. The CAISO grid mix continually changes depending on factors such as the level of total demand for power on the grid and the availability of fossil generation and variable renewable resources such as solar.

Figure 188. PG&E EV Fleet Program Net Electricity Mix, PTD Sites



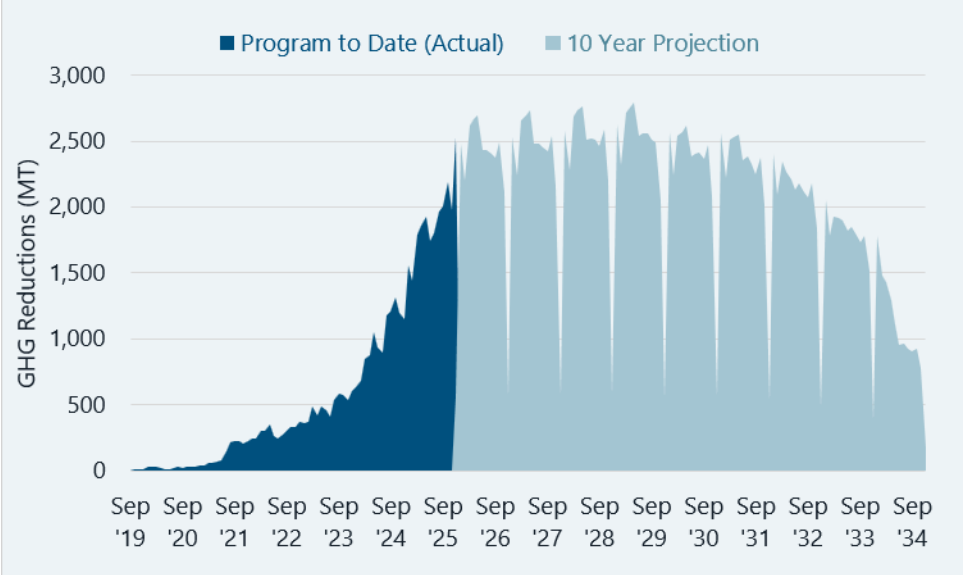
The data indicates that EVs were generally not charging during peak hours of solar output when grid emissions were the lowest. Approximately 18% of the grid mix comprises electricity imports, which do not vary by time of day for analysis purposes but match the resource mix purchased for the California grid.[90]

Based on the real-time grid conditions when EV charging occurred, the overall energy mix was about 50% zero-emission or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 32% natural gas. Emissions reductions from these sites should increase over 10 years as the grid becomes cleaner. Additionally, the increased use of managed charging will reduce emissions as more EVs charge during off-peak times and times when the grid is supplied with more renewable resources such as solar. Emissions will further decrease as more charging sites and EVs are added in future evaluation years. The *Electricity Cost and Emissions Optimization Analysis* section in the earlier grid impacts analysis explains how fleets could change their charging timing to further reduce the GHG of their electricity consumption and improve price performance.

Figure 189 shows how program GHG reductions have increased to date as a result of the EV Fleet program and how these reductions are expected to grow over time for all activated sites. The analysis period ranges from the date of activation for the first site in the program through the end of EY2025. The analysis incorporates the net reduction (counterfactual emissions minus Utility emissions) for each fleet within the PG&E EV Fleet program. Emissions reductions appear in dark blue, and anticipated benefits based on annualization appear in a lighter blue. Because sites begin operations at different times, the 10-year sunset for each site appears as a gradual tapering of program benefits between 2030 and 2033. This taper reflects that benefits are no longer counted after 10 years, although fleets will likely continue to use the infrastructure. While each year's operations appear similar over the next five years, several key factors are driving the variation. These include seasonality of Utility generation sources (high Utility emissions will appear as a dip on the curves), holidays occurring on weekends versus weekdays, and inaccuracies in predicted operations for sites that became operational late in 2025.

[90] The power associated with imports comes from a mixture of renewables, hydro, nuclear, and natural gas power plants located outside of California (www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation).

Figure 189. PG&E EV Fleet Program Historical and Forecasted GHG Reductions for PTD Sites



Highlights

- Results for the EV Fleet program to date show an 82% reduction of GHGs and a 78% reduction in NO_X emissions.
- The greatest reduction in local emissions was for CO, with more than 186,000 kg in 2025 and a projected 10-year reduction of more than 1,780,000 kg.
- Based on the real-time grid conditions when EV charging occurred, the overall energy mix contained about 50% zero-emission or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 32% natural gas.

Health Impacts

The Evaluation Team calculated public health impacts (as benefits and costs) of reductions in criteria pollutants from vehicle electrification. The pollutants included in the analysis are primary $PM_{2.5}$ and precursors of secondary $PM_{2.5}$, including NO_X, SO_2, NH_3, and VOCs. This analysis considered only tailpipe emissions reductions rather than full lifecycle emissions (such as power plant emissions). The Evaluation Team used the EPA COBRA to evaluate the health benefits associated with emissions reductions. COBRA estimates the county-level monetized benefits for the county where emissions are reduced. The tool also estimates monetized benefits for all counties in the United States (since emissions disperse beyond the source county), although most impacts are felt in nearby counties and the Team's analysis examines only California counties.

The morbidity-related monetary benefits include avoided lost wages, avoided medical costs, and the money people are willing to pay to avoid an illness or condition, such as a respiratory disease. The monetary benefits associated with mortality are measured by the value of a statistical life associated with

premature mortality. COBRA reports both a low and a high impact for mortality, representing the uncertainties in the estimates.

The total value of the health benefits associated with emissions reductions from the EV Fleet program for activated PTD sites is between $4,070,682 and $5,421,073. Table 77 shows the health benefits in California broken down by health endpoint.

Table 77. PG&E EV Fleet Program California Health Benefits for PTD Sites in 2025

Health Endpoint	Change in Incidence (Annual Cases)		Monetary Value (Annual, 2025 Dollars)	
	Low	High	Low	High
Mortality	**0.237**	**0.327**	**$3,567,859**	**$4,918,250**
Avoided Medical Care				
Hospitalization, Respiratory	0.024	0.024	$451	$451
Hospitalization, Cardiovascular	0.011	0.011	$332	$332
Hospitalization, Other	0.032	0.032	$747	$747
ER Visits, Respiratory	0.53	0.53	$884	$884
ER Visits, Cardiovascular	0.023	0.023	$51	$51
Out of Hospital Heart Attacks	0.001	0.001	$87	$87
Nonfatal Heart Attacks	0.054	0.054	$4,720	$4,720
Stroke	0.005	0.005	$348	$348
Lung Cancer	0.007	0.007	$297	$297
Asthma	271.325	271.325	$225,790	$225,790
Hay Fever	11.066	11.066	$12,699	$12,699
Lost Productivity				
Minor Restricted Activity Days	78.029	78.029	$10,104	$10,104
Work Loss Days	13.272	13.272	$4,324	$4,324
School Loss Days	138.337	138.337	$241,988	$241,988
Total Health Effects	-	-	$4,070,682	$5,421,073

At the site level, four market sectors accounted for 98% of the monetary value from benefits. The heavy-duty vehicle market sector had the highest health benefits overall (47%), followed by the school bus (22%), medium-duty vehicle (21%), and forklift (9%) market sectors.

As part of this analysis, the Evaluation Team also examined health benefits within DACs, which may be disproportionately burdened by sources of pollution (including air pollution from ICE vehicles). Because COBRA estimates effects at only the county level, the Evaluation Team disaggregated health benefits by census tract using the relative population of each tract from the most recent ACS. For example, we allocated 10% of the value of the health benefits to a census tract with 10% of the county's population. The Evaluation Team then estimated the total benefits allocated to DACs and non-DACs.[91] This approach

[91] DAC census tracts are defined as those included in the SB 535 Disadvantaged Communities List (2022), which includes DAC categories for CalEnviroScreen 4.0 Top 25%, CalEnviroScreen 4.0 High Pollution Burden Score and Low Population Count, and 2017 Disadvantaged Community (CalEnviroScreen 3.0 only).

assumes that the benefits of emissions reductions are distributed evenly throughout the county. If the sites reside in DACs, and the emissions reductions are greater in the tracts near the sites, this approach understates the potential benefit to DACs. Additional information about emissions dispersion within counties would provide more precise estimates of health benefits to DACs and non-DACs.

The largest portion of health benefits were in Alameda County, which had 11% of the total benefits, followed by Santa Clara County (11%), Sacramento County (10%), Contra Costa County (8%), and San Joaquin County (8%). Overall, 18% of the total benefits are in DACs.

Highlights

- Cumulative health impact estimates for California counties realized by the electrification of EV Fleet program sites in terms of monetary benefits range from $4,070,682 to $5,421,073.
- The heavy-duty vehicle market sector had the highest health benefits overall (47%), followed by the school bus (22%), medium-duty vehicle (21%), and forklift (9%) market sectors.
- The largest portion of health benefits were in Alameda County, which had 11% of the total benefits, followed by Santa Clara County (11%), Sacramento County (10%), Contra Costa County (8%), and San Joaquin County (8%).
- Overall, 18% of the health benefits are in DACs

Net Impacts

As part of the net impacts analysis, the Evaluation Team estimated program effects on participants to exclude impacts from actions that participants would have taken without the program (freeridership) and to include any program-attributable indirect impacts on participants (participant spillover).

Enhanced Self-Report

The Evaluation Team based our approach for the MDHD program's enhanced self-report NTG analysis on information we obtained as part of in-depth surveys with participating fleet managers. The Evaluation Team created the survey via an online survey platform, Qualtrics, and provided a link to the survey during or following site visits that the Team conducted. The Evaluation Team used the CPUC nonresidential customer self-report NTG framework originally developed for energy efficiency programs as the base for the MDHD fleet manager NTG methodology approach.[92] *Appendix B* provides more detail about the MDHD fleet manager self-report NTG methodology.

The Evaluation Team estimated the core component of the CPUC NTG methodology through three separate PAI site scores (PAI-1A, PAI-2, and PAI-3). The Team used three separate sets of questions to assess the three components of the core NTG ratio, with each PAI score on a scale of 0.0 to 1.0 representing a different way of characterizing the PG&E EV Fleet program influence. The analysis included

[92] California Public Utilities Commission, Energy Division. February 20, 2015. Methodological Framework for Using the Self-Report Approach to Estimating Net-to-Gross Ratios for Nonresidential Customers.

fleet manager responses from 14 of the 39 participating sites that were provided with a link to the survey.[93]

The Evaluation Team calculated the resulting self-report NTG for each site, prior to accounting for participant spillover, as the average of the PAI score values. The average PAI scores across all sites surveyed resulted in an overall core NTG ratio of 0.60, presented in Table 78. One minus the overall core NTG ratio of 0.60 equals the 0.40 freeridership ratio for the EV Fleet program.

None of the surveyed sites reported electrifying more of their fleet since participating in the EV Fleet program, without the benefit of funding from the program or another organization and where their PG&E program participation was important in the additional purchasing decision. Therefore, the participant spillover analysis found that the participant spillover ratio is 0.00. The final program-level NTG ratio of 0.60 for the PG&E EV Feet program sites surveyed equals one minus the freeridership ratio plus the participant spillover ratio presented in Table 78. The EY2025 NTG ratio of 0.60 (n=14) is higher than the EY2024 NTG ratio of 0.51 (n=11) and the EY2023 NTG ratio of 0.48 (n=4), indicating the EV Fleet program had more influence on the surveyed EY2025 fleets' decision to complete the transportation electrification projects compared with the surveyed fleets in EY2024 and EY2023.

Table 78. PG&E EV Fleet Program NTG Fleet Manager Analysis Results in EY2025

Fleet Manager Survey Completes [a]	Average of PAI-1A Score NTG	Average of PAI-2 Score NTG	Average of PAI-3 Score NTG	Core NTG Ratio	Freeridership Ratio	Participant Spillover Ratio	Final NTG Ratio
14	0.77	0.44	0.58	0.60	0.40	0.00	0.60

[a] The survey results are based on a low respondent count, which limits the reliability of the findings and precludes statistical significance; therefore, results should be viewed as indicative rather than conclusive.

Highlights

- The EY2025 program-level freeridership ratio is 0.40 with a 0.00 participant spillover ratio, which resulted in a program-level NTG ratio of 0.60.
- The EY2025 NTG ratio of 0.60 (n=14) is higher than the EY2024 NTG ratio of 0.51 (n=11) and the EY2023 NTG ratio of 0.48 (n=4), indicating that the EV Fleet program had more influence on the surveyed fleets' decisions to complete the transportation electrification projects in EY2025 than in EY2024 and EY2023.

5.1.3. Lessons Learned

Continued uncertainty about when, if, and how new regulations would go into effect made planning for increases or decreases in customer interest and potential applications difficult for PG&E program staff in 2025. As in previous evaluation years, regulatory uncertainty and market

[93] Respondents from five school bus sites, two transit bus sites, two forklift sites, two heavy-duty vehicle sites, one medium-duty vehicle site, one distribution site, and one EV tractor site completed the survey.

pressures remained significant barriers for both PG&E staff and customers. Several new developments added complexity to an already difficult operating environment.

- **Diminished compliance requirements:** CARB's withdrawal of the ACF waiver in January 2025 accelerated a trend of private-sector customers who had been motivated by compliance requirements stepping back from electrification commitments, leading to some project cancellations.
- **Tariffs and procurement uncertainty:** For some customers, new federal tariffs created uncertainty around the cost and availability of components sourced from outside the United States, making project planning more challenging.

Through these changes, many of PG&E's target customers, including schools, municipalities, and state agencies, stayed engaged in the program. PG&E staff worked with customers in 2025 to help them understand and navigate new obligations and project risks as more regulations and programs entered the market to support electrification.

PG&E staff remained focused on adapting program operations in response to challenges that had emerged in prior program years. In 2025, staff adjusted the transit budget goal based on program conditions and refined their approach to load management outreach. To support the program's goal of directing 15% of its infrastructure budget to public transit projects, PG&E staff customized marketing efforts for transit agencies, and beginning in July 2025, established a waitlist for non-transit applicants. However, after determining that the 15% target was not achievable by the application deadline, staff filed an Advice Letter with the CPUC in December 2025 to reduce the transit budget requirement to 10%.

In addition, to improve load management, the PG&E EV Advisory Services team conducted outreach through the EVAS program to activated EV fleet sites with high on-peak charging. The goal was to identify where efforts to change these fleets' behavior could have the greatest impact. Although engaging sites to adopt load management improvements remained challenging, the effort gave staff a clearer understanding of which sites would benefit most from additional support.

Overall, the program maintained strong enrollment, with 393 contracts executed and schools and municipalities continuing to represent a significant share of program participation.

The EV Fleet program sites continue to help displace petroleum, reduce GHG and local emissions, and provide health impacts. The EV Fleet program sites have displaced nearly six million gallons of petroleum in the program to date, with the heavy-duty vehicle market sector contributing nearly two million gallons. In addition, the program sites have resulted in a reduction of 47,880 MT of GHGs to date. These sites have all positively contributed to lowering local emissions, with CO reduction being the most prominent, achieving a reduction of 414,191 kg to date. Overall, 18% of the health benefits from emissions reductions are in DACs, and the total monetized health benefits from sites range from $4,070,682 to $5,421,073.

Fleet managers remain motivated to participate in the program and report meaningful benefits, but costs continue to be a concern even among program participants who are satisfied with their overall experience. As in previous years, interviewed fleet managers said they were motivated to

participate in the EV Fleet program primarily by environmental benefits (9 of 13), and available rebates and incentives for charging infrastructure (11 of 13), and vehicles (9 of 13). Respondents reported two types of costs: charging infrastructure and vehicle purchase costs as barriers before program participation (9 and 8, respectively) but fewer reported these barriers after participating.

Fleet managers reported several financial and community-related benefits. All respondents (13 of 13) said they expected the transition to electrification to benefit their fleet or community. Fleet managers cited community benefits, in particular reducing noise pollution (4 of 9) and improved air quality (5 of 9). Fleet managers were divided on changes in fueling costs, with six reporting lower fuel costs and seven higher fuel costs. Finally, nearly all fleet managers (9 of 10) indicated that they were either *very satisfied* or *somewhat satisfied* with their overall program experience.

Smaller sites representing a diverse portfolio of market sectors came online in 2025, leading to decreased costs per site, but increased costs per vehicle, and per installed kilowatt. A mix of smaller sites across five market sectors came online in EY2025 leading to an average of 660 kW of installed capacity per site through 2025, compared with 765 kW through 2024. Looking at EY2025 financially closed out sites only, average installed capacity decreased by 57% to 559 kW compared with 1,310 kW in EY2024. The average Utility infrastructure cost including TTM and BTM was $275,712 per site in the program to date, which is significantly less than costs of $331,005 per site in the program through 2024. The average Utility infrastructure cost was $34,409 per vehicle and $1,317 per installed kilowatt through 2025, compared with $24,931 per vehicle and $1,508 per kilowatt installed through 2024. All-in costs paid by the customer and PG&E vary widely between sites, with an average of $810,420 per site in the program to date. While the school bus market sector continues to make up over 43% of all closed out sites, over one-quarter of sites are from the medium-duty vehicle market sector.

Site activation timelines decreased slightly year over year. The overall median number of calendar days from application to activation was 840 in EY2025, which is lower than the median in EY2024 of 989 days. The design and permitting phase has been the longest in duration across all evaluation years, taking 528 days in EY2025, down from 634 days in EY2024. Other program phases remained similar in length to those in EY2024.

The lower median number of days to activation for sites in the EV Fleet program may be attributable to overall program maturity and associated efficiency and to smaller average project sizes in EY2025 than in EY2024. Each of five market sectors had at least four new sites activated in EY2025, including forklift (4), heavy-duty vehicle (4), medium-duty vehicle (20), school bus (26) and transit bus (6), with an average size of 487 kW in EY2025, compared with 900 kW in EY2024.

The EV Fleet program is on pace to achieve its new total site and vehicle goals. In EY2025, 60 sites with 1,311 charging ports were activated supporting 1,644 vehicles, based on VAPs of activated sites. Six market sectors are supported by the program, with school bus sites showing the highest participation in EY2025 (51% of sites). The 393 contracts signed in the EV Fleet program to date could support 7,270 MDHD vehicles, which would exceed the program's site and vehicle goals. PG&E staff have intentionally focused on smaller sites to reduce overall costs and help the program reach its site goal.

Overall program spending remains low, though spending in DACs continues to remain above target. PG&E spent $19.2 million of the EV Fleet program budget in 2025, bringing total spending to $89.4 million of the $236.3 million approved program budget, or 38% of available funding. The total spending does not include funding reserved for contracted sites that have not yet been installed. The cumulative percentage of spending in DACs in the program to date is 42%, which exceeds the program's per se reasonableness goal of 25%.

Overall consumption increased significantly in 2025, though peak demand only represents a small portion of installed charging capacity. A total of 26.6 MW of new charging capacity was activated in the EV Fleet program in EY2025, bringing total capacity for the PTD sites to 92.6 MW. Overall consumption in EY2025 was 32.7 MWh, almost double EY2024 consumption of 16.6 MWh. Peak demand reached 18.8 MW in EY2025, a 35% increase over a peak of 11.7 MW in EY2024. On peak energy consumption was 14% of all energy consumed in EY2025, slightly lower than 16% in EY2024 and 17% in the program to date.

A small but increasing number of fleets are using load management and a significant opportunity remains for fleets to reduce costs and GHG emissions. The number of load-managed sites grew from 18 of 108 operational sites (17%) in EY2024 to 33 of 159 (20%), the highest percentage across MDHD programs. On a monthly basis, 71% of medium-duty vehicle charging, 49% of transit bus charging, 46% of school bus charging, and 41% of heavy-duty vehicle charging sessions have enough flexibility to be shifted to lower cost and lower emissions time periods using load management, representing cost savings of 20% across program sites. Notably, 62% of all medium-duty vehicle charging sessions have enough flexibility to shift all on-peak charging to off-peak periods without impacting operations.

Potential savings through use of load management are as high as $160,000 per site annually for non-load-managed sites, and $60,000 for sites already using load management through optimization. On average, sites can reduce GHG emissions by 21.7% by avoiding consumption from 4 p.m. to 9 p.m., with some sites reaching reductions of more than 30% if charging is optimized to avoid consumption during periods when grid emissions are highest.

Not all NSPs offer load management capability; only two of 25 NSPs operating in the EV Fleet program have customers that consistently use load management, and an additional seven show signs of inconsistent usage. Although most fleet operators were aware of TOU pricing, not all of these operators have direct access to their utility bills to understand TOU cost impacts. During site visits the Team observed that most operators expected their average electricity costs to be lower than the actual cost data presented by the Evaluation Team.

The best results in the EV Fleet program appear to show monthly billing costs between $0.10/kWh and $0.20/kWh through use of load management, and two thirds of all billing months have average costs of less than $0.30/kWh, which is the lowest across the MDHD programs. Almost 20% of sites have billing months across the program with average electricity costs greater than $0.50/kWh, and almost 7% have costs of $1.00/kWh or more. However, many of the billing months greater than $1.00 are from sites with very low usage, and therefore monthly fees are spread across a small number of kilowatt-hours. Overall, larger sites tend to have lower electricity costs, both because of load management and because monthly fees are spread across a larger number of kilowatt-hours.

5.2. Schools and Parks Pilots

5.2.1. Overview

This overview provides a detailed description of the PG&E EV Charge Schools and Parks Pilots; summaries of the Pilots' implementation process, performance metrics, program materials and budget; and a timeline of major milestones. Following the overview are detailed findings, highlights, and lessons learned.

Pilot Description

EV Charge Schools Pilot: Through its EV Charge Schools Pilot, PG&E offered direct installation of and incentives for installing four or six L2 charging ports at K–12 schools within its service territory. The pilot was designed to provide L2 charging infrastructure at schools and educational facilities in support of California's electrification goals. In the original Decision 19-11-017, PG&E projected installing these chargers across 22 sites.[94] While PG&E built and maintained the EV service connection and supplied infrastructure for all sites, the equipment could be owned by either PG&E or the site host. For sites where PG&E owned the equipment, the site worked with a preapproved EVSP to help manage equipment operations. If the site host chose to own the equipment, PG&E provided a rebate of up to $11,500 (L2 single) or $15,500 (L2 dual) for the charger purchase. In all cases, the site host was required to enroll in a TOU rate. PG&E also provided educational materials to promote awareness of the newly installed EVSE and benefits of EVs.

EV Charge Schools Pilot Design Goal

Offer L2 charging infrastructure at schools and educational facilities.

EV Charge Schools Pilot Targets

- Four or six L2 ports at each site
- 22 schools

EV Charge Parks Pilot: Through its EV Charge Parks Pilot, PG&E offers direct installation of L2 chargers and DCFCs in state parks and beaches within its service territory. PG&E staff designed the Pilot to enable staff at state parks and beaches to charge the EVs in their own fleet and for staff and patrons to charge LDVs. In Decision 19-11-017, PG&E projected two standard site designs: one with four L2 charging ports at three locations and one with two L2 ports and two DCFC ports at two locations. Per the Decision, PG&E expected to offer off-grid charging at six sites that have sufficient capacity to support charging but where the cost of upgrading the existing electric infrastructure would be prohibitive given the distance of the electric infrastructure from the site locations. For all sites, the contracted third-party EVSP will own the chargers and serve as

EV Charge Parks Pilot Design Goal

Encourage state parks and beaches to charge their own EV fleets and to offer charging to staff and patrons with LDVs.

EV Charge Parks Pilot Targets

- 40 L2 and 3 DCFC ports
- 15 state parks and beaches

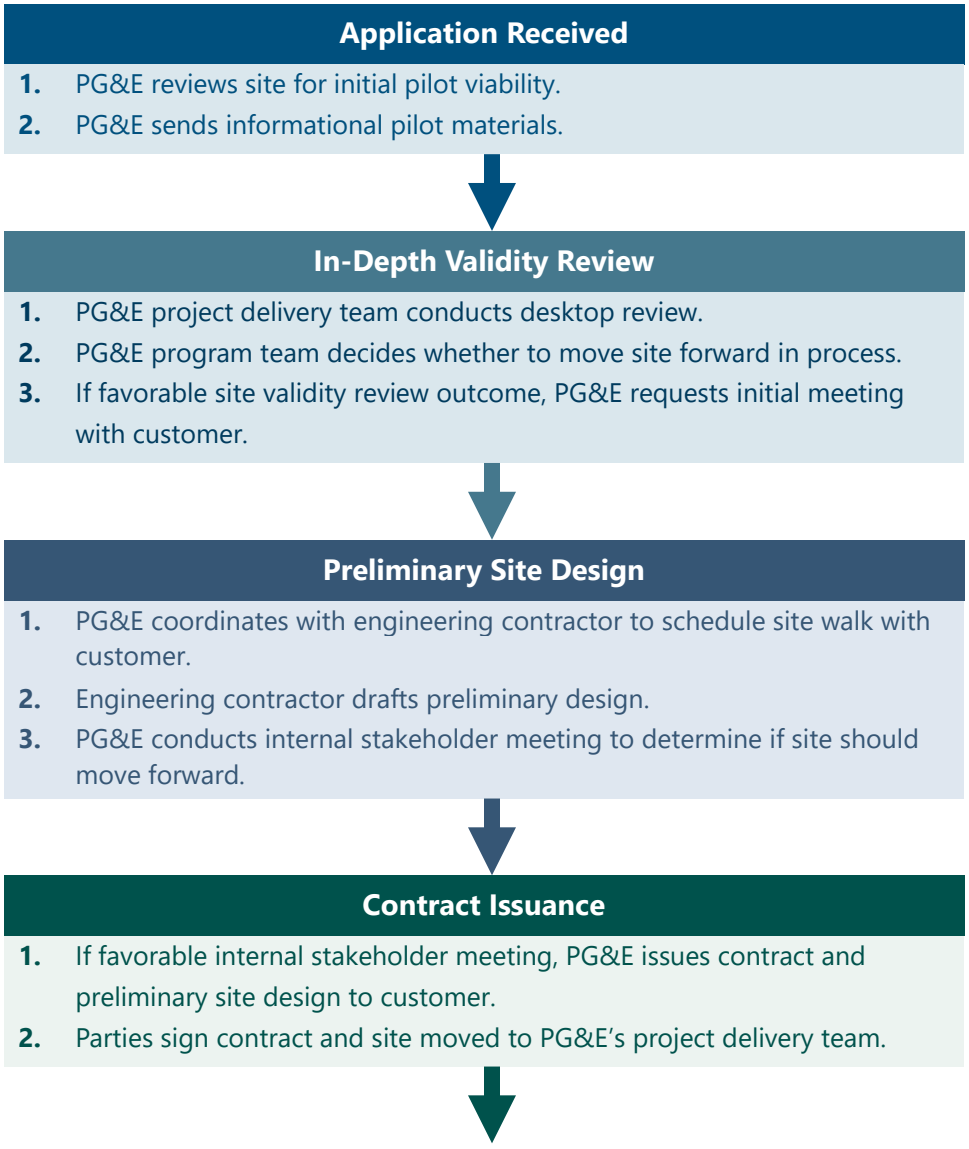
[94] In the EY2023 and EY2024 closeout interviews, PG&E staff reported that although PG&E would not achieve the 22-site goal, it is installing more ports than expected and will still reach the port goal of 88 to 132 ports; there was no formal regulatory filing to change the Schools Pilot goals.

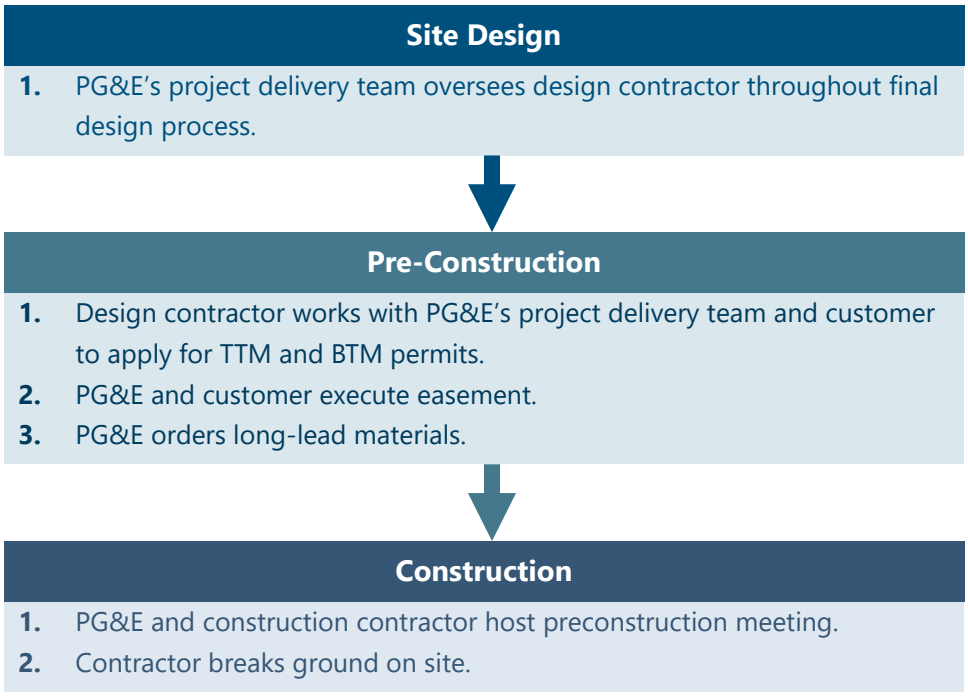
the customer of record, maintain the equipment, and manage the charger electricity costs, as approved by the CPUC in AL 7652-E. PG&E is also required to post educational signs around the chargers to raise awareness among park and beach patrons that they can charge EVs at state park and beach locations across the state.

Implementation

As interested customers became aware of the EV Charge Schools Pilot—through PG&E marketing efforts, solicitations from EVSPs, word-of-mouth, or directly from a PG&E account manager—they could choose to apply as the first step in the implementation process. Figure 190 provides details on the process of taking a site from application to construction for the EV Charge Schools Pilot.

Figure 190. PG&E EV Charge Schools Pilot Implementation Process

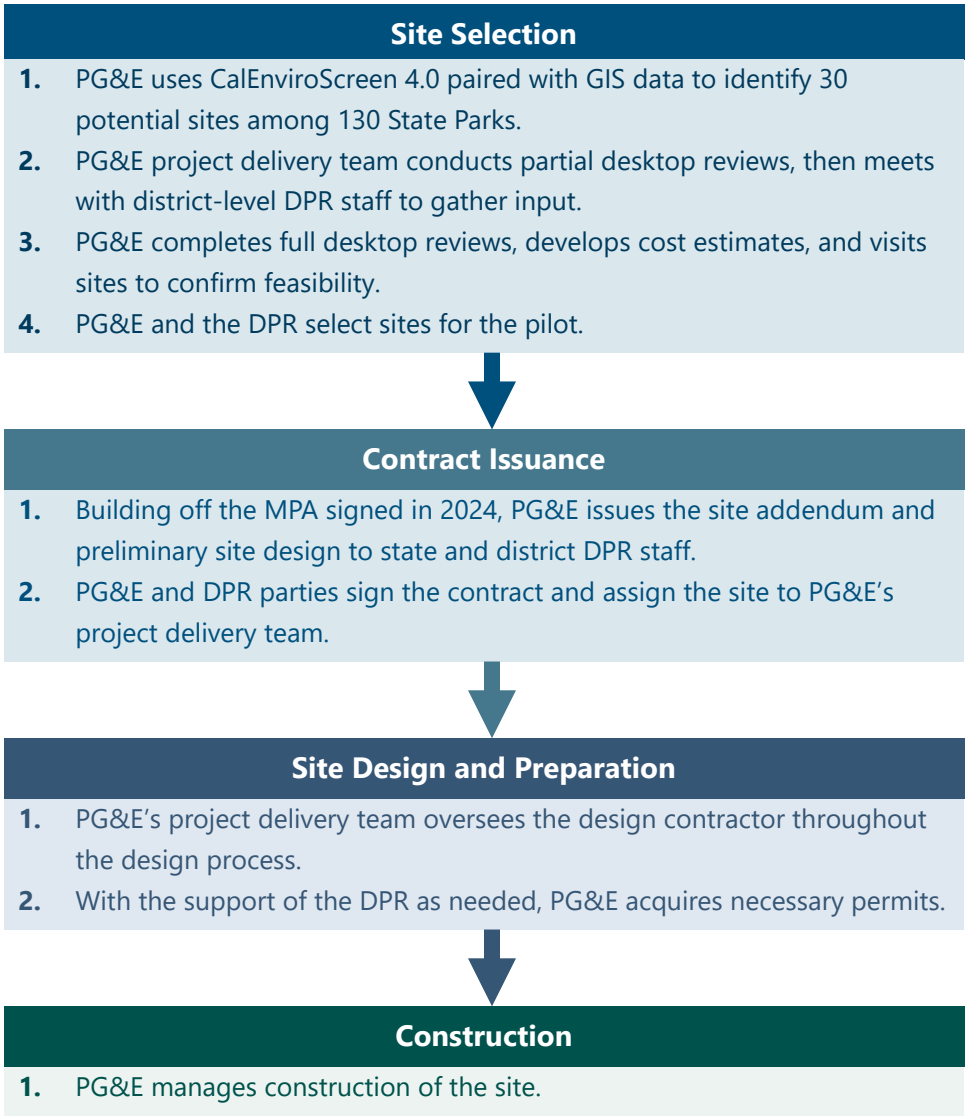




For the EV Charge Parks Pilot, PG&E staff used CalEnviroScreen 4.0 paired with publicly available GIS data to identify 30 potential sites, eight of which are in DACs. PG&E's project delivery team conducted partial desktop reviews of all 30 sites, then met with district-level DPR staff to gather information about visitor habits and needs for various parks. For 20 sites, PG&E completed full desktop reviews and developed high-level cost estimates, then visited 14 sites to confirm feasibility and develop detailed cost estimates. Together, PG&E and the DPR selected six sites based on preliminary site designs and cost estimates. In 2024, PG&E and DPR staff signed the MPA that established general terms of participation for the EV Charge Parks Pilot. Each individual site executed a site-specific addendum to the MPA based on the site's unique needs and designs. Figure 191 provides detail on the process of taking a site from selection to construction for the EV Charge Parks Pilot.[95]

[95] The EV Charge Parks Pilot Implementation Process figure draws on information from AL 7504-E, filed on February 21, 2025.

Figure 191. PG&E EV Charge Parks Pilot Implementation Process



Pilot Performance Metrics

The Evaluation Team reviewed sites participating in the EV Charge Schools Pilot and analyzed them by pilot status. Table 79 provides the count of PG&E EV Charge Schools Pilot sites by completion status for EY2025 and for the pilot to date. PG&E had no EV Charge Parks Pilot sites activated or constructed in EY2025.

Table 79. PG&E EV Charge Schools Pilot Complete Site Count by Status

Site Status	EY2025	Pilot to Date
Utility Construction Complete	3	15
Activated	3	15
Operational	3	15
Closed Out	3	15

In EY2025, PG&E activated three sites in the EV Charge Schools Pilot, all of which are located outside of DACs. These sites also finished construction and became operational and closed out in EY2025. The pilot concluded with 15 contracts, none of which were signed in EY2025.

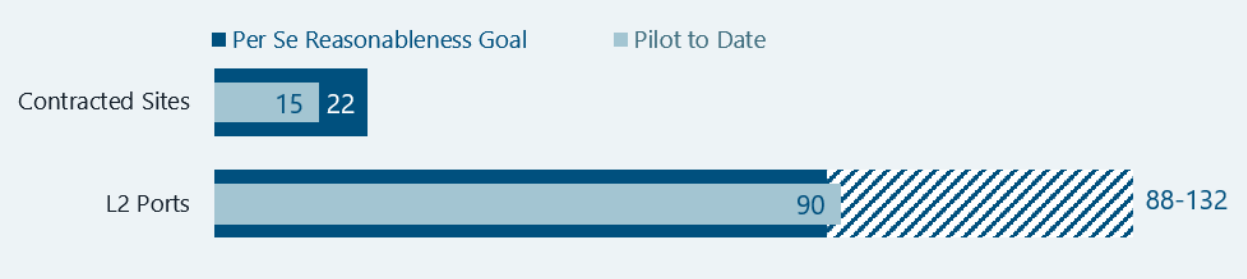
Table 80 presents site-level data for the EV Charge Schools Pilot, showing DAC status and the number of ports for the activated sites in EY2025 and in the pilot to date. In EY2025, no activated sites were located in a DAC, lowering the cumulative percentage of DAC sites to 40%, meeting the Pilot's per se reasonableness goal of 40%. The pilot deployed 18 L2 charging ports in EY2025, increasing the total installed to date to 90.

Table 80. PG&E EV Charge Schools Pilot Activated Site Data in EY2025 and Pilot to Date

EY2025			Pilot to Date		
Activated Sites inside DAC	Activated Sites outside DAC	L2 Charging Ports	Activated Sites inside DAC	Activated Sites outside DAC	L2 Charging Ports
0	3	18	6	9	90

As shown in Figure 192, the 15 activated sites to date in the PG&E EV Charge Schools Pilot meet 68% of the Pilot's per se reasonableness goal of 22 sites. These sites contain 90 L2 ports, meeting the pilot's minimum per se reasonableness goal of 88 L2 ports and 68% of its maximum port goal of 132 L2 ports.[96]

Figure 192. PG&E EV Charge Schools Pilot Site and Port Per Se Reasonableness Goal Progress



Hashed lines indicate that the per se reasonableness goal for L2 ports is in the range of 88 to 132.

The CPUC established six phases in the pilot timeline, per the SB 350 reporting template. Table 81 shows the median durations by pilot phase for EY2025 and PTD activated sites. For EY2025 sites in the EV Charge Schools Pilot, the median number of calendar days per phase ranged from 14 days for contract issuance to 466 days for design and permitting. Median phase durations in EY2025 were similar to those in the pilot to date, except for contract issuance and activation, both of which decreased in duration.

[96] Whereas SCE and SDG&E proposed overall port deployment goals for their Schools Pilots, the port goal for PG&E's EV Charge Schools Pilot is based on its decision to allow participating schools the option of installing either four or six L2 charging ports, which will result in between 88 and 132 ports installed in total.

Table 81. PG&E EV Charge Schools Pilot, Median Calendar Days per Phase

CPUC Pilot Phase	Median Calendar Days	
	EY2025 [a]	Pilot to Date [b]
Application Review	8	14
Site Assessment	22	18
Contract Issuance	7	32
Design and Permitting	466	466
Construction Complete	49	39
Activation	11	27

[a] "EY2025" represents the data for the sites activated in 2025.

[b] "Pilot to Date" represents the data from all activated sites from program inception for all program years.

Pilot Materials Summary

In previous evaluation years, PG&E staff maintained information about the pilots on the PG&E website,[97] which included details about the EV Charge Schools and Parks Pilots for prospective site hosts. The website also included frequently asked questions from prospective pilot participants. In 2025, because the EV Charge Schools and Parks Pilots were no longer accepting applications, PG&E stopped tracking page metrics.

Since 2021, PG&E has fielded a post-activation customer survey for the EV Charge Schools and Parks Pilots.[98] The survey assesses customer satisfaction with the online information available, the application process, the site walk, the contracting process, support from PG&E staff, and the pilot overall. Other than the customer survey, PG&E did not conduct marketing or outreach activities in 2025 for either pilot.

Budget Summary

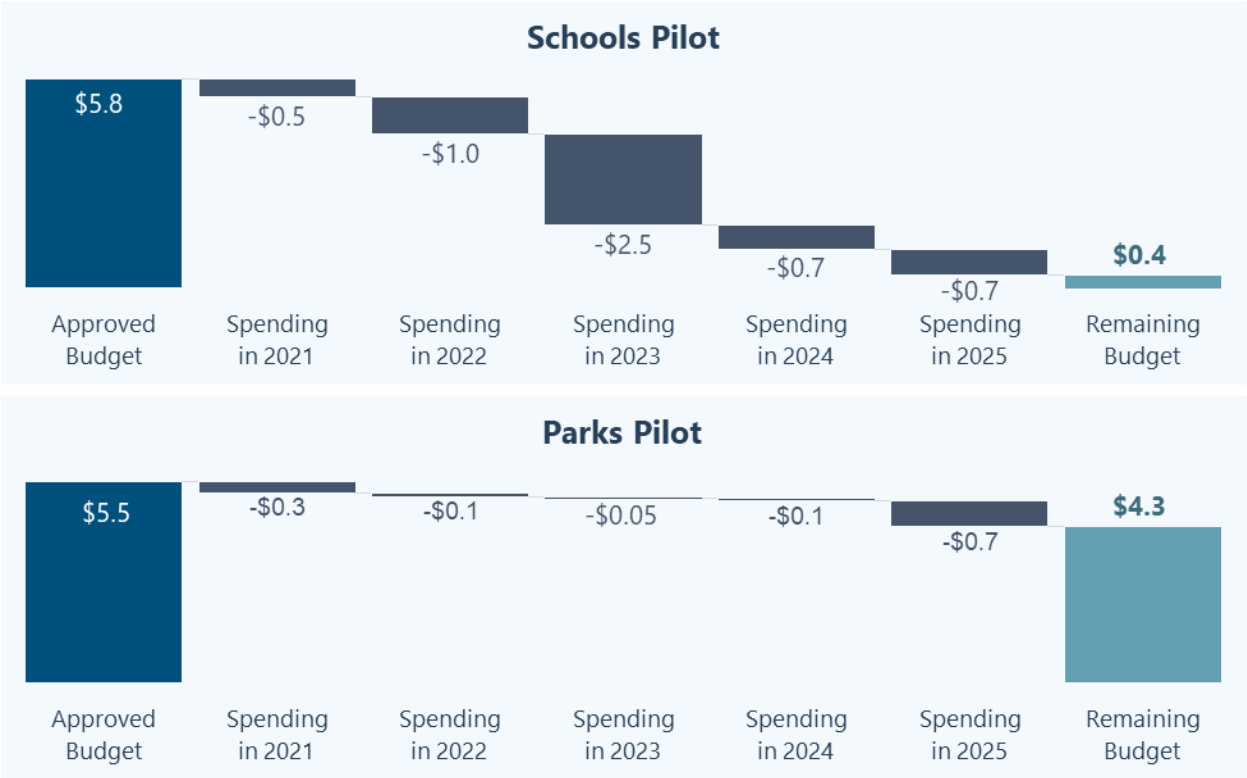
As shown in Figure 193, from pilot inception through 2025, PG&E spent $5.4 million of the $5.8 million approved for the EV Charge Schools Pilot and about $1.2 million of the $5.5 million approved for the EV Charge Parks Pilot. EV Charge Schools Pilot spending continued to outpace EV Charge Parks Pilot spending, as the final EV Charge Schools Pilot sites were completed and activated in 2025, while PG&E staff are still planning EV Charge Parks Pilot sites with DPR staff.

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97 Information about the pilots was included on PG&E's website in the "Electric Vehicle Programs and Resources" section, which was removed in 2025.

98 As of 2025, only EV Charge Schools Pilot sites had been issued the survey as EV Charge Parks Pilot sites had not been completed.

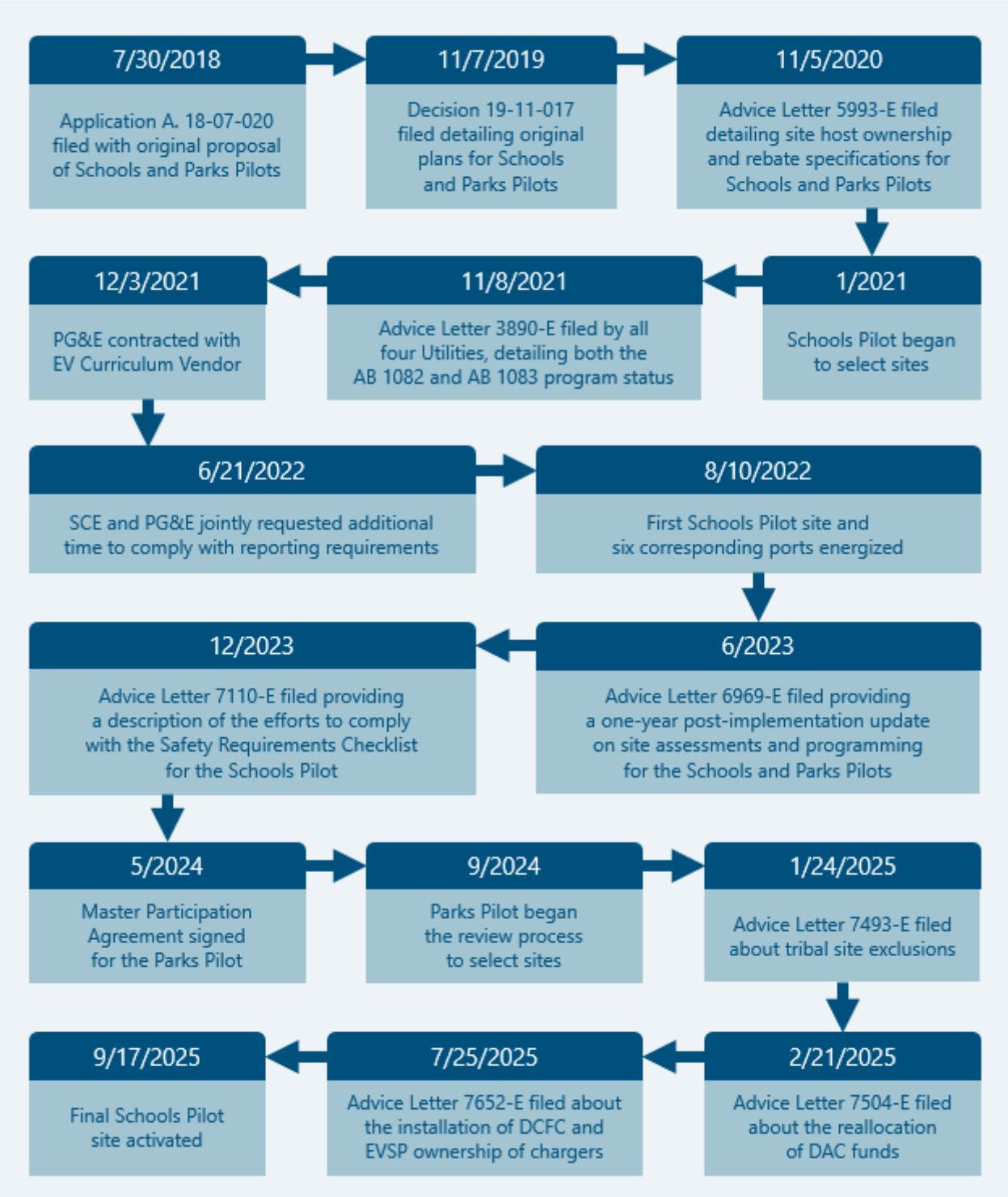
Figure 193. PG&E EV Charge Schools and Parks Pilots Budgets (Millions USD) as of December 31, 2025



Timeline

In 2025, PG&E staff focused on constructing and activating EV Charge Schools Pilot sites and did not file any formal Advice Letters or achieve any regulatory milestones for the EV Charge Schools Pilot. The only milestone for the EV Charge Schools Pilot in 2025 was the activation of the final site in September 2025. PG&E filed three Advice Letters for the EV Charge Parks Pilot in 2025: a Tier 1 letter about Tribal site exclusions on January 24, 2025, a Tier 2 letter about the reallocation of DAC funds on February 21, 2025, and a Tier 1 letter to confirm the installation of DCFC and EVSP ownership of the chargers, all of which the CPUC approved. Once the Tier 2 letter had been approved, PG&E staff were able to execute the remainder of the EV Charge Parks Pilot addenda by August 2025. Figure 194 presents key milestones for the EV Charge Schools and Parks Pilots.

Figure 194. PG&E EV Charge Schools and Parks Pilots Key Milestones



5.2.2. Findings

This section provides findings from analyses of the incremental EV adoptions, site visits, grid impacts, petroleum displacement, GHG and criteria pollutant reductions, and health impacts from EV Charge Schools Pilot sites as well as insights from Utility staff interviews about both pilots.[99]

Table 82 summarizes key impact parameters for the EV Charge Schools Pilot in EY2025 and for the pilot to date. Annual estimates of impacts are provided for metrics calculated as part of the impact evaluation. The table also provides estimates of impacts across all sites included in the pilot population through the end of 2025.

Table 82. PG&E EV Charge Schools Pilot Impacts Summary

Impact Parameter	EY2025 Sites [a]	EY2025 Sites Percentage in DAC	Pilot-to-Date Sites Actual	Pilot-to-Date Sites Actual Percentage in DAC
Population of Activated Sites	3	0%	15	40%
Sites included in analysis	3	0%	15	40%
Charging Ports Installed	18	0%	90	40%
Electric Energy Consumption (MWh)		0%		49%
Petroleum Displacement (GGE)	1,345	0%	35,102	49%
GHG Emission Reduction (MT) [b]	12.2	0%	283.9	50%
PM_{10} Reduction (kg)	0.07	0%	1.49	49%
$PM_{2.5}$ Reduction (kg)	0.06	0%	1.37	49%
ROG Reduction (kg)	0.67	0%	22.87	50%
CO Reduction (kg)	28.70	0%	808.56	50%

[a] Energy consumption, petroleum displacement, and emissions reductions are based on annualized data. Pilot-to-date results are based on actual data (see *Appendix B* for details).

[b] GHGs include CO_2, CH_4, and N_2O multiplied by their respective GWP as defined by IPCC AR5 (see *Appendix B* for details).

Incremental EV Adoption

There are two main channels through which the availability of public charging networks may affect EV purchases. The first is a network effect, through which EV owners gain increased access to the public charging stations because of the stations' placement at destinations such as workplaces, commercial establishments, schools, and parks. The Evaluation Team expects the availability of EV charging equipment at convenient locations (for midday charging away from home) to increase the convenience of owning an EV (such as by lessening range anxiety) and to increase the probability of EV ownership. The second channel is a neighborhood effect on the driving population living in areas neighboring the public EV charging stations. The Evaluation Team expects the availability of nearby charging infrastructure to reduce the cost of EV ownership by providing alternatives to home charging. We expect that public EV charging will have the biggest impact on residents of multifamily buildings, many of whom will have limited access

[99] Only insights from Utility staff cover both the EV Charge Schools and Parks Pilots, as only the EV Charge Schools Pilot has sites in 2025.

to EV charging equipment, and on low-income households, which may be unable to afford home EV charging equipment. Public charging access may boost EV ownership through both channels, and there may be positive interactive effects between the channels that boost the overall impact of public charging networks. The Evaluation Team focused on analyzing the second channel and will analyze impacts for the first channel separately when data become available.

The Evaluation Team estimated the effect of the EV Charge Schools Pilot public charging stations on household EV adoption for neighboring populations with a two-stage analysis. In Stage 1, we looked at historical impacts of public EV charging on vehicle ownership. See *Appendix B* for the details of the Stage 1 analysis.

Using the impact estimates from the Stage 1 analysis the Evaluation Team estimated the impact of PG&E investments in public charging on EV ownership for Stage 2.[100] By the end of EY2025, 15 charging sites in PG&E's Schools Pilot had been activated. We estimated the impact of these stations based on annual EV registrations as well as cumulative EV registrations driven by the Schools Pilot through the end of 2025.

Based on the composite measure of public charging access, the Evaluation Team calculated the change in access to public charging due to PG&E's Schools Pilot investment for each CBG where the investments affected access. Table 83 shows that the average change in access across all affected CBGs from pilot sites through 2025 was over five, and the average change in the number of chargers (ports) was over four per affected CBG. The average normalized EV annual registration per 1,000 households was almost 44 in the affected CBGs in the 2020 baseline year.

Table 83. PG&E EV Charge Schools Pilot Summary Statistics of Effects on 47 Affected CBGs

	Change in Composite Measure of Access [a]	Change in Number of Chargers	Normalized Annual EV Registrations [b]	Number of Households [c]
CBG Mean	5.37	4.47	43.85	390.40
Standard Deviation	(3.48)	(2.64)	(45.48)	(193.03)

These values are averages for the CBGs whose access to public charging was affected by PG&E's investments.

[a] Change in composite measure of access and number of chargers is from 2020 to 2025.

[b] Normalized annual EV registrations are average annual values in the affected CBGs in 2020 per 1,000 households.

[c] Number of households is based on 2015–2019 ACS.

The Evaluation Team calculated the impact of the EV Charge Schools Pilot Utility charging investments on neighboring EV ownership. This involved combining the OLS and IV-2SLS regression estimates of the impact of public charging access on EV registrations from Stage 1 with the estimates of the CBG changes

[100] The Stage 1 analysis used vehicle registration data from 2015 to 2023, the most recent period with complete information at the CBG level. The EY2025 estimates assume that the impact of Utility-specific stations remains unchanged over time, which may not reflect actual market conditions and technological changes in 2025.

in public charging access and household counts.[101] The impacts of the PG&E investments on EV registrations will depend on the extent to which the investments increased access to EV charging in the affected CBGs and the number of neighboring households in the CBGs.

Table 84 shows estimates of the annual and cumulative EV registrations attributable to the PG&E EV Charge Schools Pilot charging investments. Based on the OLS long differences model,[102] PG&E EV Charge Schools Pilot investments in charging facilities increased EY2025 annual EV registrations by eight vehicles and cumulative EV registrations by 18 vehicles. Based on the IV-2SLS long differences model, the Schools Pilot investments increased annual EV registrations by 17 vehicles and cumulative EV registrations by 41 vehicles. The Evaluation Team prefers the IV-2SLS-based estimates because they account for the potential endogenous siting decisions of public charging (i.e., siting public charging infrastructure in locations likely to have above- or below-average rates of EV adoption). These estimates reflect the 15 activated EV Charge Schools Pilot facilities operating for a full year.

Table 84. PG&E EV Charge Schools Pilot Effects of Utility Investments on 2025 and Pilot-to-Date EV Registrations

	EY2025		Pilot to Date	
Analysis Model	OLS	IV-2SLS	OLS	IV-2SLS
Increase in EV Registrations	8.48	16.50	18.11	40.65
Standard Error	(0.45)	(1.47)	(0.68)	(2.41)

The Team estimated the OLS long differences using data for all CBGs in the analysis sample and estimated the IV-2SLS long differences for CBGs in the 20 largest California cities. The long differences are annualized eight-year estimates. For each affected CBG, the Team calculated the increase in annual registrations as the product of the regression-based access coefficient divided by eight, multiplied by the change in composite public charging access from utility investments (between baseline 2020 and EY2025), multiplied by the number of CBG households (in thousands). Robust standard errors clustered at the CBG level are in parentheses.

The PG&E EV Charge Schools Pilot investments in public charging had relatively small impacts on EV ownership in EY2025. Across all 47 affected CBGs, the total annual number of EV registrations is about 2,061 (47 * 43.85), so the preferred IV-2SLS regression estimates the cumulative impact of the PG&E Schools Pilot to be an increase in EV registrations of about 2.0% (40.65/2,061). Although modest, this impact has increased from EY2024 (1.4%). An average of 44 EV registrations per CBG in 2020 puts these CBGs in the 64th percentile of the EV registration distribution of CBGs, implying a relatively high level of baseline EV registration.

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[101] In Stage 1, the Evaluation Team estimated the impact of public EV charging access on EV ownership. Stage 2 built on the Stage 1 analysis and was an attribution analysis for Utility-specific investments. A notable benefit of this approach is that it can be applied to evaluations of other programs increasing EV charging access as well, which allows methodological consistency.

[102] The long differences model estimates indicate the impact of public charging on EV registration over eight years. The Team annualized these estimates by dividing the results by eight.

Highlights

- The model's output shows that the PG&E Schools Pilot may have contributed to the adoption of 41 EVs by households neighboring the infrastructure.
- The PG&E EV Charge Schools Pilot increased EV registrations by an estimated 2.0% across affected CBGs, up from 1.4% in EY2024, indicating modest but growing impacts despite relatively high baseline EV adoption.

Site Visit Findings

The Evaluation Team visited the three EV Charge Schools Pilot sites activated in 2025, which added 18 L2 ports with 113 kW of EV charging capacity. This brings the total sites in the pilot to date to 15 with 90 L2 ports and installed capacity of 603 kW. Figure 195 and Table 85 show the total number of ports and observed capacity for sites activated in EY2025 and in the pilot to date.

Figure 195. PG&E EV Charge Schools Pilot L2 Ports and Capacity Observed in 2025 and Pilot to Date

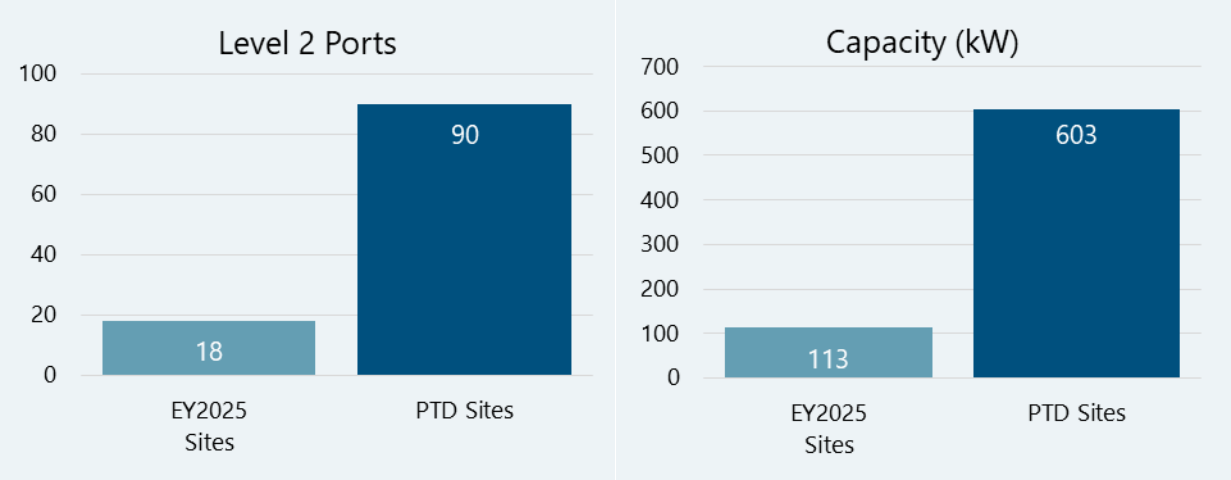


Table 85. PG&E EV Charge Schools Pilot Summary of Ports and Capacity Observed during Site Visits

Site Visit	Number of Sites	Number of Ports	Installed Capacity
EY2025	3	18	113
Pilot to Date	15	90	603

All three EY2025 sites were similar to those visited in past evaluation years. Each of the 15 schools the Team visited in the pilot to date has six charging ports and similar charger types, installed charging capacity, and site layout and design. The Evaluation Team assessed the total number of parking spaces within reach of a charging cord, regardless of whether these spaces were designated as EV charging spaces. Typically, head-to-head parking offers high access to charging ports if EVSE are not adjacent; however, none of the three schools the Team visited in 2025 had head-to-head parking.

Figure 196 shows the site layout for two of the three sites activated in 2025. As shown in the figure, six charging ports serve six electrified parking spaces with two ADA-accessible (one site accomplishes this

with three and another with four EVSE based on the layout). All three sites also had a one-to-one ratio of parking spaces within reach of charging ports.

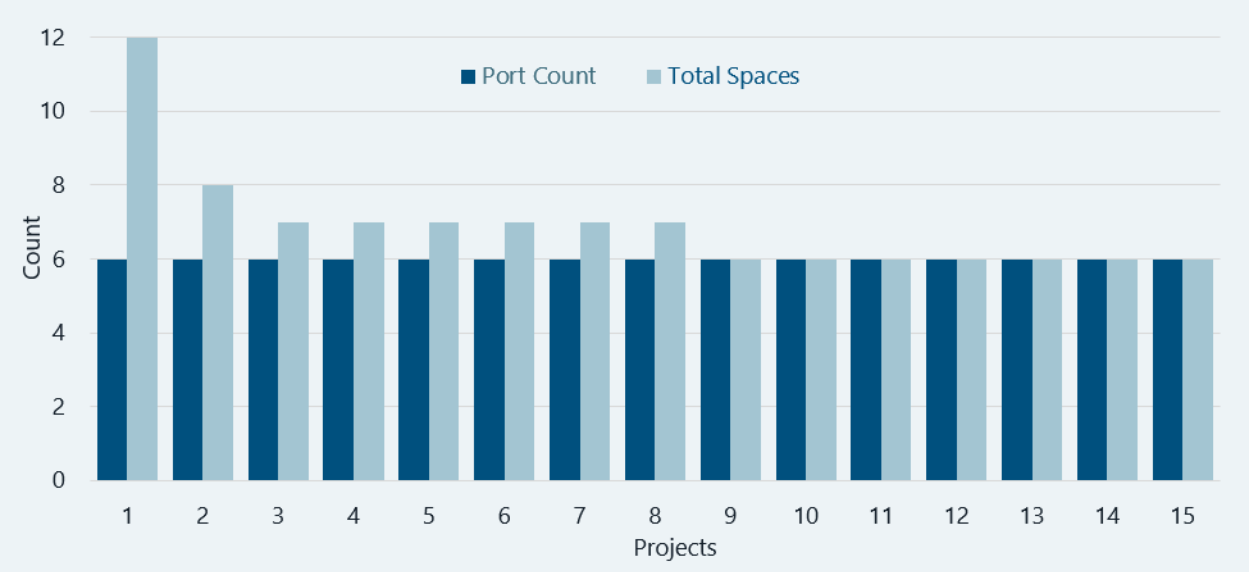
Figure 196. PG&E EV Charge Schools Pilot EY2025 Site Layouts



Left panel: Three dual-port EVSE with two of six electrified parking spaces ADA accessible.
Middle panel: Dual-port L2 EVSE.
Right panel: Two single-port EVSE serving two ADA-accessible parking spaces
and two dual-port EVSE serving four electrified parking spaces.

Figure 197 shows the number of ports and the number of parking spaces that can access these ports for each of the EV Charge Schools Pilot sites the Evaluation Team has visited in the pilot to date. As illustrated by the figure, most sites offer a one-to-one or slightly higher ratio of parking spaces to charging ports, with one exception where each charging port can reach two parking spaces. Having multiple parking spots in reach of a single charging port where feasible allows other vehicles to use a charging port without moving the first vehicle, which can improve charger utilization.

Figure 197. PG&E EV Charge Schools Pilot Visited Sites Charging Port Availability by Site for PTD Sites



The Evaluation Team reviewed pricing structures available to EV drivers, including costs for idle time to encourage charger turnover and variable pricing to encourage charging when energy emissions and costs

are low and discourage charging when costs are high (such as from 4 p.m. to 9 p.m.). Two of the three EY2025 sites had TOU pricing ($0.48/kWh between 4 p.m. and 9 p.m. and $0.28/kWh or $0.25/kWh during other times of day), and one site offered a set price of $0.42/kWh for all times. The pricing at all three sites were set by the schools.

Across all 15 EV Charge Schools Pilot sites, six sites provide TOU pricing to EV drivers while nine sites provide flat rates. One EV Charge Schools Pilot site charged $0.60/kWh with an additional $0.50/hour idle fee that starts 90 minutes after charging has been completed. Six sites showed use of TOU pricing, and at least one site appeared to be providing free charging. One school had specific signage restricting public charging during regular school hours but allowing it before and after school was in session.

Highlights

- The Evaluation Team visited the three sites activated in 2025, all of which had a typical layout for the PG&E EV Charge Schools Pilot with six electrified parking spaces and a one-to-one ratio of parking spots to ports.
- The EV Charge Schools Pilot has installed 90 L2 ports in the pilot to date providing more than 600 kW of installed charging capacity.
- Two sites activated in 2025 displayed TOU pricing ranging from $0.25/kWh to $0.48/kWh, while the other site displayed $0.42/kWh all day. Pricing varies significantly for PTD sites, with the highest-cost site charging $0.60/kWh and a site that appeared to provide free charging.
- Pricing is set by the school for each site.

Site Costs

The Evaluation Team conducted an analysis of the 15 school sites activated from EY2021 through EY2025 with fully closed out finances as of December 31, 2025. The set of fully closed out sites is smaller than the set of activated sites because of the time involved in performing activities such as collecting receipts, paying invoices, and obtaining administrative approvals. Cost estimates presented here are in nominal dollars. The 15 sites all had L2 ports, with an average of 40.6 kW of installed capacity and six ports per site.

Figure 198 shows the distribution of site-level costs for the 15 sites. The horizontal lines of the boxes show the 25th, 50th, and 75th percentile of sites; the X denotes the mean site cost; and the three panels are defined as follows:

- **Utility Infrastructure Costs.** Site costs borne by the Utility for TTM and BTM.[103]
- **Ratepayer-Funded Costs.** All site costs paid for by the Utility, including TTM, BTM and EVSE rebate.

[103] Utility infrastructure costs are the same as the ratepayer-funded costs, except the Utility infrastructure costs do not include EVSE rebates.

- **Estimated All-In Costs.** The total estimated cost of installing the site, including capital and labor costs for the Utility and the customer. The value is calculated by summing TTM,[104] BTM, and EVSE costs.

Figure 198. PG&E EV Charge Schools Pilot Per-Site Costs Organized by Three Perspectives, Across 15 Closed-out PTD Sites

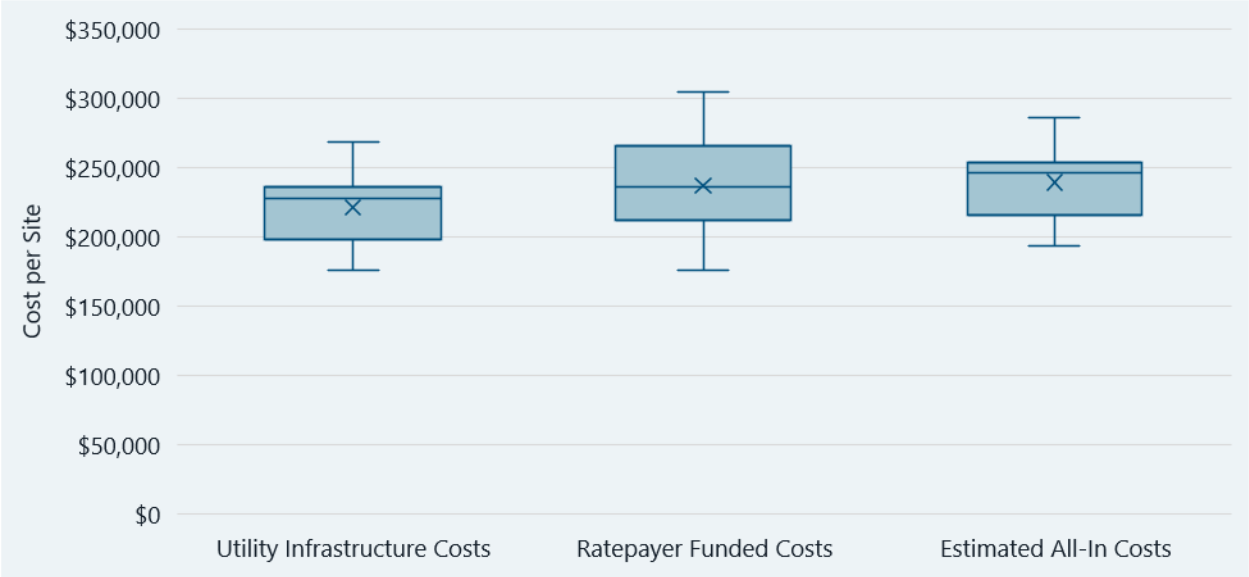


Figure 199 shows average estimated all-in costs for the 15 sites. BTM is the largest cost across the sites, followed by TTM, then EVSE. Together, the average all-in TTM, BTM, and EVSE cost is $239,408.

[104] The Utility pays 100% of the TTM costs and therefore reports actual TTM costs to the Evaluation Team.

Figure 199. PG&E EV Charge Schools Pilot Average All-In Costs, Across 15 Closed-out PTD Sites

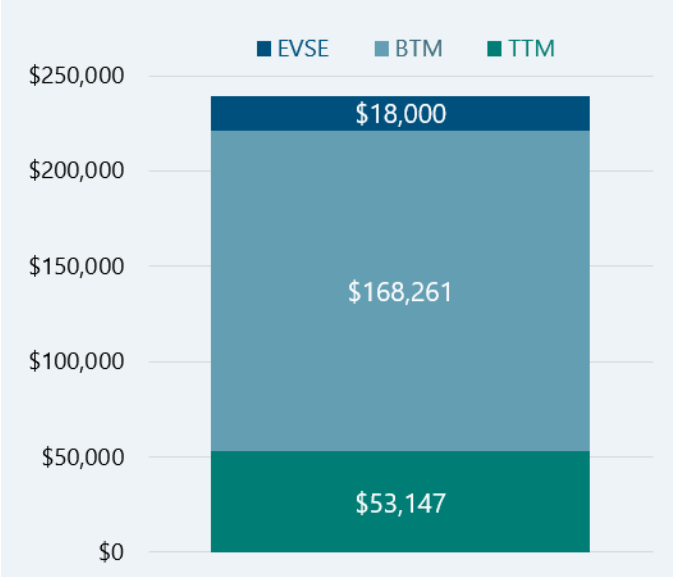


Figure 200 shows the distribution of Utility infrastructure costs (corresponding to the far-left panel in Figure 198) per site and per kilowatt. The average Utility infrastructure cost of TTM and BTM borne by PG&E across PTD sites was $221,408 per site[105] and $5,465 per kilowatt.[106]

Figure 200. PG&E EV Charge Schools Pilot Utility Infrastructure Cost per Site and per Kilowatt Across 15 Closed-out PTD Sites



[105] Calculated by summing all TTM and PG&E-sponsored BTM costs and dividing by the number of sites. Number reflects maximum infrastructure rebate offered for sites that have not yet applied for rebates, which may vary significantly from actual infrastructure rebate amount paid.

[106] Calculated by summing all TTM and PG&E-sponsored BTM costs and dividing by the sum of installed capacity.

Highlights

- Estimated all-in costs paid by the customer and PG&E vary widely between sites, with an average of $239,408 per site. On average, BTM was the largest cost across the sites, followed by TTM and EVSE costs.
- The average utility infrastructure cost in the pilot to date, including TTM and BTM borne by PG&E, was $221,408 per site, and $5,465 per kilowatt.

Grid Impacts

The Evaluation Team determined grid impacts for the PG&E EV Charge Schools Pilot based on the analysis of energy consumed by operational charging stations installed through the PG&E EV Charge Schools Pilot through 2025, combined with charging session data from the NSPs.

Data Sources

The primary data source for the analyses detailed in this section is the energy usage–related data provided in regular 15-minute intervals from the AMI. Other data sources include charging session-specific data provided by NSPs. There are several important differences between AMI and NSP data. While AMI data reflect only energy usage, NSP data include session start and stop time, the duration of a vehicle's connection to a charging port, the duration of a vehicle actively pulling power, and the specific port used for a session. An AMI meter does, however, track standing loads (such as those the EVSE uses for communications, cooling, active power converters, solenoids, and screens), which NSPs typically cannot do. When AMI data is missing from the dataset, the Evaluation Team uses NSP data to fill the gaps.

Summary of Grid Impacts

Table 86 presents the estimated PG&E EV Charge Schools Pilot grid impacts summary.

Table 86. PG&E EV Charge Schools Pilot Grid Impacts

Impact Parameter	Actual 2025 [a]	Actual PTD	10-Year Projection PTD
Operational Sites	3	15	15
Installed Capacity (kW)	144	633	633
Electric Energy Consumption, MWh			1,814
On-Peak (4 p.m. to 9 p.m.) MWh (and % of total)			N/A
Maximum Demand, kW (with date and time)	161 (12/10/25 10:15 a.m.)	169 (9/13/24 5:15 p.m.)	N/A
Maximum On-Peak Demand, kW (with date and time)	76 (9/26/25 4 p.m.)	169 (9/13/24 5:15 p.m.)	N/A

[a] Energy consumption, peak consumption, and demand data are based on PTD activated sites for calendar year 2025.

The remainder of this section offers detailed findings on actual consumption, demand, and charging session–oriented trends of the combined sites for 2025.

Energy Trends

Three pilot sites were activated in 2025, bringing the total activated sites through the end of 2025 to 15. Pilot-to-date sites in the PG&E EV Charge Schools Pilot consumed over 220 MWh in 2025 (50% higher than in 2024), leading to a total of nearly 500 MWh for all sites in the program to date.

Figure 201 plots monthly energy consumption and maximum demand values. The figure shows a general upward trend, with significant drops in demand during the summer months, coinciding with the school year. The highest energy use month in 2025 was October with more than 20 MWh, and the highest demand across all sites in 2025 was 161 kW on December 10th at 10:15 a.m.

Figure 201. PG&E EV Charge Schools Pilot Monthly Energy Consumption and Maximum Demand

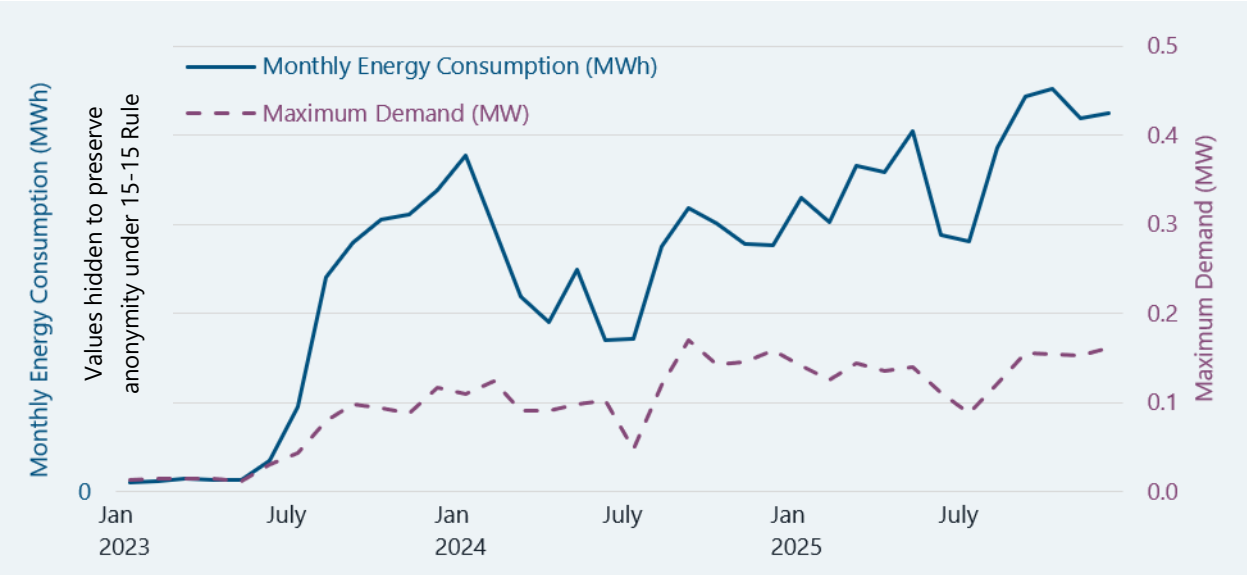


Figure 202 below highlights daily energy trends of demand and consumption. Daily energy consumption ranged between 1 MWh and 1.5 MWh, with the highest energy consumption occurring toward the end of 2025. Monthly maximum demand has remained consistent since mid-2024, at around 160 kW. The sections below present more detail about individual site attributes.

Figure 202. PG&E EV Charge Schools Pilot Daily Energy Consumption and Maximum Demand, Pilot-to-Date Sites

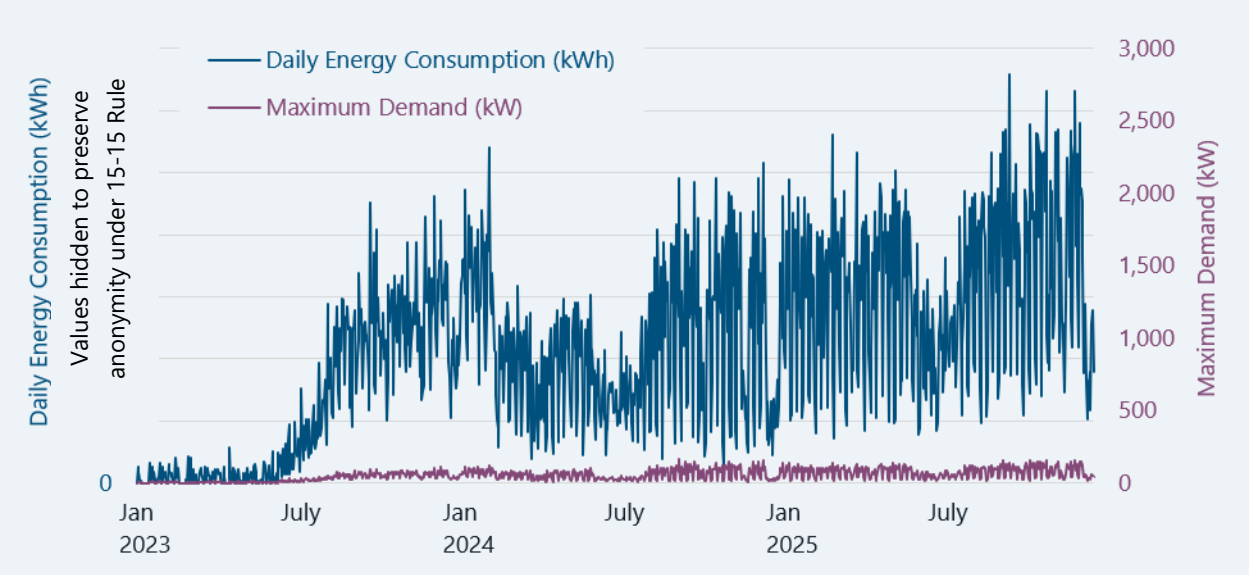
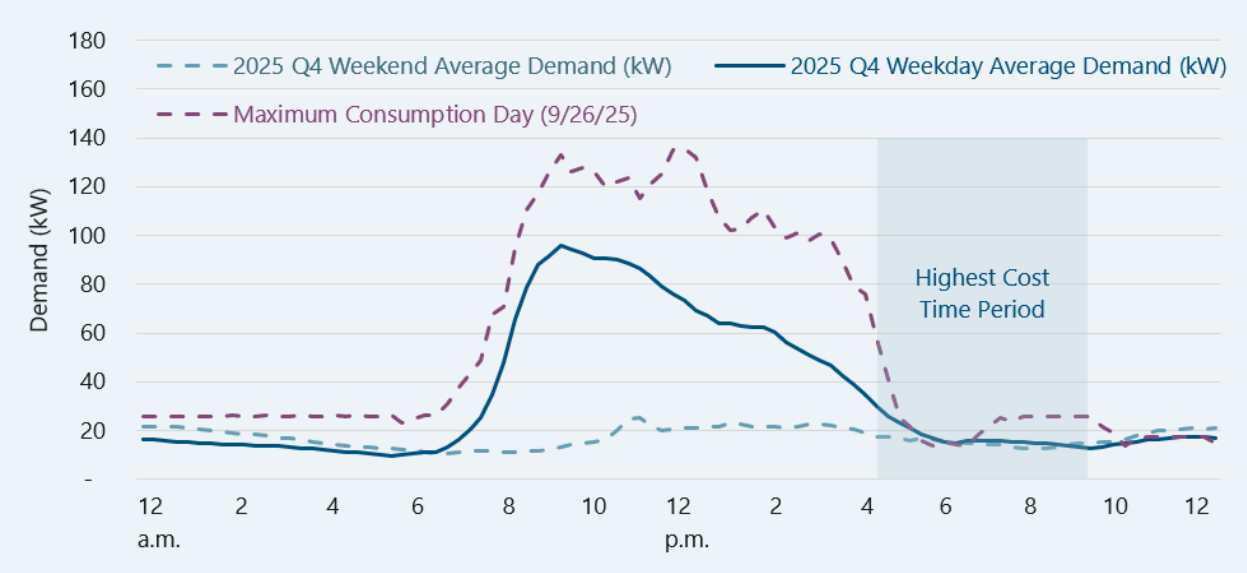


Figure 203 shows the average load curve on weekdays and weekends in the fourth quarter of 2025 for the EV Charge Schools Pilot and presents an example of a high utilization day for comparison. The average weekday load shape of sites in the EV Charge Schools Pilot is consistent with typical workplace charging. This pattern consists of a load that ramps up between 6 a.m. and 9 a.m. as drivers arrive, peaks between 9 a.m. and 10 a.m. as all connected vehicles are charging, and tapers over the rest of the day as individual vehicles complete their charge. On average, weekend consumption varies less than on weekdays, but sites show slightly more use overnight on weekends than on weekdays, which may indicate use of the chargers by the local community.

Several sites also show regular overnight utilization on both weekdays and weekends, which could be from staff or nearby residents. Overnight and weekend utilization demonstrates the benefits of this pilot to the local community and leads to increased load factor.

Figure 203. PG&E EV Charge Schools Pilot Average Weekday and Weekend Q4 2025 Load Curves



The impact of pricing on how and to what extent EV drivers use energy remains inconclusive for sites in the EV Charge Schools Pilot with only about half using TOU pricing. Surveying schools or drivers leads to findings about driver experiences and awareness of pricing, and during site visits the Evaluation Team can typically determine what pricing EV drivers receive. Workplaces tend to see a correlation between charging activity and the lowest TOU rates (late morning into early afternoon), which also typically aligns with a higher proportion of renewable energy on the grid, even if pricing available to EV drivers does not take this into account.

Usage Trends

The EV Charge Schools Pilot initiative and other public-facing projects across the state may provide insight into how long similar sites will take to reach operational maturity. Factors that affect sites' timelines may include how EV drivers gain access to chargers and whether the availability of workplace charging influences drivers to trade their conventional vehicle for an EV or to keep an EV they already have.

By the end of 2025, 15 sites were operational and most of those sites had two or more years of operations for the Evaluation Team to draw upon to analyze site performance over time. This section assesses pilot characteristics by comparing energy consumption, load factor (a measure of consistency of usage), and total charging sessions across sites. This analysis begins when a site begins to show charging sessions, rather than when AMI data are first available, to eliminate early periods when chargers are powered up but not commissioned by their NSPs (i.e., in a testing period) or available for public use. Month zero is defined as the month when public access began.

Figure 204 and Figure 205 aggregate monthly energy consumption trends for active sites, grouping sites by whether they have achieved a 15% load factor in any single month to improve data visualization.

All sites have the same number of charging ports and capacity, allowing for a direct comparison on a site-by-site basis. With some sites having reached nearly three years of operations, the sites can be classified by level of utilization based on whether they have achieved 2 MWh in a month.

Figure 204. PG&E EV Charge Schools Pilot Monthly Energy Consumption Based on Site's Operational Time, Load Factor <15%

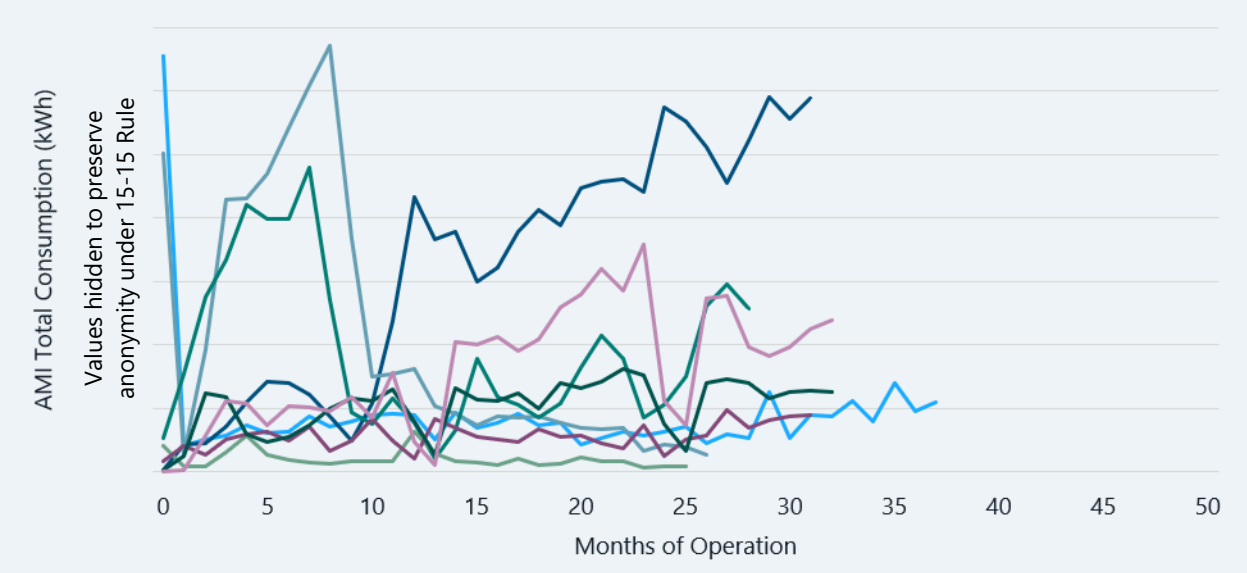


Figure 205. PG&E EV Charge Schools Pilot Monthly Energy Consumption Based on Site's Operational Time, Load Factor >15%



Figure 206 and Figure 207 show the monthly load factor of EV Charge Schools Pilot sites. Load factor compares actual monthly energy consumption to what consumption would be if the maximum demand were maintained for the entire month. A constant demand, for example, would result in a 100% load

factor (which is highly unlikely in practice). This does not indicate how much capacity is being utilized (demand vs. installed capacity) but it does show whether site usage is increasing. Analyzing growth rates, whether by consumption, load factor, or sessions, may help site and Utility staff better understand the level of demand at a workplace charging site and predict how long it will take a site to reach full operation and utility.

Figure 206 shows all sites in the EV Charge Schools Pilot that have achieved a load factor of at least 12% during any operational month. As shown, only two sites have achieved a consistent load factor >12% over the past year, and one other had high utilization in the first year after activation but has since dropped. The majority of these sites have an average load factor of between 5% and 10%.

Figure 206. PG&E EV Charge Schools Pilot Monthly Load Factor Based on Site's Operational Time, Load Factor >12%

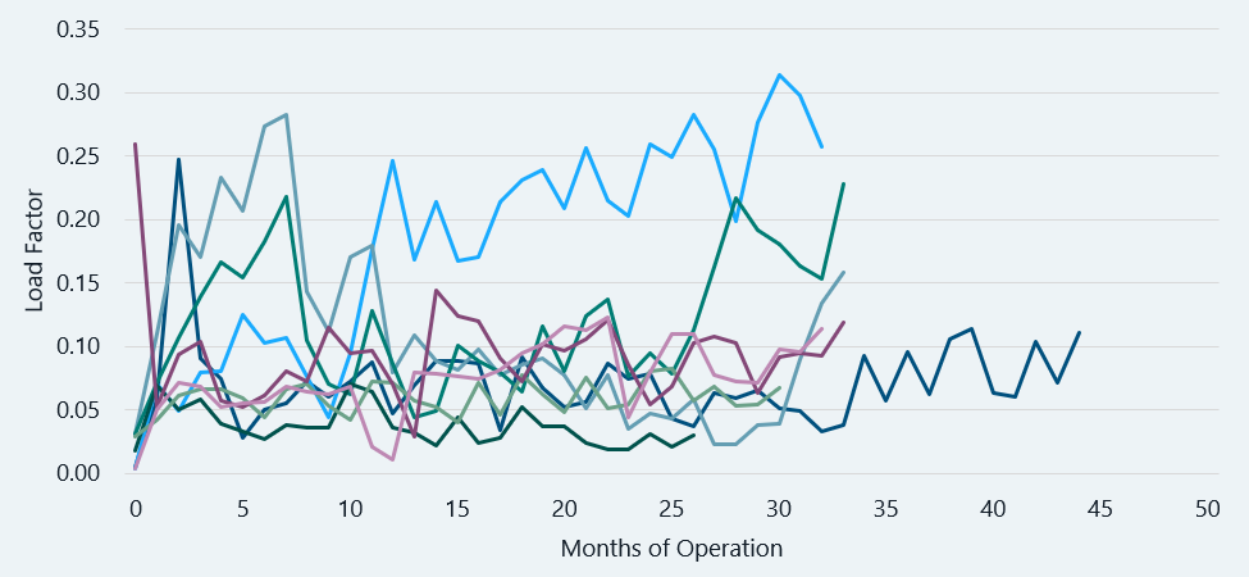
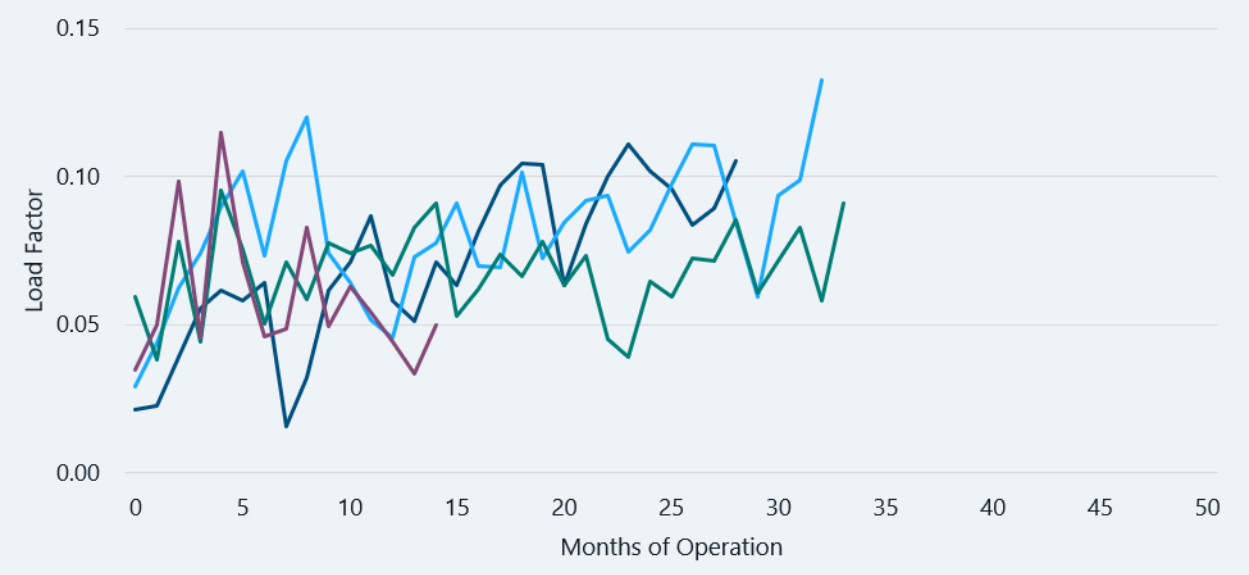


Figure 207 show sites in the EV Charge Schools Pilot that have never achieved a monthly load factor of 12%. Similar to those presented in Figure 206, these sites typically have a monthly load factor of 5% to 10%, with a few sites a bit higher. Some months with particularly low levels of charging occur in the summer or over school breaks. Overall, the variation in load factor suggests that maximum demand is very inconsistent at most sites, reflecting low utilization and slow uptake by EV drivers at these sites.

Figure 207. PG&E EV Charge Schools Pilot Monthly Load Factor Based on Site's Operational Time, Load Factor <12%



High Utilization Sites: Weekend and Overnight Examples

Several of the EV Charge Schools Pilot sites show much higher overnight or weekend utilization than is typical for a workplace charging site. These sites have three distinct charging periods: business hours from Monday through Friday, overnight, and weekend, which indicate that they are public EV charging resources, rather than private sites.

Figure 208 compares sites with typical Monday through Friday operations with higher utilization sites that have overnight or weekend charging in the fourth quarter of 2025. The Baseline Weekday series in Figure 208 includes all active pilot sites and shows a distinct, short-duration increase in load on weekday mornings that tapers steadily during business hours. Baseline sites have minimal overnight load on both weekdays and weekends.

Sites that allow public access generally show more consumption than in a workplace-oriented site, providing benefits to the local community. Examples show three to five times more utilization during the day on weekends than for the baseline and high utilization overnight.

Figure 208. PG&E EV Charge Schools Pilot Demand per Port Comparing Baseline and High Utilization Sites

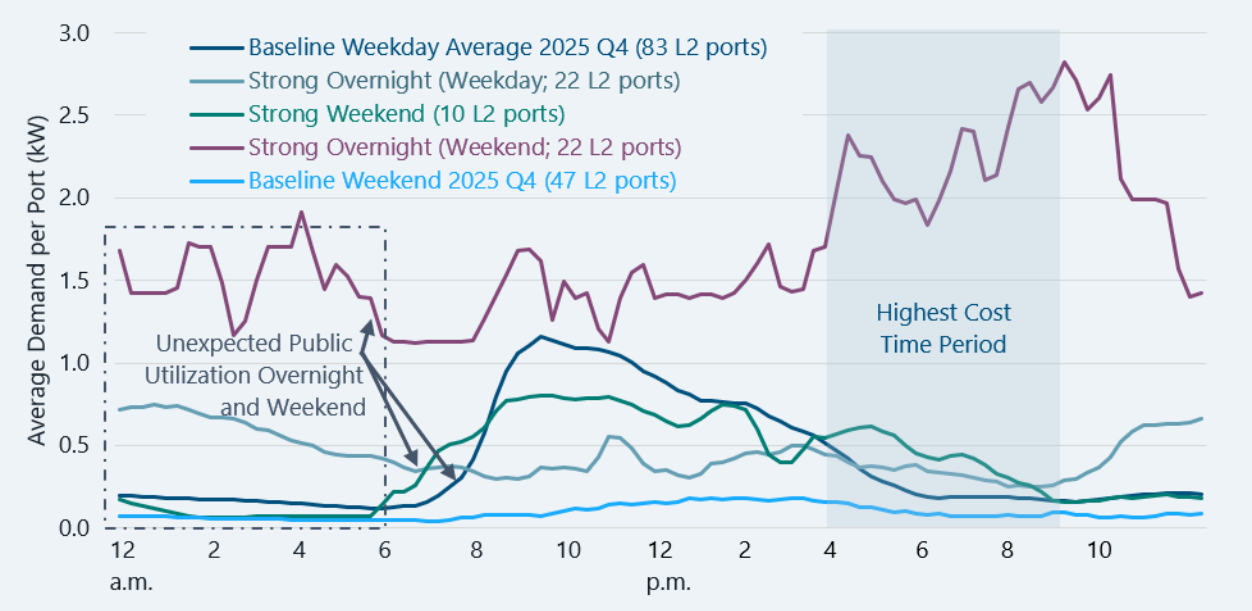


Figure 209 shows daily charging sessions that the EV Charge Schools Pilot has achieved resulting in nearly 19,600 charging sessions to date, approximately 40% of which were in EY2025. Because these sites are installed at schools, utilization dips noticeably during summer break. The number of daily charging sessions have been fairly consistent at between 30 and 40 since the second half of 2023 despite activation of four new sites in 2024 and 2025.

Figure 209. PG&E EV Charge Schools Pilot Daily Charging Sessions PTD Sites

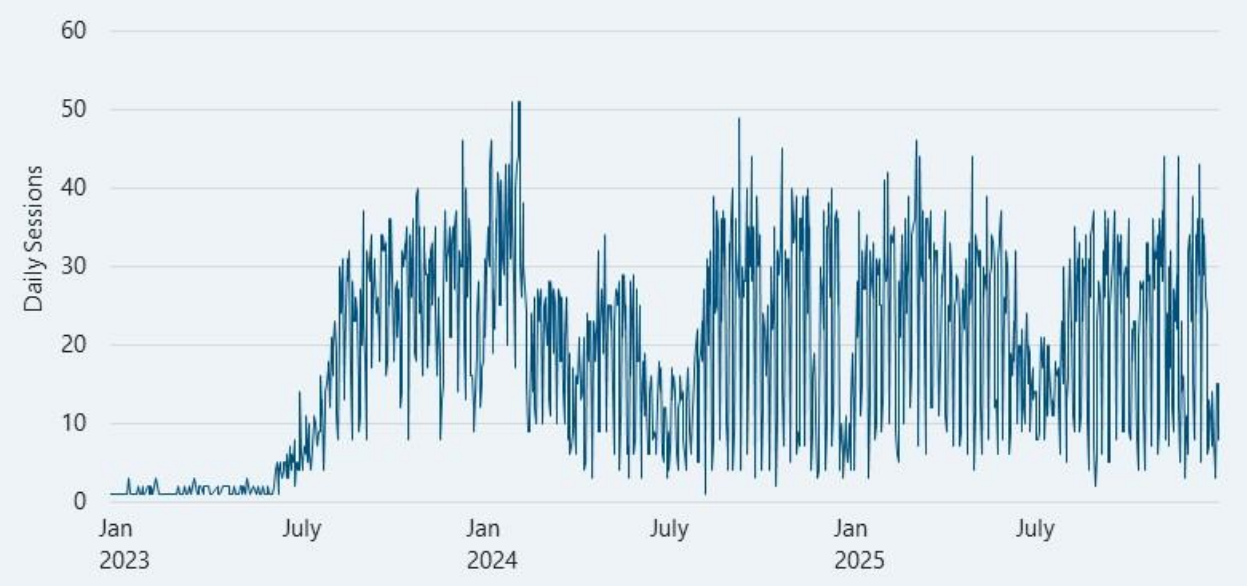


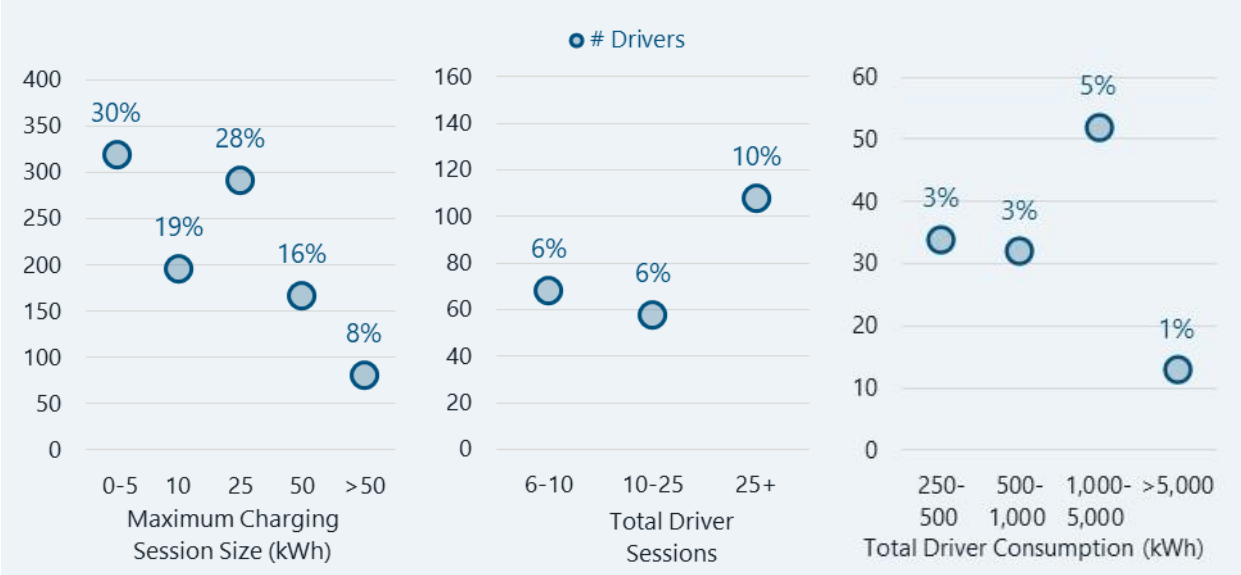
Figure 210 presents the distribution of charging sessions by kilowatt hours consumed for sites in the EV Charge Schools Pilot to date. The Evaluation Team did not include erratic charging sessions (below 1 kWh or less than 0.1 hours). Charging sessions of up to 12 kWh dropped in EY2025 to approximately one-third of all sessions. Charging sessions between 12 kWh and 25 kWh of consumption stayed very similar, and larger sessions (greater than 25 kWh) grew.

Figure 210. PG&E EV Charge Schools Pilot Charging Session Count by Consumption Size for PTD Sites



Figure 210 provides a perspective of how much drivers consume when they charge. Figure 211 highlights statistics of exceptional utilization ranging from 10% to 20% of drivers on the panels in the middle and on the right of the figure. NSP data from EV Charge Schools Pilot sites show that the pilot appears to have supported approximately 1,050 drivers in the pilot to date. Of these drivers, over 22% (234) have engaged in at least six charging sessions over the lifetime of the program, and 10% (108) have engaged in at least 25 charging sessions at Schools Pilot sites. As illustrated in the right panel showing total consumption by driver, 12% (131) consumed more than 250 kWh. Sixty-five drivers (6%) have consumed more than 1,000 kWh, and 13 drivers (1%) have each consumed between 5,000 kWh and 15,000 kWh. Considering that a typical site consumes around 2 MWh monthly, this small number of drivers accounts for a large percentage of monthly energy consumption.

Figure 211. PG&E EV Charge Schools Pilot Driver Statistics for Drivers with Exceptional Utilization



Represents 100% of drivers

Represents 22% of drivers

Represents 12% of drivers

Highlights

- Data show relatively consistent yearly energy use and session counts though the size of charging sessions is increasing.
- Several sites show higher utilization than others likely from a driver base outside of the school staff charging overnight, on weekends, or both.
- Utilization at some sites is consistently low while others show slight growth.
- Over one-third of charging sessions are greater than 25 kWh and show yearly growth.

Petroleum Displacement

The Evaluation Team estimated pilot-induced petroleum displacement related to the 15 PG&E EV Charge Schools Pilot sites using three key pieces of information: electricity used for vehicle charging, EV annual miles traveled, and annual counterfactual vehicle fuel consumption. From this information we estimated the reduction in equivalent gallons of petroleum as a result of the PG&E EV Charge Schools Pilot. Table 87 presents petroleum displacement impacts for the EV Charge Schools Pilot sites through 2025, including estimated actual impacts for 2025, actual impacts for all sites in the pilot to date, and a 10-year forecast for all sites in the pilot to date.

Table 87. PG&E EV Charge Schools Pilot Petroleum Displacement

DAC	Usage (n=15)				Petroleum Displacement (GGE)		
	2025 Actual [a] (kWh)	PTD Actual [b] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
Inside DAC			376,139	679,270	9,529	17,334	70,171
Outside DAC			284,668	705,117	7,142	17,768	63,468
Total			660,807	1,384,387	16,671	35,102	133,639

[a] "2025 Actual" represents the data from all activated sites from pilot inception for the calendar year 2025.
[b] "PTD Actual" represents the data from all activated sites from pilot inception for all pilot years.

Highlights

- The 15 operational sites in the pilot to date collectively achieved an impact of more than 35,000 gallons of petroleum displaced, with over 49% located within DACs.
- Over a 10-year period, the sites will result in displacing over 133,000 gallons of petroleum.

Greenhouse Gas and Criteria Pollutants

The Evaluation Team calculated reduced emissions from displaced fossil fuel use from ICE vehicles that were not in service as a result of the PG&E EV Charge Schools Pilot. The Team first developed one ICE counterfactual, then calculated the emissions associated with this vehicle under conditions that otherwise matched the EVs to provide a baseline. Although EVs have no tailpipe emissions, the mix of generation sources from the electric grid used includes renewable as well as fossil fuel power to supply electricity to the charging stations, with the latter primarily responsible for emitting GHGs and criteria pollutants into the atmosphere.

Table 88 presents the GHG reduction resulting from the 15 activated EV Charge Schools Pilot sites in 2025 and the pilot to date as well as a 10-year projection, by impact location. Overall, the pilot has resulted in an 81% reduction of GHG emissions (284 MT total) relative to the counterfactual to date (352 MT total, not shown in table), with 50% of the impact within DACs.

Table 88. PG&E EV Charge Schools Pilot GHG Reductions [a]

DAC	Usage (n=15)				GHG Reduction (MT)		
	2025 Actual [b] (kWh)	PTD Actual [c] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
Inside DAC			376,139	679,270	81	141	630
Outside DAC			284,668	705,117	62	142	587
Total			660,807	1,384,387	144	284	1,217

[a] Columns may not sum to total due to rounding.
[b] "2025 Actual" represents the data from all activated sites from pilot inception for the calendar year 2025.
[c] "PTD Actual" represents the data from all activated sites from pilot inception for all pilot years.

Of the local emissions, the EV Charge Schools Pilot had the highest impact in reducing CO, resulting in an estimated reduction in the pilot to date of nearly 3,900 kg (Table 89).

Table 89. PG&E EV Charge Schools Pilot Local Emissions Net Reductions

Emissions	EY2025 Sites Annualized (n=3)			PTD Sites (n=15)	
	Inside DAC	Outside DAC	Total	Actual	10-Year Projection
PM_{10} (kg)	-	0.07	0.07	1.49	5.84
$PM_{2.5}$ (kg)	-	0.06	0.06	1.37	5.37
ROG (kg)	-	0.67	0.67	22.87	111.27
CO (kg)	-	28.70	28.70	808.56	3,898.75

Figure 212 shows the mix of electricity from the CAISO grid used to support the PG&E EV Charge Schools Pilot sites.[107] Based on the real-time grid conditions when EVs charged, the overall energy mix contained about 57% zero-emission or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 30% natural gas. With the CAISO grid adding more renewables to meet the Renewable Portfolio Standard, GHG and criteria pollutant emissions will continue to decrease.

Figure 212. PG&E EV Charge Schools Pilot Net Electricity Mix, Pilot-to-Date Sites

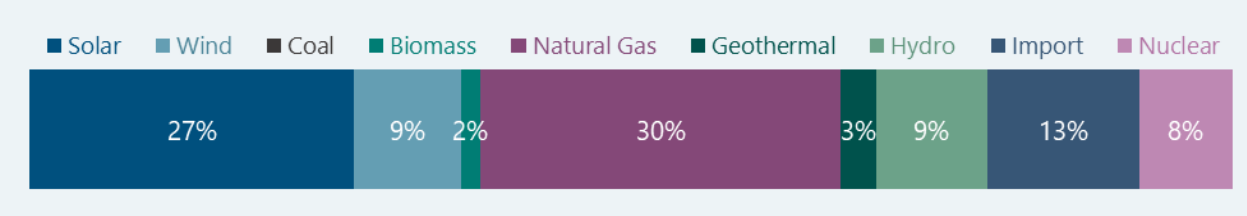
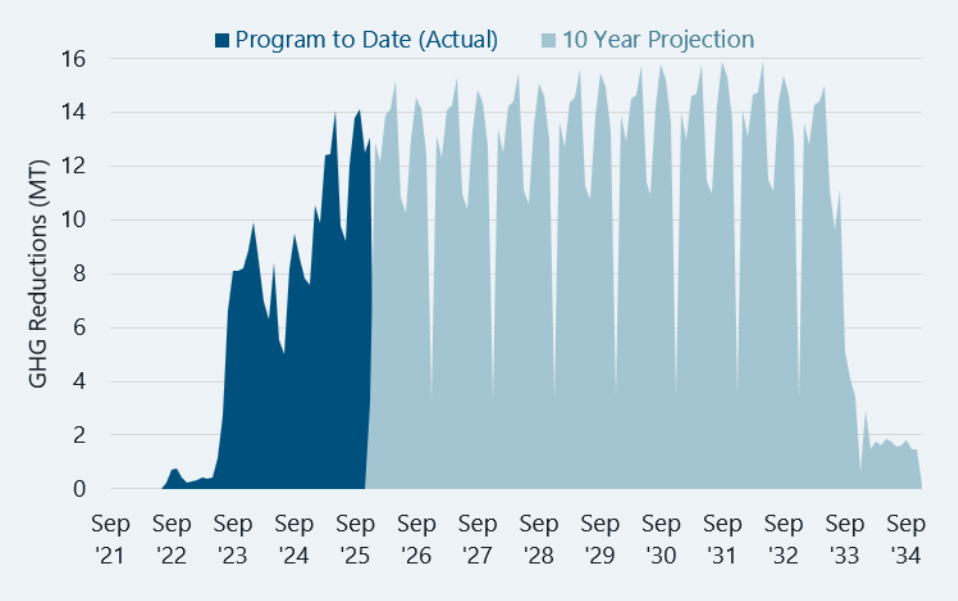


Figure 213 shows how GHG reductions from the EV Charge Schools Pilot have increased to date and how these reductions are expected to grow over time for all sites. The analysis period ranges from the date of activation for the first site in the pilot through the end of 2025. The analysis incorporates the net reduction (counterfactual emissions minus utility emissions) for each pilot site. Emissions reductions from the pilot to date are shown in dark blue, while anticipated benefits based on annualization appear in a lighter blue. Because sites begin operations at different times, the 10-year sunset for each appears as a gradual tapering of pilot benefits in 2032. This taper reflects that benefits are no longer counted after 10 years, although Schools will likely continue to use the infrastructure. While each year's operations appear similar, several key factors are driving slight variations; these include seasonality of utility generation sources (high Utility emissions appear as a dip on the curves), holidays occurring on weekends versus weekdays, and inaccuracies in predicted operations for sites that became operational late in 2025.

[107] The power associated with imports comes from a mixture of hydro, nuclear, and natural gas plants located outside the CAISO grid.

Figure 213. PG&E EV Charge Schools Pilot Historical and Forecasted GHG Reductions, Pilot-to-Date Sites



Highlights

- In 2025, the PG&E EV Charge Schools Pilot resulted in an 81% reduction of GHG emissions to date with 43% of its impact occurring within DACs.
- The greatest reduction in local emissions was for CO, with a projected 10-year period reduction of nearly 3,900 kg.
- Based on the real-time grid conditions when EV charging occurred, the overall energy mix contained about 57% zero-emission or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 30% natural gas.

Health Impacts

The Evaluation Team calculated public health impacts (as benefits and costs) of reductions in criteria pollutants from vehicle electrification. The pollutants included in the analysis are primary $PM_{2.5}$ and precursors of secondary $PM_{2.5}$, including NO_x, SO_2, NH_3, and VOCs. This analysis considered only tailpipe emissions reductions rather than full lifecycle emissions (such as power plant emissions). The Evaluation Team used the EPA's COBRA tool to evaluate the health benefits associated with the emissions reductions. COBRA estimates the county-level monetized benefits for the county where emissions are reduced. The tool also estimates monetized benefits for all counties in the United States (since emissions disperse beyond the source county), although most impacts are felt in nearby counties, and the Team's analysis examines only California counties.

The morbidity-related monetary benefits the Evaluation Team estimated include avoided lost wages, avoided medical costs, and the money people are willing to pay to avoid an illness or condition like a respiratory disease. The Team measured these benefits in terms of the value of a statistical life associated

with premature mortality. COBRA reports both a low and a high impact for mortality, representing the uncertainties in the estimates.

The total value of the health benefits associated with the emissions reductions from activated PTD sites in the PG&E EV Charge Schools Pilot is between $5,895 and $8,408. Table 90 shows the cumulative health benefits in California for the pilot to date.

Table 90. PG&E EV Charge Schools Pilot California Health Benefits for PTD Sites in 2025

Health Endpoint	Change in Incidence (Annual Cases)		Monetary Value (Annual, 2025 Dollars)	
	Low	High	Low	High
Mortality	**< 0.000**	**0.001**	**$5,225**	**$7,738**
Avoided Medical Care				
Hospitalization, Respiratory	< 0.000	< 0.000	$1	$1
Hospitalization, Cardiovascular	< 0.000	< 0.000	$1	$1
Hospitalization, Other	< 0.000	< 0.000	$1	$1
ER Visits, Respiratory	0.001	0.001	$1	$1
ER Visits, Cardiovascular	< 0.000	< 0.000	$0	$0
Out of Hospital Heart Attacks	< 0.000	< 0.000	$0	$0
Nonfatal Heart Attacks	< 0.000	< 0.000	$9	$9
Stroke	< 0.000	< 0.000	$1	$1
Lung Cancer	< 0.000	< 0.000	$1	$1
Asthma	0.376	0.376	$301	$301
Hay Fever	0.015	0.015	$17	$17
Lost Productivity				
Minor Restricted Activity Days	0.145	0.145	$19	$19
Work Loss Days	0.025	0.025	$8	$48
School Loss Days	0.177	0.177	$310	$310
Total Health Effects	-	-	$5,895	$8,408

As part of this analysis, the Evaluation Team also examined health benefits within DACs, which may be disproportionately burdened by sources of pollution (including air pollution from ICE vehicles). Because COBRA estimates effects at only the county level, the Evaluation Team disaggregated health benefits by census tract using the relative population of each tract from the most recent ACS. For example, the Team allocated 10% of the value of the health benefits to a census tract with 10% of the county's population. The Evaluation Team then estimated the total benefits allocated to DACs and non-DACs.[108] This approach assumes that the benefits of emissions reductions are distributed evenly throughout the county. If the sites reside in DACs and the emissions reductions are greater in the tracts near the sites, this approach understates the potential benefit to DACs. Additional information about emissions dispersion within counties would provide more precise estimates of health benefits to DACs and non-DACs.

[108] DAC census tracts are defined as those included in the SB 535 Disadvantaged Communities List (2022), which includes DAC categories for CalEnviroScreen 4.0 Top 25%, CalEnviroScreen 4.0 High Pollution Burden Score and Low Population Count, and 2017 Disadvantaged Community (CalEnviroScreen 3.0 only).

Alameda County had the highest proportion of overall benefits with 14% of the total, followed by Contra Costa County (13%), Santa Clara County (13%), Sacramento County (10%), and San Joaquin County (10%). Overall, 18% of the benefits from pilot sites are in DACs.

Highlights

- The annual monetary health benefits from PG&E EV Charge Schools Pilot sites range from a low estimate of $5,895 to a high estimate of $8,408.
- Alameda County had the highest proportion of overall benefits with 14% of the total, followed by Contra Costa County (13%), Santa Clara County (13%), Sacramento County (10%), and San Joaquin County (10%).
- Overall, 18% of the health benefits are in DACs.

Utility Staff Insights

In addition to monthly check-in calls with key PG&E staff to discuss the status of the EV Charge Schools and Parks Pilots, the Evaluation Team conducted a close-out interview with staff in March 2026 to review overall pilot challenges and successes in 2025. The following section groups these challenges and successes into those that apply to both pilots and those that only apply to one pilot.

EV Charge Schools Pilot and EV Charge Parks Pilot

Starting in 2021 and continuing through 2025, PG&E staff reported a continued challenge of site construction costs exceeding expectations, driven by labor constraints, materials cost increases, and supply chain delays. As in 2024, PG&E staff also noted that both pilots have experienced delays in the construction timeline due to site hosts' constraints:

- **Construction Labor Costs and Supply.** Construction labor costs have increased more than expected (per the original Decision 19-11-017 from 2018). These issues impacted the EV Charge Schools Pilot in previous evaluation years. In 2025, PG&E staff carefully tracked the pilot's budget to avoid overcommitting remaining funds.
- **Timeline Constraints.** As in 2024, PG&E staff explained that site construction had been delayed for both the EV Charge Schools and Parks Pilots due to constraints of the site hosts. Schools typically plan work around holidays and summer breaks, and Parks generally avoid construction during the spring and summer months.

EV Charge Schools Pilot

Because most of the activity for the EV Charge Schools Pilot in 2025 was focused on construction and activation of the final sites, the primary challenges for the EV Charge Schools Pilot revolved around difficulties in promoting curriculum adoption and continuing to monitor the pilot's budget:

- **Difficulties in Promoting Curriculum Adoption.** PG&E staff designed the curriculum in 2022 in partnership with SEI and rolled it out fully in 2022 and 2023. Although teachers who received the curriculum generally understood and endorsed it, as in previous years, PG&E staff noted difficulties in promoting adoption in 2025 due to teachers having limited time to prepare and teach the curriculum. In 2025, PG&E staff continued to report little curriculum adoption.

Despite some project scope changes and budgetary concerns, PG&E staff reported a smooth year for the EV Charge Schools Pilot. PG&E was able to complete the final sites for the pilot, achieved a high proportion of sites in DACs with eight sites in DAC territories, successfully accommodated one site's need for redesigns, and started conducting data refinement and analysis activities:

- **Final Sites Completed.** Despite some timeline delays, PG&E was able to construct and complete the final three sites in 2025, reaching the goal of 15 sites and 90 ports. The EV Charge Schools Pilot also met its DAC goal, with 40% of sites located in DAC territory
- **Accommodating Redesign Needs.** One site experienced challenges with the customer's design plans. However, because the pilot is small with only 15 sites, PG&E staff were able to dedicate enough time with the site hosts to redesign the site so it could remain in the pilot. The site was successfully constructed and completed in 2025 without disrupting the pilot.
- **Data Refinement and Analysis.** As PG&E prepares for sunsetting of the EV Charge Schools Pilot, in 2025 staff began conducting data cleanup and analysis activities at completed sites. These activities will continue in 2026.

EV Charge Parks Pilot

In 2025, PG&E staff primarily focused on filing the three Advice Letters for the EV Charge Parks Pilot and securing permits and planning for construction of the three sites. Although construction is planned to start in 2026, PG&E expressed concerns about coordination with the DPR and permitting delays:

- **Coordination with the State Parks Department.** In 2025, PG&E staff experienced difficulties with identifying and connecting with the appropriate stakeholders at the State Parks Department. Staff also reported challenges with obtaining correct information about the sequence of steps of the permitting process. PG&E staff reported that inconsistencies and confusion over permitting have hindered the pilot's ability to secure the necessary permits, further delaying construction for the three sites.
- **Permitting Language.** In 2025, PG&E staff and the State Parks Department held discussions about Right of Entry (ROE) language and decided to create boilerplate language to be applicable across all sites. Once the ROE permits are in place, which is expected by the end of the third quarter of 2026, PG&E will have access to the land, and during the year these permits are active, PG&E will work on executing a long-term easement so that PG&E and the EVSP can continue to access the land. However, PG&E did not anticipate that the Parks department would require each of the six districts to contribute to the final development of the ROE language, which has caused further delays for the sites.

Despite some challenges with permitting, PG&E staff reported a successful year for the EV Charge Parks Pilot as the pilot plans for construction in 2026:

- **Approval of Three Advice Letters.** In 2025, PG&E filed and received approval for three Advice Letters: a Tier 1 letter about tribal site exclusions, a Tier 2 letter about the reallocation of DAC funds, and a Tier 1 letter to confirm the installation of DCFC and EVSP ownership of the chargers. This allowed staff to move forward with site planning for the remaining State Parks sites.

- **Site Addenda Executed.** With the approval of AL 7504-E, PG&E was able to execute the three remaining site addenda.
- **EVSP Agreement Secured.** PG&E staff successfully reached an agreement with an EVSP and has started conversations about the vendor's role and responsibilities. They also have clarified the ownership model for the chargers at Parks sites, which is that the EVSP will own the equipment.

Highlights

- **Schools and Parks:** As in previous evaluation years, site costs continue to be a challenge. Rising construction labor and equipment supply costs, along with participant preferences for equipment such as DCFCs at Parks Pilot sites, drove up site costs.
- **Schools**: Despite cost strains and low curriculum adoption, PG&E finished construction on the remaining Schools sites while accommodating site-specific redesign needs and maintaining a close focus on optimizing the budget.
- **Parks:** In 2025, the final three site addenda's were executed. Despite some challenges with coordinating with State Parks and confusion over the permitting process, PG&E was able to begin planning for construction in 2026.

5.2.3. Lessons Learned

EV Charge Schools and Parks Pilots

Despite continued site cost challenges, program staff has worked diligently to mitigate costs. PG&E launched the EV Charge Schools and Parks Pilots during the COVID-19 pandemic, a period marked by significant economic disruption across nearly every market. Beginning in 2021, staff reported that site construction costs consistently exceeded expectations because of labor constraints, rising material prices, and supply chain delays. These cost increases were substantial enough that the estimates used in Decision 19-11-017, which established the Schools and Parks Pilots and their funding levels, no longer reflected actual implementation costs. Staff noted that construction labor and material costs have continued to rise as anticipated, affecting the EV Charge Schools Pilot in prior evaluation years and potentially constraining Parks Pilot construction in 2026. PG&E staff have identified several strategies over the past four years to help mitigate site cost pressures. In 2025, staff closely monitored the program budget to avoid overcommitting the remaining funds. PG&E also began discussions to clarify EVSP's role and responsibilities and confirmed the ownership model for chargers at Parks sites, under which the EVSP will own the equipment, to mitigate O&M exposure for the Utility.

Schools Pilot

Upon completion of the three 2025 sites, PG&E staff successfully met the Pilot's DAC, port, and site goals per se reasonableness. Despite some schedule delays, PG&E staff successfully supported construction of the final three EV Charge Schools Pilot sites bringing the pilot to 15 activated sites and 90 L2 charging ports. The 15 activated sites represent 68% of the pilot's per se reasonableness goal of 22 sites. The 90 installed L2 ports exceed the pilot's minimum per se reasonableness goal of 88 ports and represent 68% of the maximum goal of 132 ports. While no sites activated in EY2025 were in a DAC, the pilot is still meeting its DAC goal, with 40% of activated sites in the program to date located in DACs.

PG&E EV Charge Schools Pilot has a nominal but growing influence on neighborhood EV adoption. In 2025, the EV Charge Schools Pilot increased the number of operational sites by three to bring the pilot-to-date total to 15. Since its inception, the EV Charge Schools Pilot has contributed to the EV adoption of 41 EVs for households neighboring the infrastructure.

The EV Charge Schools Pilot sites are helping to displace petroleum, reduce GHG and local emissions, and achieve nominal health impacts overall and within DACs. The PG&E EV Charge Schools Pilot sites to date have displaced over 35,102 gallons of petroleum, with 49% within DACs. The pilot to date has resulted in an 81% reduction of GHG, with 40% of the reduction occurring within DACs. These sites all positively contributed to lowering local emissions, with CO showing the most prominent projected reductions of nearly 3,900 kg over a ten-year period. Overall, 18% of the health benefits of the pilot sites are in DACs, and the total monetized health benefits range from $5,895 to $8,408.

Utilization of Schools Pilot sites is rising, with a growing number of sessions and increases in total consumption and demand. Three new sites were activated in the activated in the PG&E Schools Pilot, with a total of 144 kW of new capacity installed in EY2025, bringing total installed capacity to 633 kW in the program to date. Overall energy consumption increased 48%, rising to more than 200 MWh in EY2025, up from 150 MWh in EY2024. Nearly 19,600 charging sessions have taken place in the pilot to date, with approximately 40% of sessions occurring in EY2025. Monthly energy consumption rose steadily throughout EY2024, from approximately 15 MWh in January to 23 MWh at the end of the year, with dips in consumption in the summer months, coinciding with breaks in the school year. The amount of energy consumed per charging session has increased year over year, with over one-third of charging sessions in EY2025 dispensing 50 kWh or more. Demand peaked at 161 kW in EY2025, similar to a peak of 169 kW in EY2024. Charging activity outside of school hours at some sites, including on the weekends, indicates that sites are supporting the local community in addition to school employees.

Parks Pilot

PG&E staff made meaningful regulatory progress on the EV Charge Parks Pilot, but challenges persist. In 2025, staff successfully secured an agreement with an EVSP, providing greater clarity on charger ownership at Parks sites and executed three site addenda following approval of AL 7504-E. PG&E and the State Parks Department also discussed ROE language for each site, and the department decided to develop boilerplate language for use across all sites and an execution process.

Construction is expected to begin in 2026, but coordination and permitting issues delayed progress during the year. Specifically, PG&E staff reported continued difficulties identifying and connecting with the appropriate stakeholders at the State Parks Department, as well as challenges obtaining accurate information about the permitting process and the required sequence of steps. These inconsistencies and uncertainties hindered the pilot's ability to secure permits, delaying construction for the three sites.

Despite the implementation challenges, PG&E characterized 2025 as a productive year for the EV Charge Parks Pilot because these regulatory and contractual milestones positioned the program to move into construction in 2026.

5.3. EV Fast Charge Program

5.3.1. Overview

This overview provides a detailed description of the PG&E EV Fast Charge program; summaries of the program implementation process, performance metrics, materials, and budget; and a timeline of major milestones. Following the overview are detailed findings, highlights, and lessons learned.

Program Description

Per Decision 18-05-040, PG&E staff designed the EV Fast Charge program to support the installation of DCFCs at high-priority locations to encourage transportation electrification and minimize grid impacts. PG&E staff designed the program to support PG&E customers and EV drivers in general by providing fast charging make-ready infrastructure. Specifically, staff designed the program to help meet a portion of PG&E's estimated need for fast chargers in its service area by 2025; reduce driver range anxiety; and increase access to charging for all customers, especially those who lack ready access to home charging, need EVSE in transportation corridors for longer trips, or participate in ridesharing. In 2022, PG&E staff revised the original goal of 52 EV Fast Charge sites to between 30 and 40 sites and revised the port count forecast to between 156 and 200 to reflect rising costs per site. PG&E staff met with the CPUC Energy Division in February of 2022 to discuss the revision, which the CPUC accepted.

Original EV Fast Charge Targets

- 52 sites
- 25% in DAC locations

2022 Revised EV Fast Charge Targets

- 30 to 40 sites
- 25% in DAC locations

Through the program, PG&E provides turnkey make-ready EVSE that includes design, permitting, construction, and installation of all electric infrastructure from the Utility connection point to the charger stub. PG&E owns and maintains the infrastructure on the Utility side of the customer meter (electrical infrastructure to the meter panel), also known as TTM infrastructure. PG&E also designs, constructs, installs, owns, and maintains the customer side of the meter infrastructure (electrical infrastructure from the panel to the EV charging interconnection point), also known as BTM infrastructure but will not install, own, or maintain DCFCs. The program design provides multiple business models and flexibility for site hosts and operators: PG&E's customer of record at fast charge sites may be the site host, an EVSP, or another third party. To be eligible for the program, a site must be available 24x7 and must install chargers with a minimum output of 50 kW. Customers are required to cover the cost of the charger, installation, and all ongoing O&M related to the charger for a minimum of five years from the time of activation. To encourage equitable EVSE installation, sites located in DACs are eligible for a rebate of up to $25,000 for EVSE.

EV Fast Charge Design Goal

Support installation of DCFCs at high-priority locations.

Implementation

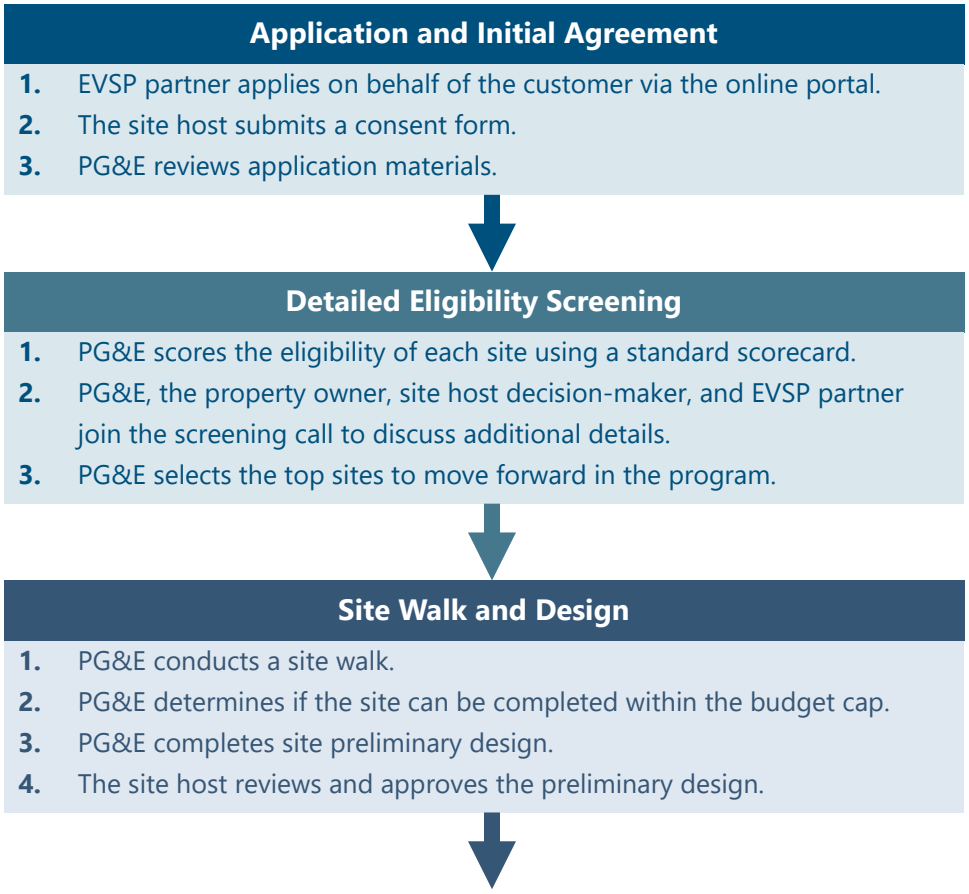
Most site solicitations for the program occurred in 2019 and 2021. In 2023, staff analyzed the program's budget and determined that it was projected to be underspent. Staff then conducted an additional partial solicitation targeting customers who had already engaged with the program and were likely to execute

contracts quickly. As a result, in 2024, PG&E extended an existing contract to add four more sites to the program and continued to track the budget closely to ensure that the remaining budget would cover all of the sites.

In general, PG&E uses an online application platform to facilitate the selection process. The application portal requests detailed information about the site, the site host, and the EVSE owner. This information allows PG&E to verify basic eligibility requirements, conduct initial scoring against the program's scorecard, and start infrastructure assessments. As part of the eligibility screening process, PG&E staff also conducts phone screenings with each potential site host. Over time, staff have refined the process to ensure that site host decision-makers (not just site contacts) are included in these calls.

Starting in 2022, PG&E allowed site hosts to contribute funding if the site exceeded PG&E's funding limits. After an EVSP engages with a potential customer, the implementation process begins, as detailed in Figure 214.

Figure 214. PG&E EV Fast Charge Program Implementation Process



Contracting

1. PG&E issues a contract.
2. The site host reviews and commits to the contract.
3. PG&E finalizes site design.

Construction and Activation

1. PG&E and construction contractor host a preconstruction meeting.
2. EVSP installs and activates DCFCs.

Program Performance Metrics

The Evaluation Team reviewed sites participating in the PG&E EV Fast Charge Program and analyzed them by program status. Table 91 provides the count of sites by completion status in EY2025 and for the program to date.

Table 91. PG&E EV Fast Charge Program Complete Site Count by Status

Site Status	EY2025	Program to Date
Utility Construction Complete	5	36
Activated	3	32
Operational	3	32
Closed Out	10	32

In EY2025, all three sites activated in the EV Fast Charge Program became operational. Two of the three (67%) EY2025-activated sites are located inside DACs, as shown in Figure 215. PG&E did not sign additional customer contracts in EY2025, leaving the total at 39 contracts to date.

Figure 215. PG&E EV Fast Charge Program EY2025 Activated Charging Sites

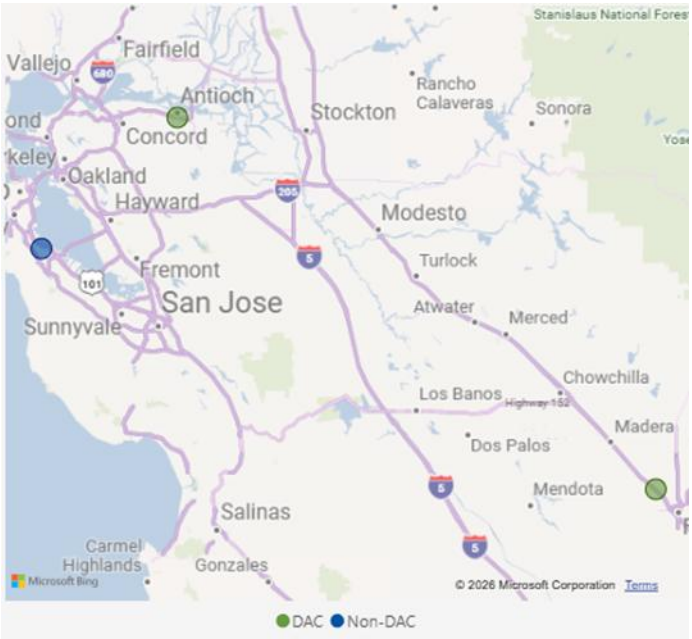


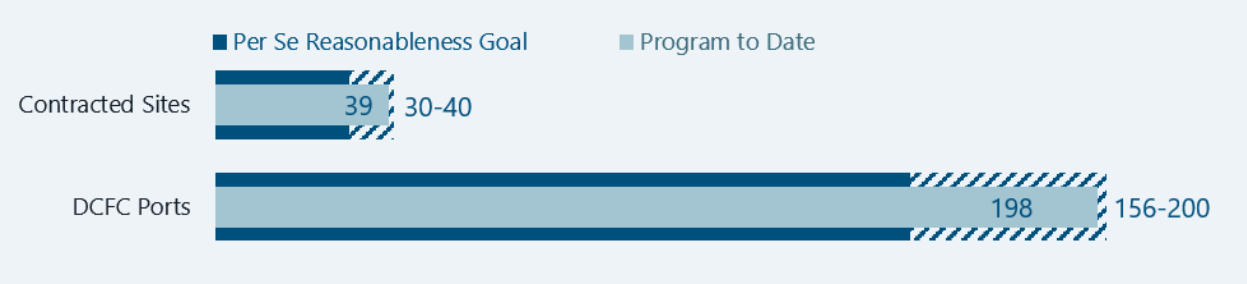
Table 92 presents site-level data for the PG&E EV Fast Charge program, showing DAC status and the number of DCFC ports for the activated sites in EY2025 and the program to date. In EY2025, 67% of activated sites were in a DAC, bringing the cumulative percentage of DAC sites to 56%, which exceeds the program's per se reasonableness DAC goal of 25%. The program deployed 16 additional DCFC ports in EY2025, increasing the total number of DCFC ports installed to 168. The number of installed ports at program sites range from four to eight.

Table 92. PG&E EV Fast Charge Program EY2025 and PTD Activated Site Data

EY2025			Program to Date		
Number of Activated Sites inside DAC	Number of Activated Sites outside DAC	Number of DCFC Ports	Number of Activated Sites inside DAC	Number of Activated Sites outside DAC	Number of DCFC Ports
2	1	16	18	14	168

As shown in Figure 216, the 32 activated sites in the PG&E EV Fast Charge Program achieve 100% of the program's per se reasonableness minimum goal of 30 sites and 80% of the program's maximum goal of 40 sites. There are 168 DCFC ports installed at the 32 activated sites, which meets 100% of the program's per se reasonableness minimum goal of 156 charging ports and 84% of the program's maximum goal of 200 ports. The 39 customer contracts signed to date could satisfy 98% of the maximum site goal and could host 204 DCFC ports, meeting 100% of the program's maximum DCFC port goals.

Figure 216. PG&E EV Fast Charge Program Site and Port Per Se Reasonableness Goal Progress



Hashed lines indicate that the number of contracted sites in the program to date is in the range of 30 to 40, and the number of DCFC ports in program to date is in the range of 156 to 200.

The CPUC established six phases in the program timeline per the SB 350 reporting template. Table 93 shows the median number of calendar days per phase for EY2025 and PTD activated sites. For EY2025 sites in the EV Fast Charge Program, the median number of calendar days per program phase ranged from 59 days for construction to 498 days for design and permitting. In general, median durations across program phases for EY2025 activated sites were significantly longer than those for PTD activated sites, with the exception of site assessment and construction.

Table 93. PG&E EV Fast Charge Program, Median Calendar Days per Phase

CPUC Program Phase	Median Calendar Days	
	EY2025 [a]	Program to Date [b]
Application Review	159	74
Site Assessment	89	58
Contract Issuance	294	80
Design and Permitting	498	482
Construction Complete	59	59
Activation	269	54

[a] "EY2025" represents the data for the sites activated in 2025.

[b] "Program to Date" represents the data from all activated sites from program inception for all program years.

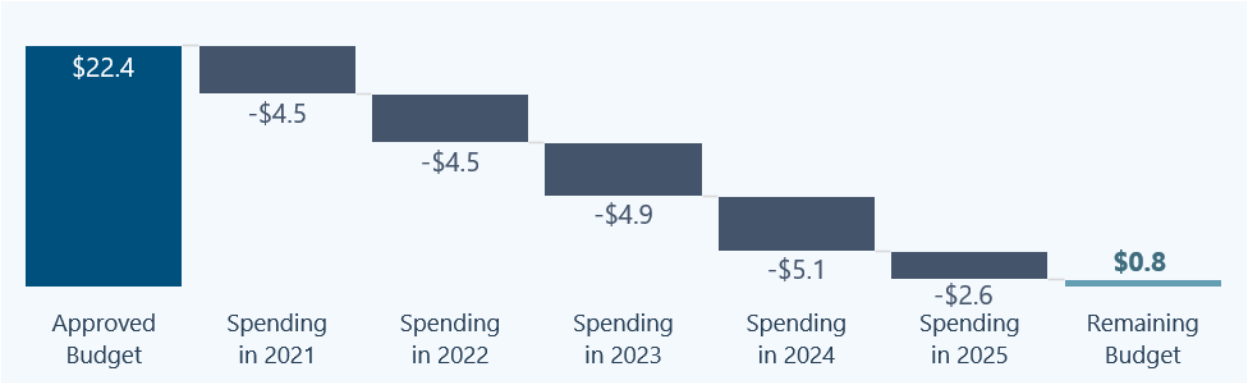
Program Materials Summary

PG&E did not develop any new program materials for the EV Fast Charge program in 2025.

Budget Summary

As shown in Figure 217, from program inception through 2025, PG&E spent $21.6 million of the $22.4 million EV Fast Charge program budget. Program spending totaled $2.6 million in 2025.

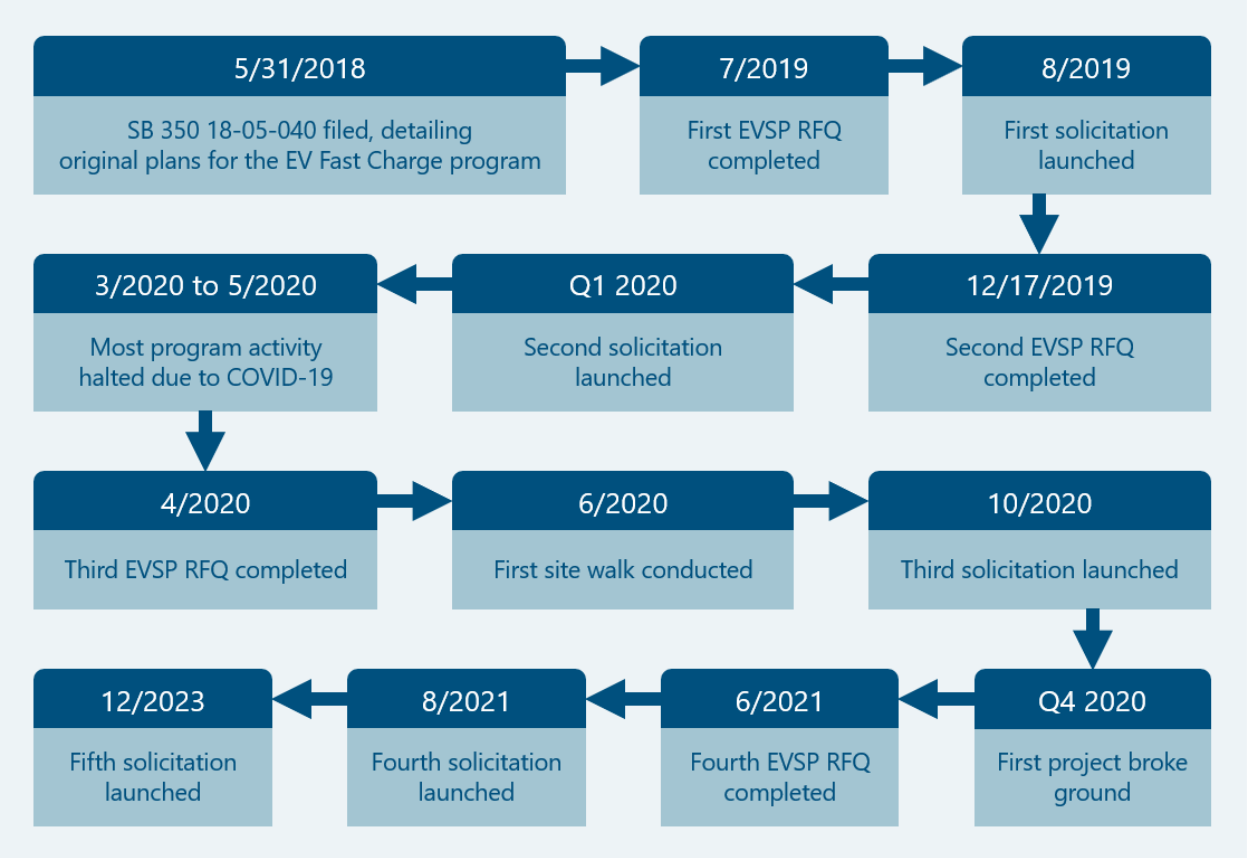
Figure 217. PG&E EV Fast Charge Program Budget (Million USD) as of December 31, 2025



Timeline

In 2025, program staff focused on constructing and activating sites, and there were no new regulatory milestones. Figure 218 illustrates key milestones from program inception to the end of 2025.

Figure 218. PG&E EV Fast Charge Program Key Milestones



5.3.2. Findings

This section provides findings from analyses of incremental EV adoptions, site visits and site costs, grid impacts, petroleum displacement, GHG and criteria pollutant reductions, health impacts, and from insights collected during Utility staff interviews.

Table 94 summarizes key impact parameters for EY2025 and the program to date. Annual estimates of impacts are provided for metrics calculated as part of the impact evaluation. The table also provides estimates of impacts across all sites included in the program population through the end of 2025.

Table 94. PG&E EV Fast Charge Program Impacts Summary

Impact Parameter	EY2025 Sites [a]	EY2025 Percentage in DAC	PTD Actual	PTD Actual Percentage in DAC
Population of Activated Sites	3	67%	32	56%
Sites Included in Analysis	3	67%	32	56%
Charging Ports Installed	16	63%	168	56%
Electric Energy Consumption (MWh)		42%		52%
Petroleum Displacement (GGE)	5,724	42%	752,311	51%
GHG Emissions Reductions (MT) [b]	47.2	42%	6,187	51%
PM_{10} Reduction (kg)	0.28	42%	31.68	52%
$PM_{2.5}$ Reduction (kg)	0.26	42%	29.13	52%
ROG Reduction (kg)	2.86	42%	491.72	51%
CO Reduction (kg)	122	42%	17,316	51%

[a] Energy consumption, petroleum displacement, and emissions reductions are based on annualized data. Program-to-date results are based on actual data (see *Appendix B* for details).

[b] GHGs include CO_2, CH_4, and N_2O multiplied by their respective GWP as defined by IPCC AR5 (see *Appendix B* for details).

Incremental EV Adoption

There are two main channels through which the availability of public charging networks may affect EV purchases. The first is a network effect, where EV owners gain increased access to public charging stations due to their placement at destinations such as workplaces, commercial establishments, schools, and parks. The Evaluation Team expects the availability of EV charging equipment at convenient locations (for midday charging away from home) to increase the convenience of owning an EV (such as by lessening range anxiety) and to increase the probability of EV ownership. The second channel is a neighborhood effect on drivers who live near public EV charging stations. The Evaluation Team expects the availability of nearby charging infrastructure to reduce the cost of EV ownership by providing alternatives to home charging. The Team expects that public EV charging will have the most impact on residents of multifamily buildings, many of whom will have limited access to EV charging equipment, and on residents of low-income households that may be unable to afford home EV charging equipment. Public charging access may boost EV ownership through both channels and that there may be positive interactive effects between the channels that boost the overall impact of public charging networks. The Evaluation Team focused on analyzing the second channel. We will analyze the impacts for the first channel separately when the data become available.

The Evaluation Team estimated the effect of public charging stations on EV adoption for neighboring populations with a two-stage analysis. In Stage 1, we looked at the historical impacts of public EV charging on vehicle ownership. See *Appendix B* for the details of the Stage 1 analysis.

Using the impact estimates from the Stage 1 analysis,[109] the Evaluation Team estimated the impact of PG&E investments in public charging on EV ownership. By the end of 2025, 32 charging stations in PG&E's EV Fast Charge program were active. The Evaluation Team estimated the impact of these stations on annual EV registrations and on cumulative EV registrations.

Based on the composite measure of public charging access, the Evaluation Team calculated the change in public charging access resulting from PG&E's investments for each CBG where those investments affected access. As shown in Table 95, the average change in access per affected CBG in the program to date was nearly five, while the average increase in the number of chargers (ports) was about four. In the 2020 baseline year, the average normalized EV annual registrations in affected CBGs were approximately 65 per 1,000 households.

Table 95. PG&E EV Fast Charge Program Summary Statistics of Effects on 85 Affected CBGs

	Change in Composite Measure of Access [a]	Change in Number of Chargers [a]	Normalized Annual EV Registrations [b]	Number of Households [c]
CBG Mean	4.86	3.7263	65.39	485.10
Standard Deviation	(3.19)	(2.92)	(77.96)	(318.88)

These values are averages for the CBGs whose access to public charging was affected by PG&E's investments.

[a] Change in composite measure of access and number of chargers is from 2020 to 2025.

[b] Normalized annual EV registrations are average annual values in the affected CBGs in 2020 per 1,000 households.

[c] Number of households is based on 2015–2019 ACS.

The Evaluation Team estimated the impact of PG&E'S EV Fast Charge investment on neighboring EV ownership[110] by combining the OLS and IV-2SLS regression estimates of the impact of public charging access from Stage 1 with the estimates of the CBG changes in public charging access and household counts. The impacts of PG&E's investments in fast charging on EV registrations depend on the extent to which the investments increased access in affected CBGs and the number of households in the CBGs.

[109] The Stage 1 analysis used vehicle registration data from 2015 to 2023, the most recent period with complete information at the CBG level. The EY2025 estimates assume the impact of Utility-specific stations remains unchanged over time, which may not reflect actual market conditions and technological changes in 2025.

[110] In Stage 1 the Evaluation Team estimated the impact of public EV charging access on EV ownership. Stage 2 built on the Stage 1 analysis and was an attribution analysis for Utility specific investments. A notable benefit of this approach is that it can be applied to evaluations of other programs increasing EV charging access as well, which ensures methodological consistency.

Table 96 presents the estimates of annual and cumulative EV registrations attributable to PG&E's EV Fast Charge program investments. Based on the OLS long differences model,[111] PG&E's investments in the EV Fast Charge program stations increased EY2025 annual EV registrations by nearly 14 vehicles and cumulative EV registrations by nearly 30 vehicles. Based on the IV-2SLS long differences model, PG&E's investments increased EY2025 annual EV registrations by approximately 27 vehicles and cumulative EV registrations by approximately 66 vehicles. The Evaluation Team prefers the IV-2SLS-based estimates because they account for the potential endogenous siting decisions of public charging (e.g., building public charging infrastructure in locations likely to have low or high rates of EV adoption). These estimates assumed that the 32 activated EV Fast Charge sites operate for a full year.

Table 96. PG&E EV Fast Charge Program Effects of Utility Investments on 2025 and PTD EV Registrations

	EY2025		PTD	
Analysis Model	OLS	IV-2SLS	OLS	IV-2SLS
Increase in EV Registrations	13.85	26.94	29.54	66.49
Standard Error	(2.06)	(4.01)	(2.82)	(5.68)

The Team estimated the OLS long differences using data for all CBGs in the analysis sample and estimated the IV-2SLS long differences for CBGs in the 20 largest California cities. The long differences are annualized eight-year estimates. For each affected CBG, the Team calculated the increase in annual registrations as the product of the regression-based access coefficient divided by eight, multiplied by the change in composite public charging access from utility investments (between baseline 2020 and EY2025), multiplied by the number of CBG households (in thousands). Robust standard errors clustered at the CBG level are in parentheses.

Both estimated EY2025 and program-to-date cumulative impacts of the EV Fast Charge program on EV registrations remain modest but show substantial growth compared with prior evaluation years. Across all estimated CBGs, the total annual number of EV registrations is about 5,558 (857 * 65.39), so the EY2025 impact of the EV Fast Charge program, based on the preferred IV-2SLS regression estimate, lifts EV registrations by 0.5%, and the program-to-date impact lifts EV registrations by 1.2%. Compared with EY2024, the percentage impact on EV adoption increased by more than 56%. This growth is primarily driven by the expansion of charging stations.

Highlight

- The model's output shows that the EV Fast Charge program may have contributed to the adoption by 66 EVs for households neighboring the infrastructure.
- EV Fast Charge program impacts on EV adoption remain modest but are growing rapidly.

[111] The long differences model estimates indicate the impact of public charging on EV registration over eight years. The Team annualized these estimates by dividing the results by eight.

Site Visit Findings

The Evaluation Team visited the three EV Fast Charge sites completed in EY2025. These three sites have a total of 16 DCFC ports and an installed capacity of 1,020 kW. This brings the total sites in the program to date to 32 with 168 DCFC ports and installed capacity of 13,290 kW. Figure 219 and Table 97 show the total number of ports and observed capacity for sites activated in EY2025 and in the program to date.

Figure 219. PG&E EV Fast Charge Program DCFC Ports and Capacity Observed in 2025 and in the Program to Date

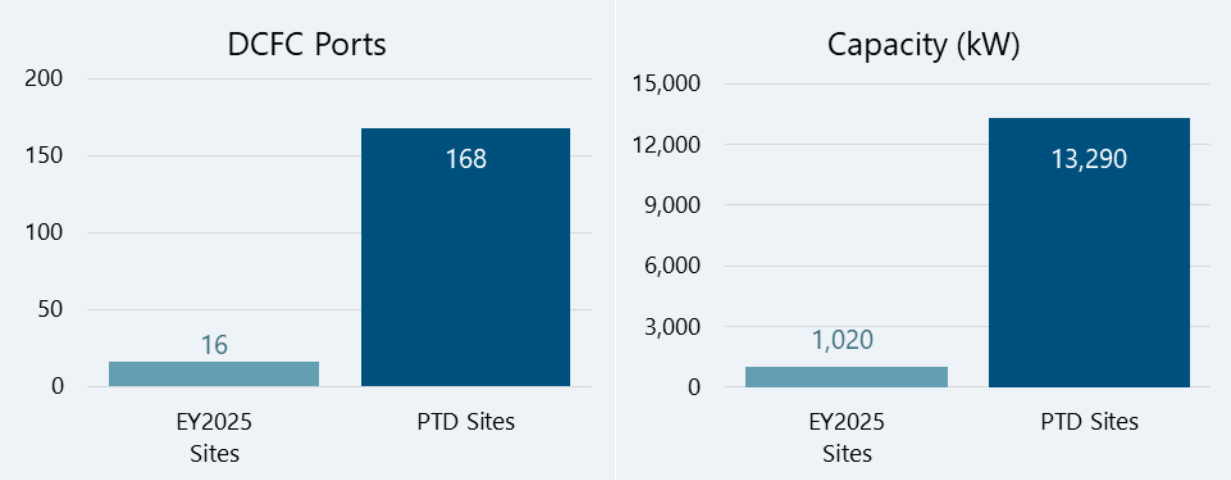


Table 97. PG&E EV Fast Charge Program Summary of Ports and Capacity Observed during Site Visits

Site Visit	Number of Sites	Ports	Installed Capacity
EY2025 Sites	3	16	1,020
PTD Sites	32	168	13,290

Two of the three EY2025 sites the Team visited are located around the San Francisco Bay Area and one is in the Central Valley. Two sites are at a gas station with a convenience store and one is in a public library parking lot that also serves nearby restaurants and stores. Two of the sites are classified as suburban and one as city. Figure 220 shows the distribution of the 32 PTD sites according to NCES Locale classifications.[112]

[112] A locale classification is a general geographic indicator that describes the type of area where a school is located. The National Center for Education Statistics (NCES) classifies all territory in the United States into four types: City, Suburban, Town, and Rural. nces.ed.gov/programs/edge/Geographic/LocaleBoundaries

Figure 220. PG&E EV Fast Charge Program Count of Site Urbanization



During site visits, the Evaluation Team documented construction layouts, connector types, parking elements, and information about the physical chargers including any available pricing information. One site was activated at the end of the first quarter of 2025, but after some usage in the second quarter the site has since been offline due to a disagreement between the station owner and the equipment/network service provider about who is responsible for the cost of replacing faulty equipment and utility bills when the equipment was out of service.

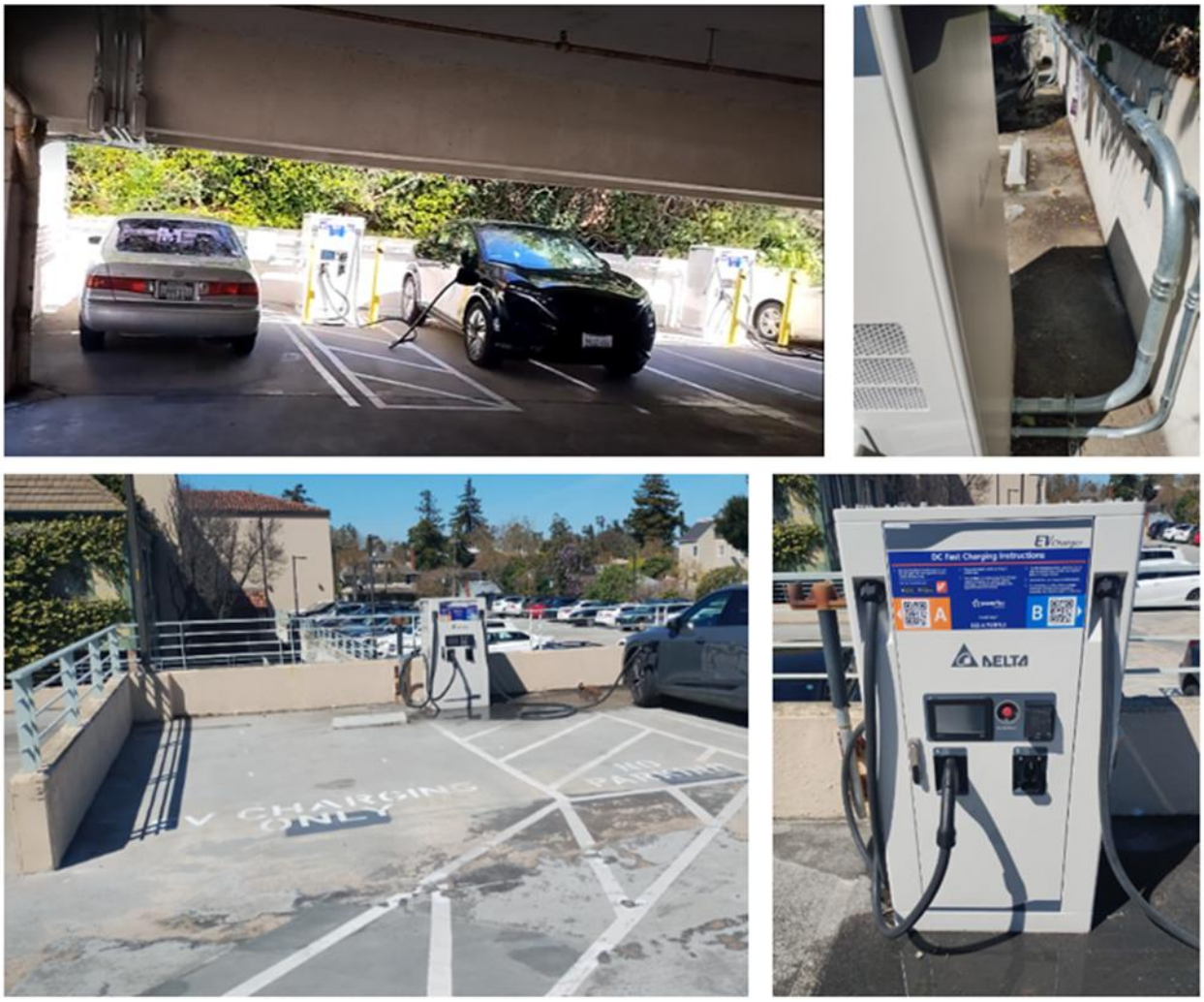
Charging speeds range from 100 kW to 180 kW per port for EY2025 activated sites. All three sites use dual-port DCFCs (examples are shown in Figure 221), which allow all available power to be delivered to one port to charge a single vehicle, or to split power between two ports when both are in use. This reflects a general increase in charging capacity, typically from 50 kW to 60 kW per port at older sites up to 180 kW to 350 kW per port observed in EY2024 and EY2025.

Figure 221. PG&E EV Fast Charge Program EY2025 Sites with Dual-Port 180 kW EVSE at Gasoline Stations



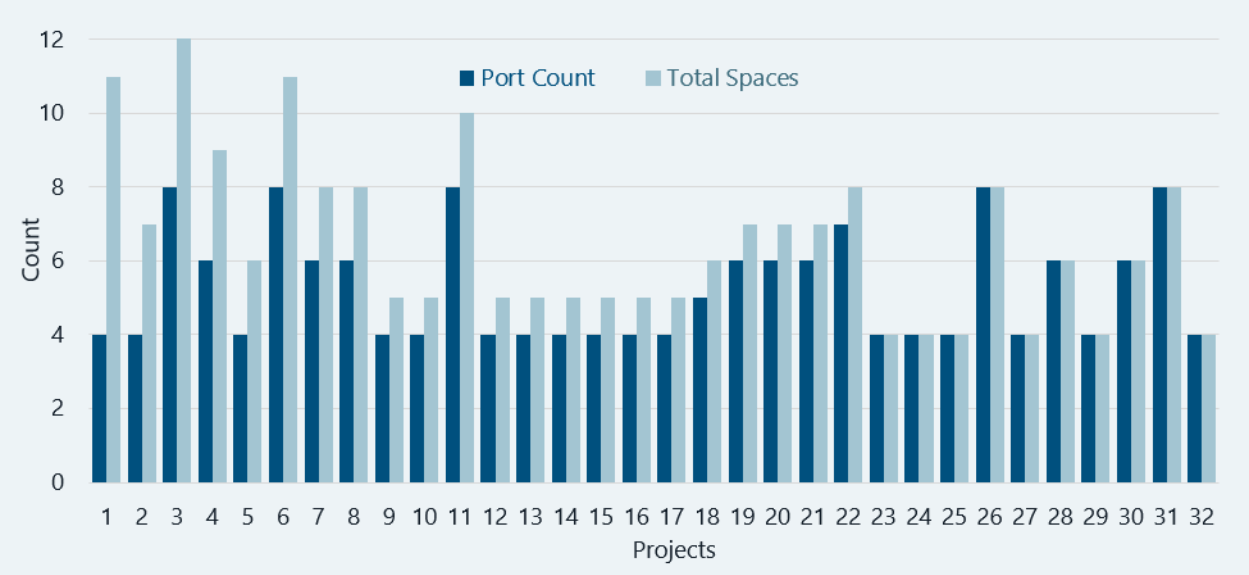
One site was a parking garage installation, which was unique as all the electrical conduit connecting the switchgear to the EV chargers was above ground as shown in Figure 222. While two of the chargers were adjacent, the third one was a story higher and several hundred feet away on a different corner of the parking garage.

Figure 222. PG&E EV Fast Charge Program EY2025 Site with Dual-Port 100 kW EVSE at a Public Parking Garage



Most of the current public DCFC site layouts have one port serving a dedicated parking space. To highlight the value of having multiple parking spaces within reach of cords, Figure 223 shows the number of ports and the number of spaces that can access these ports for the PG&E EV Fast Charge sites the Evaluation Team visited. As illustrated by the figure, most sites offer nearly a one-to-one ratio of parking spaces to charging ports (10 sites have no additional parking spaces within reach of charging ports, and 13 sites have one extra parking space). However, more than one-quarter of the sites have two to four additional parking spaces within reach of charging ports. This allows additional vehicles to use a charging port without moving the first vehicle, which can improve charger utilization and serve more customers as well as help compensate for out-of-service equipment.

Figure 223. PG&E EV Fast Charge Program Visited Sites
Charging Port Availability by Site for PTD Sites



The Evaluation Team reviewed the pricing structure available to EV drivers, including costs for idle time to encourage turnover, and strategies for encouraging charging when energy emissions and costs are low and discouraging charging when they are high (such as from 4 p.m. to 9 p.m.). PG&E rates offer the lowest cost of electricity daily from 9 a.m. to 2 p.m., but most sites set fixed prices for electricity. In addition, fewer than one-quarter of all activated sites (7 of 32) offer retail pricing to EV drivers based on TOU rates.

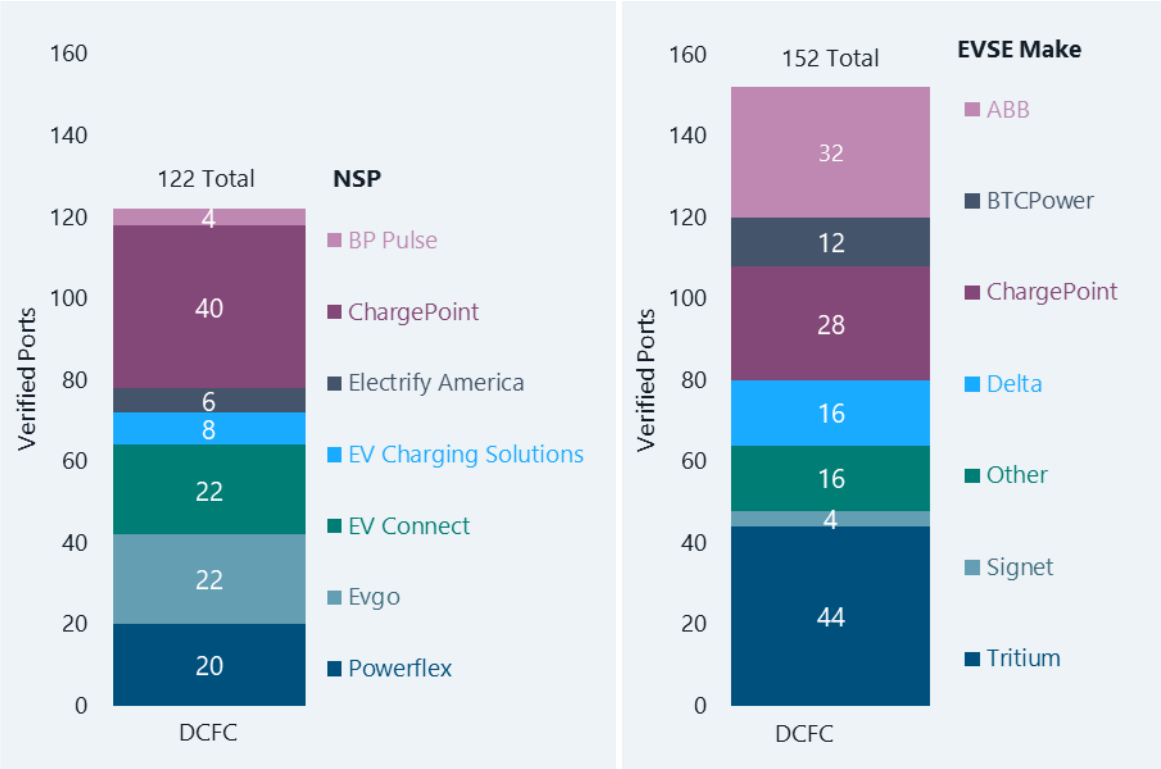
For the seven sites that offer TOU pricing for customers, price increases from the low to high TOU rate periods ranged from 10% to more than 100%. Six of the 32 sites also employed a flat per-session fee of $1.00, and one site with per-session fees also used a flat rate for energy. One operator of several sites within the program did mention that while they are not currently using TOU rates, they are considering using these rates in the future.

Most sites had posted energy pricing between $0.42/kWh and $0.69/kWh. Several network operators offer subscription plans that can reduce the effective cost to as low as $0.25/kWh. Subscription specials may reflect special programs such as for rideshare drivers and by some vehicle manufacturers with the purchase or lease of a new vehicle. It is not possible to determine how much charging was done using discounted subscriptions.

The Team observed idle fees at one-third of visited sites. These ranged from as low as $2/hour to as high as $60/hour (at $1/minute). High rates for idle time send a strong message to EV drivers to move their vehicle when charging is completed so that others can make use of the resource. One activated site exhibited pricing for energy delivery of $0.59/kWh and an idle parking time rate of $10/hour starting 10 minutes after charging completion. Though not pictured, these charging sessions most often had little to no idle time.

Site visits did not reveal any new NSPs or EVSE; all three sites were additional locations from existing NSPs (BP Pulse, PowerFlex, and EV Connect) and installed ABB and Delta chargers. The 32 activated sites in the program comprise seven NSPs and seven EVSE makes as shown in Figure 224.

Figure 224. PG&E EV Fast Charge Program NSPs and EVSE Makes for PTD Sites



Highlights

- The Evaluation Team visited all three EY2025 activated sites and observed 16 DCFC ports and 1 MW of installed capacity. The Team has visited all 32 PTD activated sites and has observed 168 DCFC ports and more than 13 MW of installed charging capacity.
- EY2025 sites continue to exhibit higher charging speeds than sites activated in previous years, ranging from 100 kW to 180 kW per port. All EY2025 sites have EVSE with two ports capable of power sharing or providing maximum EVSE rated power when only one vehicle is connected.
- Fewer than 25% of sites provide TOU rates to EV drivers to encourage consumption when electrical grid congestion and electricity generation emissions are low, such as in the early afternoon per PG&E tariffs. Charging data from sites that provide TOU rates to drivers suggest that EV drivers are modifying their charging behavior in response to TOU rates
- One-third of sites set idle fees to encourage turnover and improve access to charging ports.

Site Costs

The Evaluation Team conducted a cost analysis on the 32 activated EV Fast Charge sites with fully closed out finances as of December 31, 2025. The set of fully closed out sites is smaller than the set of activated sites because of the time lag involved in performing activities such as collecting receipts, paying invoices, and obtaining administrative approvals. Cost estimates presented here are in nominal dollars. The 32 sites all have DCFC ports, with an average of 415 kW of installed capacity and 5.3 ports per site.

Figure 225 shows the distribution of site-level costs for the 32 sites. The horizontal lines of the boxes show the 25th, 50th, and 75th percentile of sites; the X denotes the mean site cost; and the three panels are defined as follows:

- **Utility Infrastructure Costs.** Actual site installation costs borne by the Utility for both TTM and BTM (or the BTM incentive when the site infrastructure is customer-owned), including all capital and labor costs.[113] This does not include the cost of the EVSE equipment or installation.
- **Ratepayer-Funded Costs.** Actual site installation costs borne by the Utility, including all capital and labor costs of TTM, BTM (or the BTM incentive if the site infrastructure is customer-owned infrastructure), and EVSE rebate.
- **Estimated All-In Costs.** Estimated costs of installing the site borne by the Utility and the customer including all capital and labor costs. The value is calculated by summing actual TTM,[114] actual or estimated BTM,[115] and estimated EVSE costs.[116]

[113] Utility Infrastructure costs are the same as the Ratepayer-Funded Costs, except they do not include the EVSE rebates.

[114] The Utility pays 100% of the TTM costs and therefore reports actual TTM costs to the Evaluation Team.

[115] The Evaluation Team receives actual BTM costs for sites with Utility-owned BTM. In total, 86 of 160 sites with fully closed out financials have Utility-owned BTM. Other BTM costs were estimated by the Evaluation Team using the relationship between installed kilowatts and BTM from other sites with actual BTM costs.

[116] Because the Utility does not record actual EVSE costs, the Evaluation Team estimates all-in EVSE equipment costs using assumptions of $3,000 per port for L2 ports and $45,000 per port for DCFC ports.

Figure 225. PG&E EV Fast Charge Program Per-Site Costs Organized by Three Perspectives, Across 32 Closed-out PTD Sites

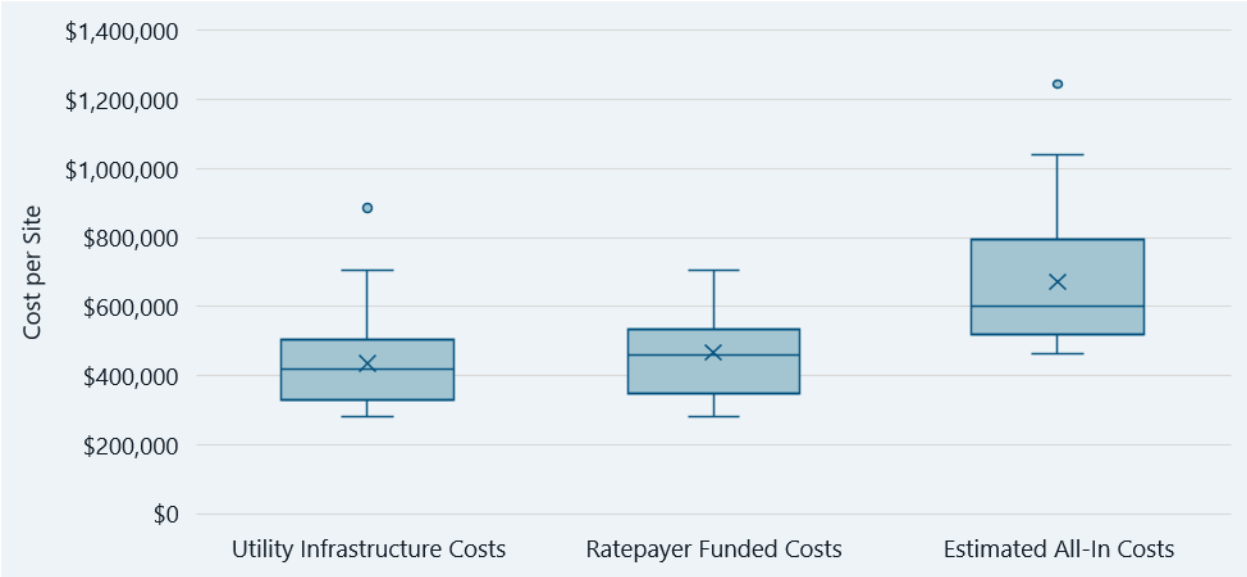
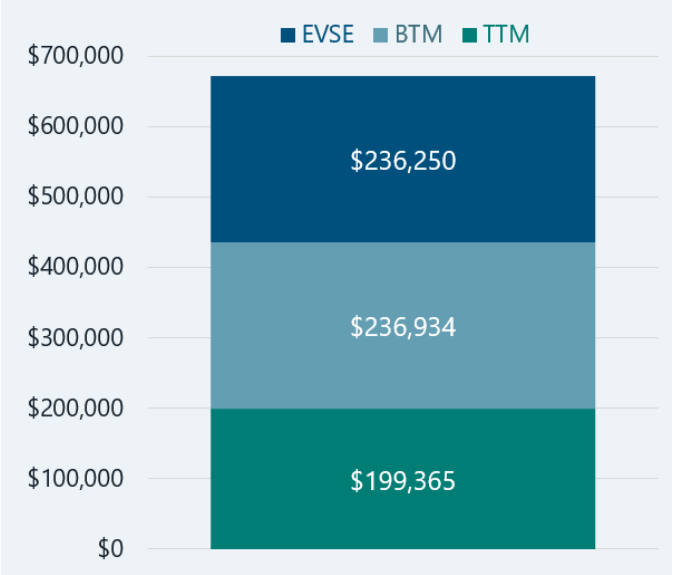


Figure 226 shows average estimated all-in costs for the 32 sites. BTM accounts for the largest cost across the sites, followed by EVSE, then TTM. Together, the average all-in TTM, BTM, and EVSE cost for PTD sites is $672,549 through 2025.

Figure 226. PG&E EV Fast Charge Program Average All-In Costs, Across 32 Closed-out PTD Sites



The costs in this figure were calculated by summing all TTM, BTM, and EVSE costs borne by PG&E and the customer and dividing by 32 sites. Sites with customer-owned BTM have synthesized BTM costs.

Figure 227 shows the distribution of Utility infrastructure costs (corresponding to the far-left panel in Figure 225) presented per site and per kilowatt. The average Utility infrastructure cost, including TTM and BTM borne by PG&E through 2025, was $436,299 per site, and $1,217 per kilowatt of installed charging capacity.

Figure 227. PG&E EV Fast Charge Program Utility Infrastructure Cost per Site and per Kilowatt Across 32 Closed-out PTD Sites



Highlights

- Estimated all-in costs paid by the customer and PG&E vary widely between sites, with an average of $672,549 per PTD site. On average, BTM was the largest cost across the sites, followed by EVSE and TTM costs.
- The average utility infrastructure cost for PTD sites borne by PG&E, including TTM and BTM through 2025, was $436,299 per site, and $1,217 per kilowatt.

Grid Impacts

The Evaluation Team determined grid impacts for the PG&E EV Fast Charge program based on the analysis of energy consumed by operational charging stations installed through the PG&E EV Fast Charge program through 2025.

Data Sources

The primary data source used in this section is energy usage data provided in regular 15-minute intervals from the AMI. Other data sources include customer bills, LCFS credit information, and data provided by NSPs. There are several important differences between AMI and NSP data. While AMI data reflect only energy usage, NSP data include energy usage, session start and stop time, the duration of a vehicle's connection to a charging port, the duration of a vehicle actively pulling power, and the specific port used for a session. An AMI meter does, however, track standing loads (such as those the EVSE uses for

communications, cooling, active power converters, solenoids, and screens), which NSPs typically cannot do. When AMI data are missing from the dataset, the Evaluation Team uses NSP data to fill the gaps.

Summary of Grid Impacts

Table 98 presents a summary of the estimated EV Fast Charge program grid impacts.

Table 98. PG&E EV Fast Charge Program Grid Impacts

Impact Parameter	Actual 2025 [a]	Actual PTD	10-Year Projection PTD
Operational Sites	3	32	32
Installed Capacity (MW)	1.0	13.6	13.6
Electric Energy Consumption, MWh			41,467
On-Peak (4 p.m. to 9 p.m.) MWh (and % of total)			N/A
Maximum Demand, MW (with date and time)	1.9 (7/13/25 8 p.m.)	2.0 (12/28/24 10 p.m.)	N/A
Maximum On-Peak Demand, MW (with date and time)	1.8 (5/16/25 4 p.m.)	1.8 (5/16/25 4 p.m.)	N/A

[a] Energy consumption, peak consumption, and demand data are based on PTD activated sites for calendar year 2025.

The remainder of this section offers detailed findings on actual consumption, demand, and charging session–oriented trends of the combined sites through EY2025.

Energy Trends

Three sites were activated in the EV Fast Charge Program in EY2025, bringing the total number of activated sites through the end of 2025 to 32. PTD sites in the EV Fast Charge Program reached total consumption of more than 5,500 MWh in EY2025, leading to a total of over 10,000 MWh for the program to date, compared with total consumption of just over 3,000 MWh in EY2024 and program-to-date consumption through 2024 of more than 4,000 MWh (Figure 228). Consumption has been impacted by vandalism (site hosts at multiple sites reported stolen cords) resulting in nearly a 20% reduction in portfolio consumption compared with around 500 MWh for each of the first six months of 2025.

Figure 228. PG&E EV Fast Charge Program Monthly Energy Consumption and Maximum Demand

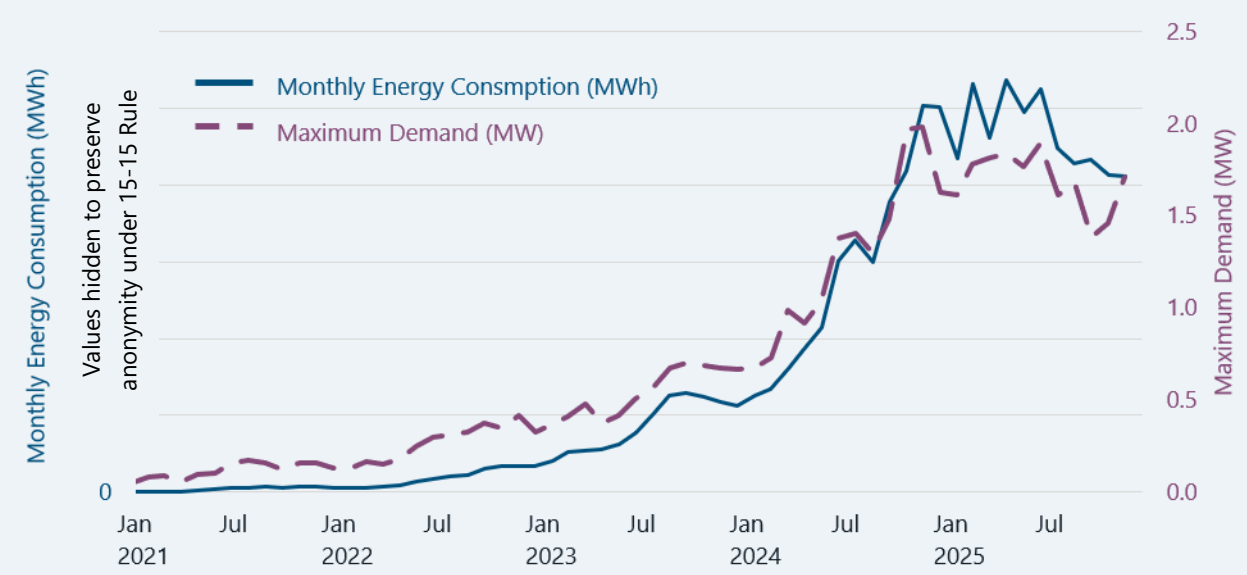


Figure 229 shows daily energy consumption and maximum demand of PTD sites. Daily maximum demand in the first half of 2025 hovered around 1,500 kW, peaking at just under 2,000 kW, and tapered for the second half of the year.

Figure 229. PG&E EV Fast Charge Program Daily Energy Consumption and Maximum Demand, PTD Sites

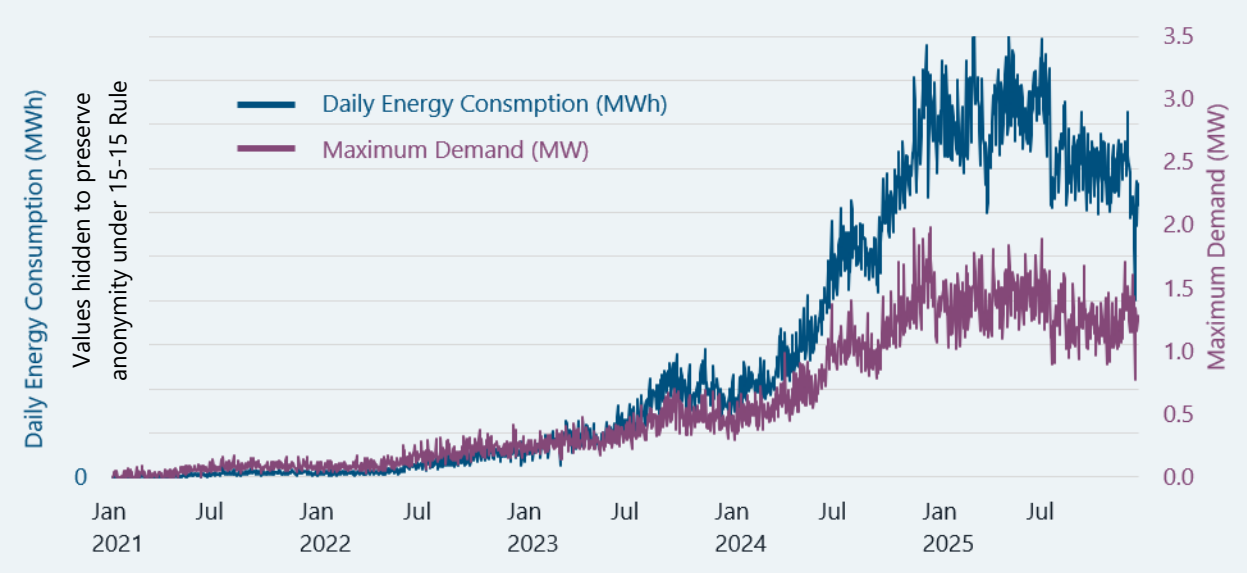


Figure 230 shows average weekday and weekend load curves in the fourth quarter of EY2025 for seven sites that provide TOU retail rates to EV drivers and 25 that do not. TOU rate sites appear to show two distinguishing characteristics that non-TOU sites do not display: higher overnight consumption and moderate load ramping at 9 p.m. that may indicate an effort by drivers to avoid high priced energy. Non-TOU sites show load ramping from around 3 p.m. to 5 p.m., an effect that utility TOU tariffs try to avoid.

TOU sites show more consistent charging between weekdays and weekends compared with non-TOU sites. Overall, the figure shows that TOU pricing seems to influence charging behavior of drivers, shifting consumption to lower cost time periods, though both TOU and non-TOU sites show substantial charging during peak periods.

Figure 230. PG&E EV Fast Charge Program Average Weekday and Weekend Q4 2025 Load Curves

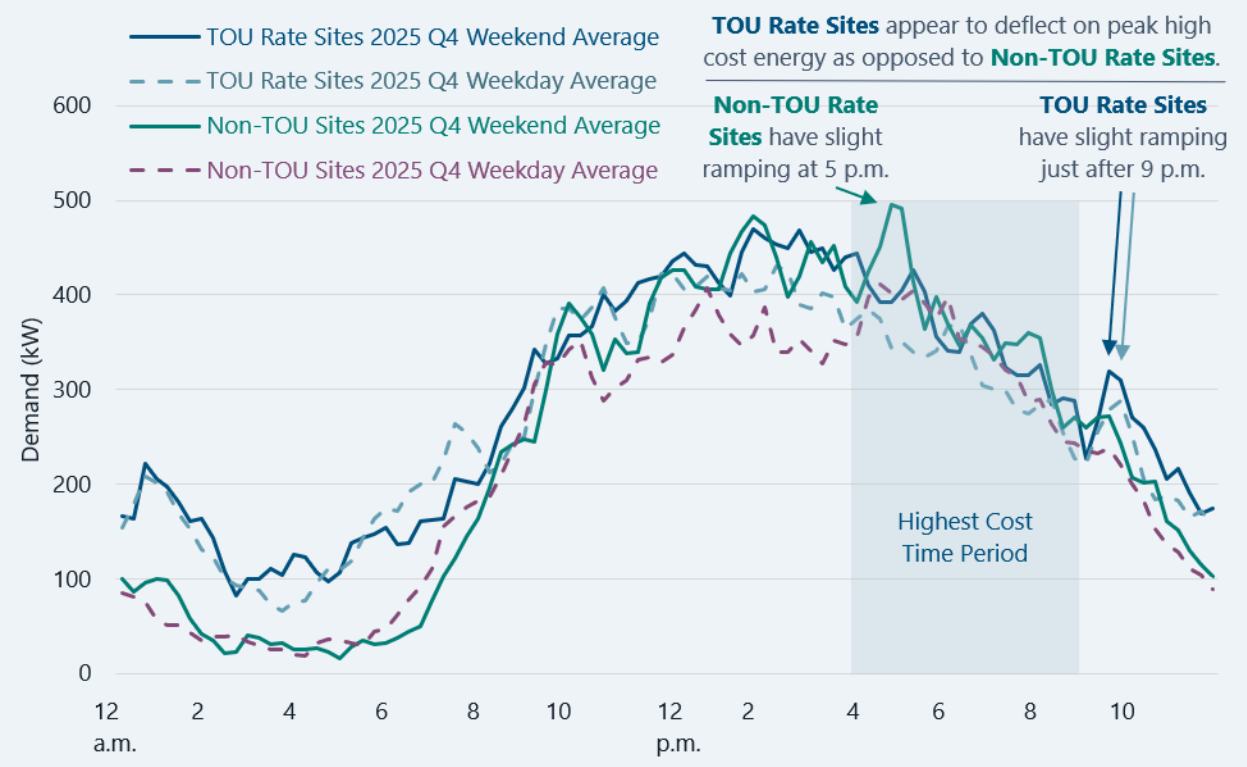
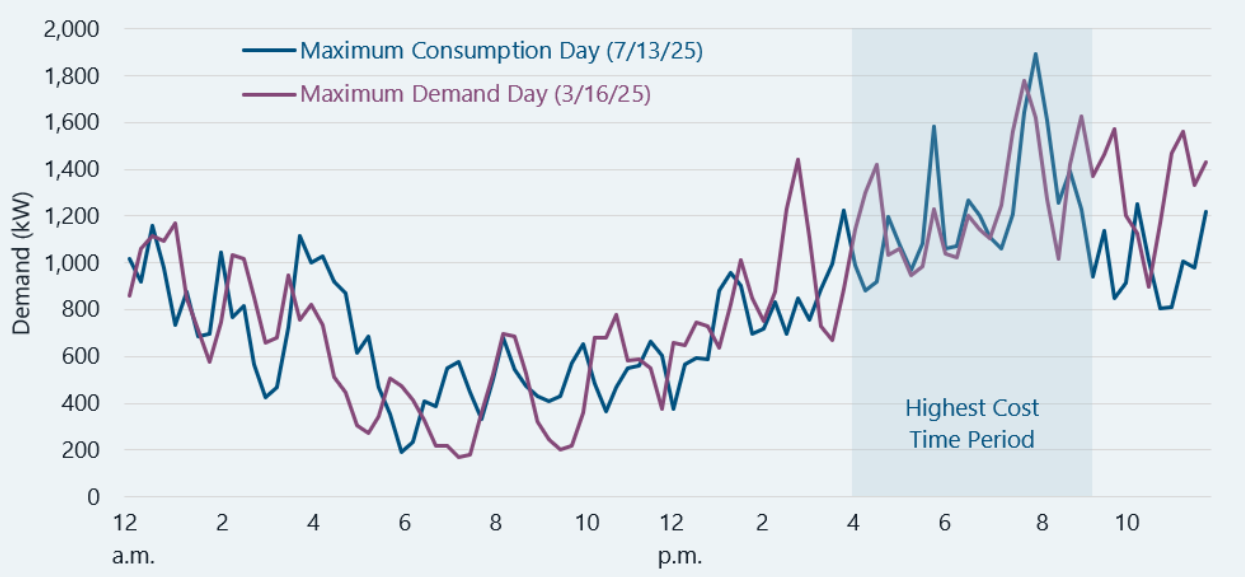


Figure 231 shows load curves of the highest overall days of demand and energy consumption for EV Fast Charge program sites. Both show maximum consumption of nearly 2 MW at a similar time of day (9 p.m.), coincident with lower electricity costs. This is a notable shift from EY2024, when peak demand occurred at 3 p.m. These two days each consumed around 20 MWh of charging, and both show significant overnight charging between 9 p.m. and 4 a.m.

Figure 231. PG&E EV Fast Charge Program Comparing Utilization Days



Usage Trends

With 11 sites having three or more years of operations and nine sites with two to three years of operations the Evaluation Team has had significant opportunity to review to what extent these sites may have stabilized or reached operational maturity. This section assesses program characteristics by comparing energy consumption, load factor (a measure of consistency of usage) and total charging sessions across sites. This analysis begins with a site's initial charging sessions, rather than when AMI data are first available, to eliminate early periods when chargers are powered up but not necessarily commissioned by their NSPs (i.e., in a testing period) or are not available for public use. Month zero is defined as the month when public access began.

The rate of growth in energy consumption and number of charging sessions may indicate to what extent that EV drivers are becoming aware of these sites and finding them helpful to their charging habits, or that the new charging availability is influencing drivers of conventional vehicles to transition to EVs.

Figure 232 shows monthly energy consumption for the 10 sites in the EV Fast Charge Program that consume the most energy, each of which has surpassed 12 MWh in monthly consumption. Some sites reached this level of consumption soon after becoming operational, while many others did not reach maturity until after twelve months of operation or later.

Figure 232. PG&E EV Fast Charge Program Monthly Energy Consumption for 10 Highest Utilization Sites

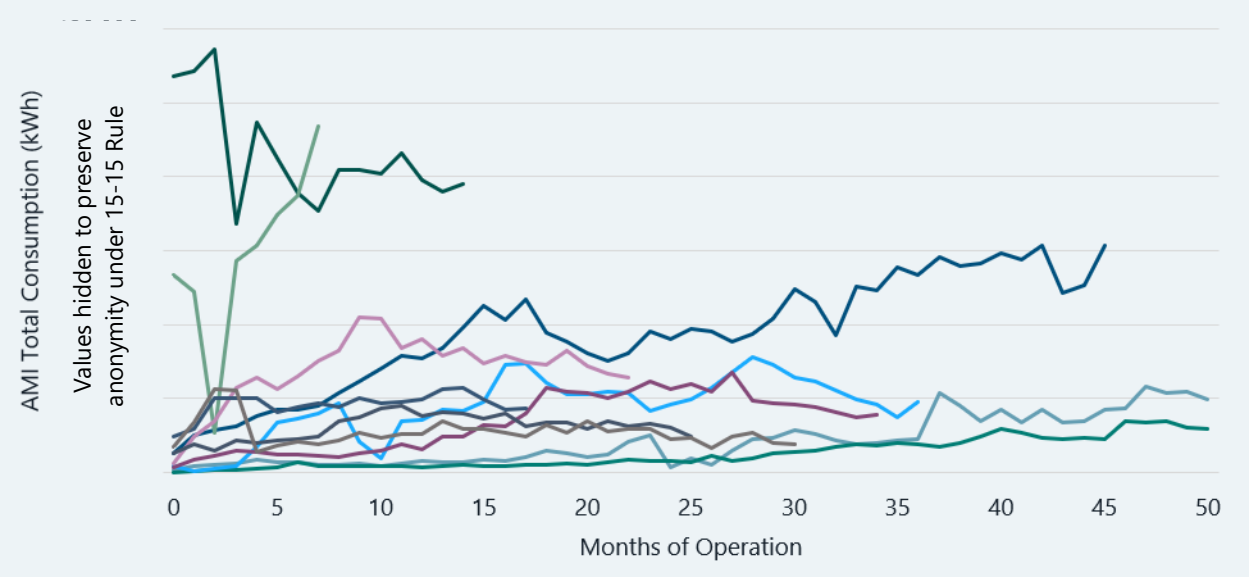


Figure 233 and Figure 234 show monthly consumption at the remaining 22 activated sites, grouped by whether or not they have achieved a 15% load factor (to improve data visualization). This allows analysis at the site level, rather than overall program performance. In past evaluation years, multiple sites had extended commissioning timelines, whereas only one site had delayed commissioning in EY2025.

The consumption for approximately half of the sites has remained below 5 MWh monthly with a few below 1 MWh. It may be worth reviewing these sites further in terms of geography, demographics, and pricing policy. As depicted in the *Site Visit Findings* section, retail prices for both flat and TOU rates range from $0.35/kWh to $0.75/kWh, and prices on the high side could deter repeat EV driver customers especially for sites with flat rates.

Figure 233. PG&E EV Fast Charge Program Monthly Energy Consumption (>15% Load Factor Sites)

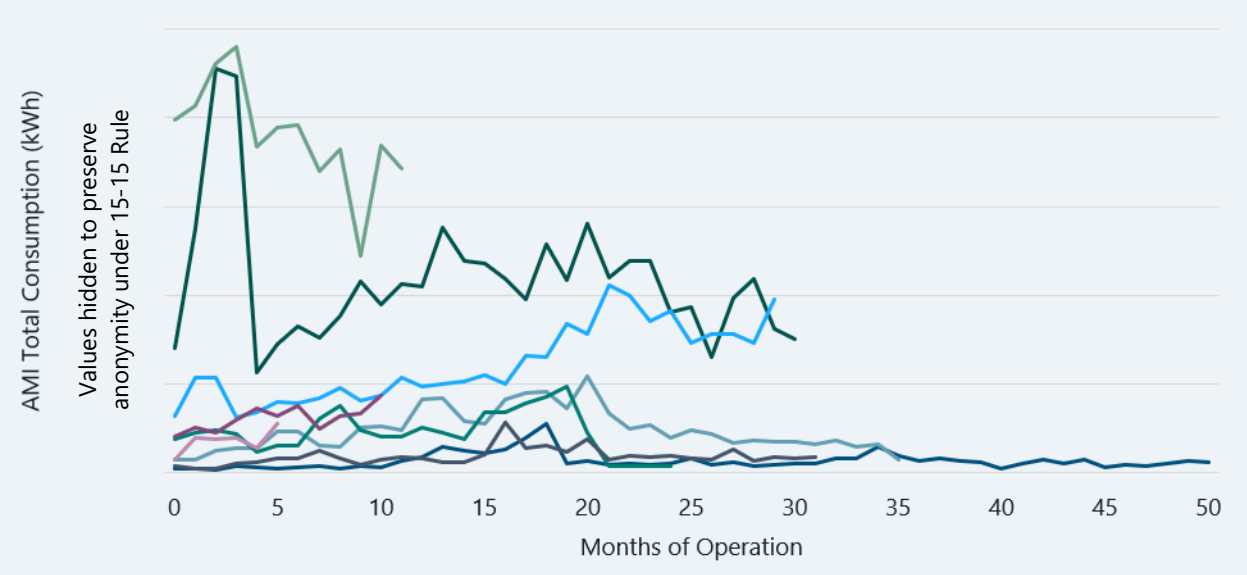


Figure 234. PG&E EV Fast Charge Program Monthly Energy Consumption (<15% Load Factor Sites)

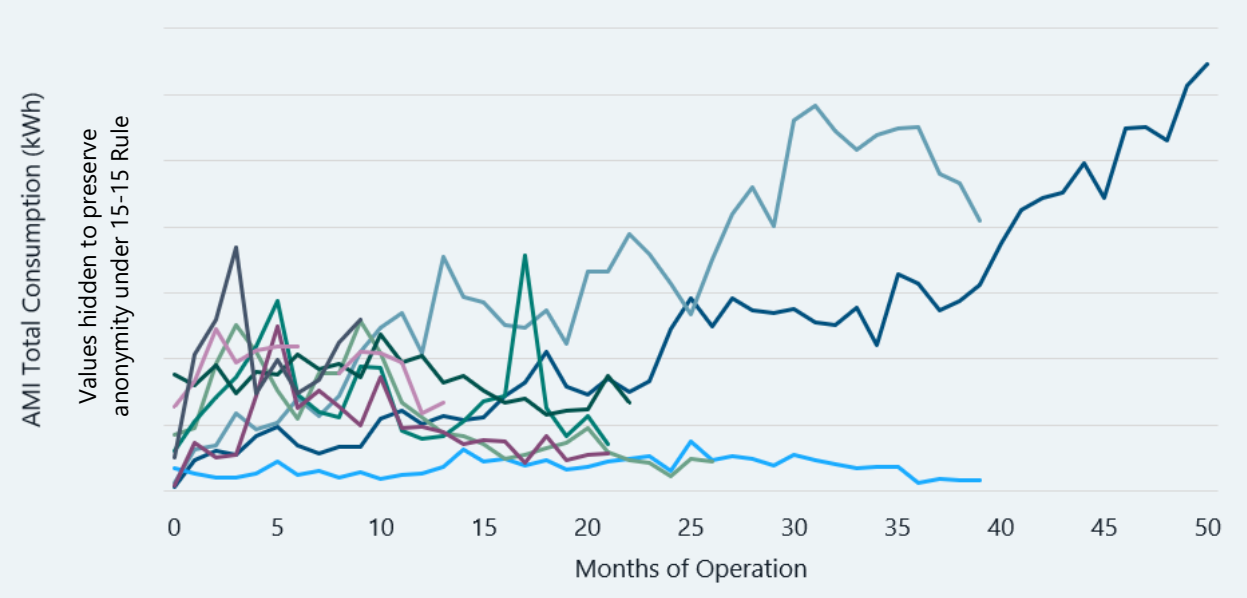


Figure 235, Figure 236, and Figure 237 show monthly load factor rather than consumption for the same three groups of sites. Load factor compares a site's actual monthly energy consumption to what its consumption would be if maximum demand were consistent throughout the entire month. For example, a constant maximum demand would result in a 100% load factor (which is highly unlikely in practice). Such data may help sites and Utility program staff better understand how long a site takes to reach full maturity and to what extent the power delivery capacity is being utilized. The ability to predict the level of demand for a site can also facilitate planning of future sites in terms of parking layout and charging capacity and may be helpful in developing utility tariffs.

Figure 235 shows that the 10 sites that consume the most energy generally show a growing load factor over their operational life, with most consistently over 20% and some reaching up to 40%. Figure 236 and Figure 237 show that for most of the remaining sites, utilization has remained low and inconsistent, with exceptions for a handful of sites that have slowly grown over time reaching the 10% to 15% range.

Figure 235. PG&E EV Fast Charge Program Monthly Load Factor for 10 Highest Utilization Sites

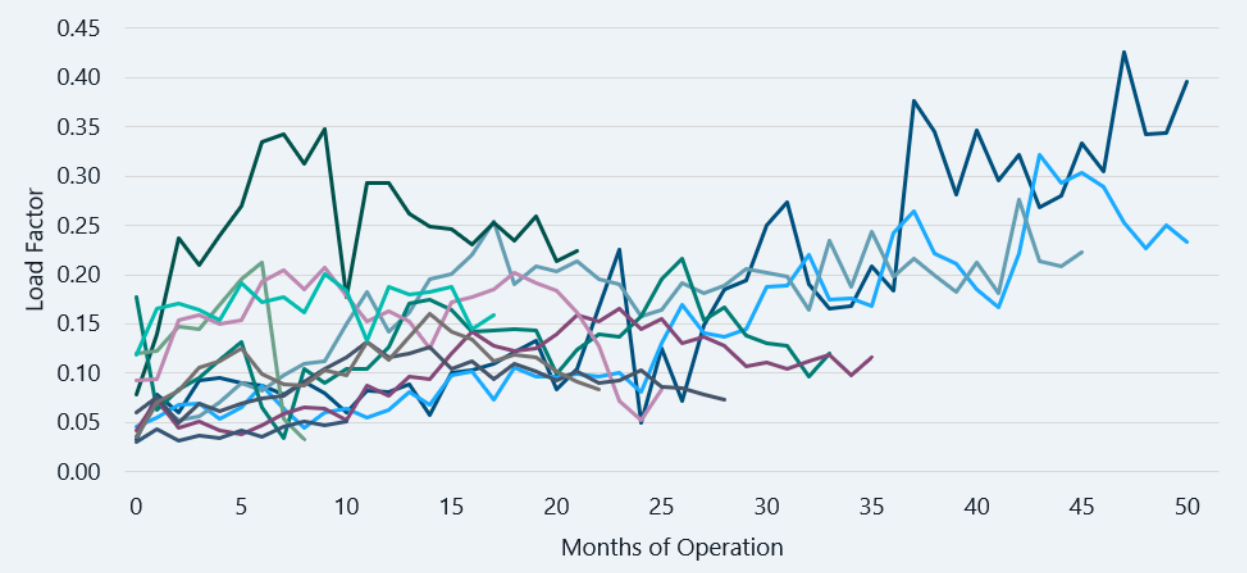


Figure 236. PG&E EV Fast Charge Program Monthly Load Factor (>15% Load Factor Sites)

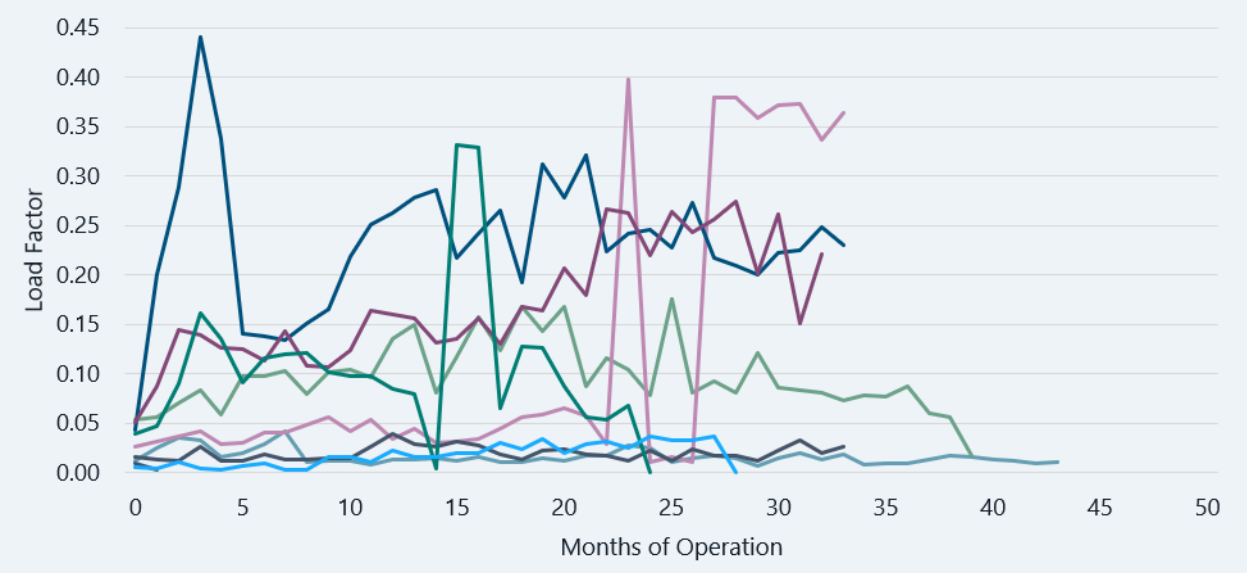
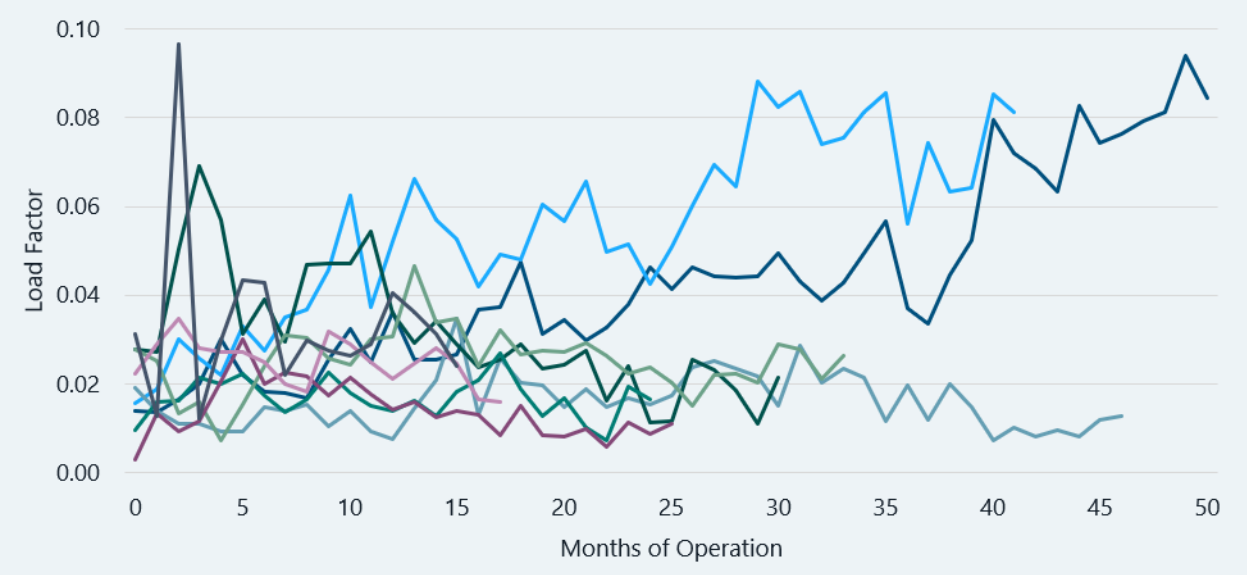


Figure 237. PG&E EV Fast Charge Program Monthly Load Factor (<15% Load Factor Sites)



High Utilization Sites: Weekend and Overnight Examples

Figure 238 compares EV Fast Charge sites that display what the Evaluation Team considers to be baseline operations with higher utilization sites that show overnight or weekend charging. The figure shows average demand in the fourth quarter of 2025, and is calculated on a per-port basis. All load curves display similar charging behavior, with an increase in demand beginning at 6 a.m., peaking midday between 12 p.m. and 4 p.m., and tapering in the evening. All of these sites appeared to provide 24-hour access based on site visits. Some of these sites have more consistent overnight usage than others. Both Strong Overnight curves (weekday and weekend) also show evidence of TOU pricing impacting EV drivers' choice of when to charge by ramping up after 9 p.m.

Figure 238. PG&E Demand per DCFC Port for Baseline and High Utilization Sites

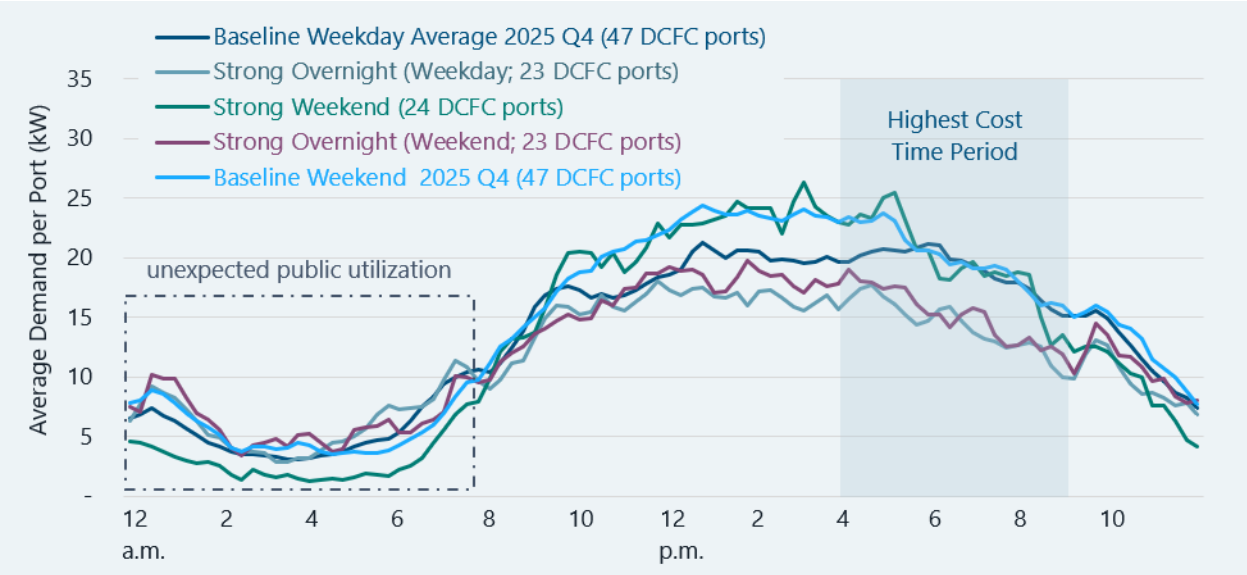


Figure 239 presents the number of daily charging sessions for EV Fast Charge program sites, which totaled approximately 122,000 sessions in EY2025, compared with 87,000 in EY2024. Days with the most sessions occurred in the first half of EY2025. However, the number of daily charging sessions fell by approximately 20% in the second half of the year, which may be attributable to vandalism or maintenance issues.

Figure 239. PG&E EV Fast Charge Program Daily Charging Sessions for PTD Sites

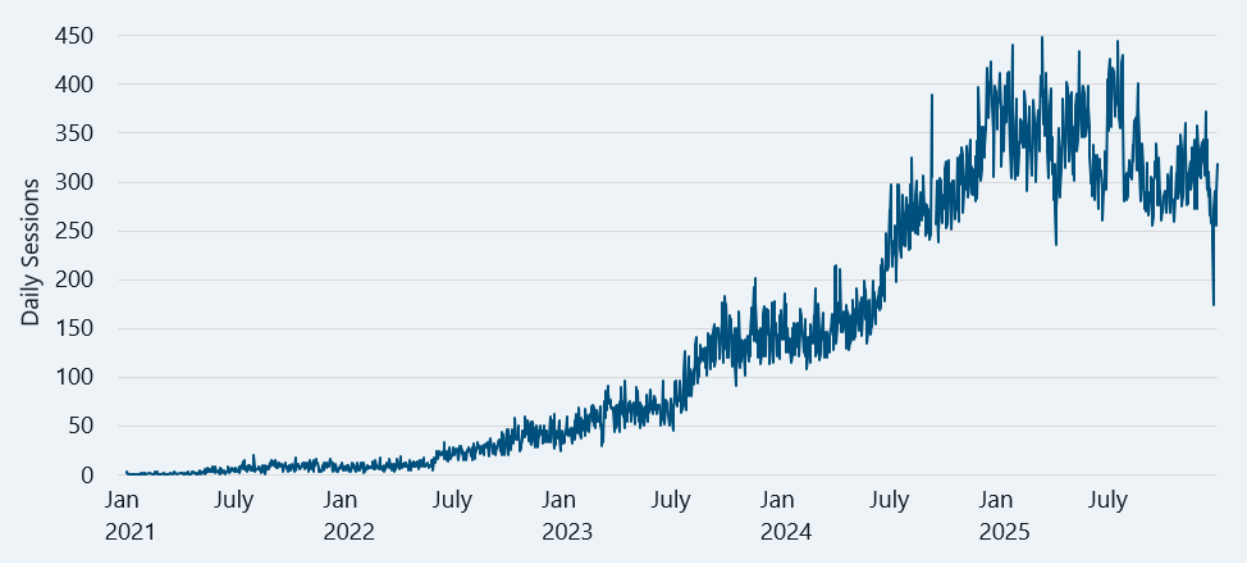


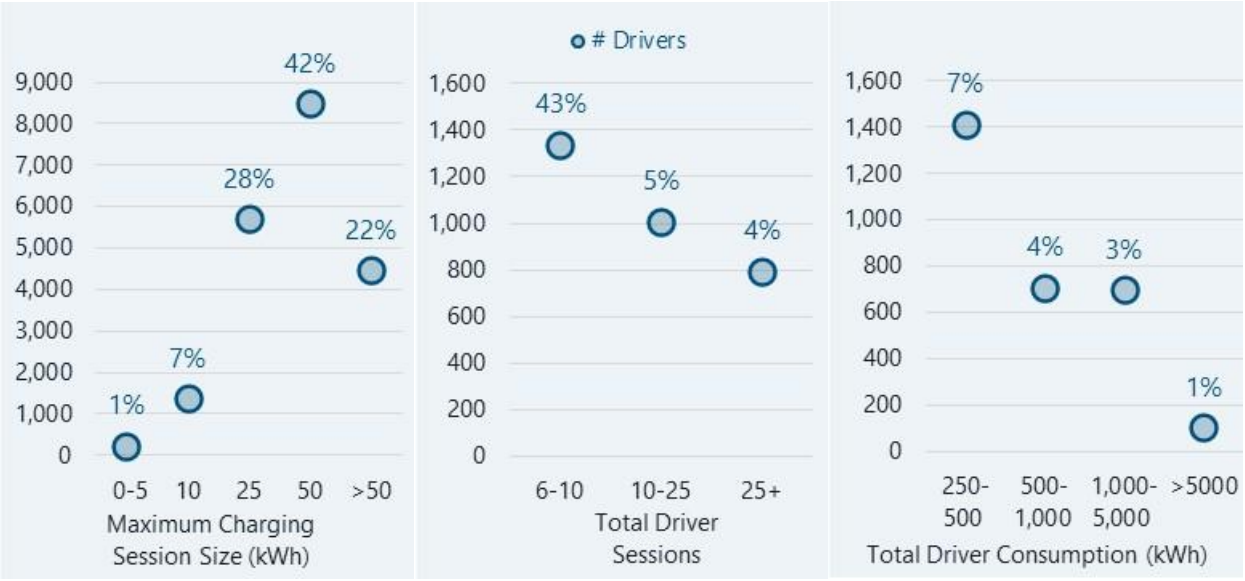
Figure 240 presents the distribution of charging sessions by size (kilowatt-hours consumed) by year for all PTD sites in the EV Fast Charge program. The Team did not include erratic charging sessions (below 1 kWh). As shown, the number of sessions of at least 50 kWh have increased significantly, while sessions below 12 kWh have decreased from prior evaluation years. Sessions between 25 kWh and 50 kWh have consistently represented approximately 40% of charging sessions for each of the last three years.

Figure 240. PG&E EV Fast Charge Program Charging Session Count by Consumption Size



Figure 241 highlights driver statistics. EV Fast Charge program sites appear to have supported over 20,000 unique drivers in the program to date, over 50% of whom are frequent users with six or more charging sessions. Approximately 120 of these drivers (<1%) are very frequent users showing 100 or more charging sessions. As shown, approximately 15% of drivers have consumed more than 250 kWh in the program to date. 800 drivers have consumed more than 1,000 kWh, while 100 drivers have each consumed between 5,000 kWh and 40,000 kWh. This highlights that EV Fast Charge sites have become reliable charging resources providing some insight into the user base.

Figure 241. PG&E EV Fast Charge Program Driver Statistics



Represents 100% of drivers | Represents 52% of drivers | Represents 15% of drivers

Highlights

- Some drivers appear responsive to retail TOU rates at DCFC sites based on load increases at 9 p.m. (when prices drop) for sites that offer TOU pricing to customers.
- Two-thirds of sites do not pass TOU rates onto drivers, limiting the influence of utility TOU tariffs on VGI, which may in turn limit the grid benefits the EV Fast Charge program provides.
- 50% of site users appear to be return customers with more than five charging sessions.
- One-third of sites have achieved at least 12 MWh in a month, though most sites appear to consume between 2 MWh and 4 MWh monthly. The sites are mixed in terms of stable consumption, growth, and little utilization.

Petroleum Displacement

The Evaluation Team estimated program-induced petroleum displacement from the 32 activated sites using three key pieces of information: electricity used for EV charging, resulting EV annual miles traveled, and equivalent annual counterfactual vehicle petroleum fuel consumption. From this information, the Team estimated the reduction in equivalent gallons of petroleum attributable to the PG&E EV Fast Charge

program. Table 99 presents estimates of petroleum displacement impacts for the EV Fast Charge program sites through 2025, including actual impacts for 2025, actual impacts for all sites in the program to date, and a 10-year forecast for all sites.

Table 99. PG&E EV Fast Charge Program Petroleum Displacement Summary

DAC	Usage (n=32)				Petroleum Displacement (GGE)		
	2025 Actual [a] (kWh)	PTD Actual [b] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
Inside DAC			8,625,912	14,893,765	213,197	376,007	1,573,337
Outside DAC			7,855,209	14,525291	199,245	376,305	1,416,099
Total			16,481,121	29,419,056	412,441	752,311	2,989,436

[a] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.
[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Highlights

- All 32 activated sites collectively achieved an impact of over 752,000 gallons of petroleum displaced in the program to date, with nearly 50% located within DACs.
- Over a 10-year period, the sites will displace more than 2.9 million gallons of petroleum.

Greenhouse Gas and Criteria Pollutant Impact

The Evaluation Team calculated reduced emissions from displaced fossil fuel use from ICE vehicles that were not in service because of the EV Fast Charge program. The Team first developed an ICE counterfactual baseline and then calculated the emissions associated with this vehicle under conditions that otherwise matched the EVs to provide a baseline. Although EVs have no tailpipe emissions, the mix of generation sources from the electric grid used includes renewable as well as fossil fuel power to supply electricity to the charging stations, with the latter primarily responsible for emitting GHGs and criteria pollutants into the atmosphere.

Table 100 presents the GHG reductions resulting from the program in 2025 and the program to date and a 10-year projection by impact location. Overall, the program achieved a 79% reduction of GHG emissions (6,188 MT total) relative to the counterfactual to date (7,486 MT, not shown in table) with just over 50% of the impact within DACs.

Table 100. PG&E EV Fast Charge Program GHG Reductions Summary [a]

DAC	Usage (n=32)				GHG Reduction (MT)		
	2025 Actual [b] (kWh)	PTD Actual [c] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
Inside DAC			8,625,912	14,893,765	1,826	3,118	14,264
Outside DAC			7,855,209	14,525,291	1,683	3,069	12,680
Total			16,481,121	29,419,056	3,509	6,187	26,944

[a] Columns may not sum to total due to rounding

[b] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.

[c] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Overall, of the local emissions, the EV Fast Charge program had the highest impact in reducing CO, resulting in an estimated annualized reduction of 122 kg (Table 101).

Table 101. PG&E EV Fast Charge Program Local Emissions Reductions

Emissions	EY2025 Sites Annualized (n=3)			PTD Sites (n=32)	
	Inside DAC	Outside DAC	Total	Actual	10-Year Projected Impact
PM_{10} (kg)	0.12	0.16	0.28	31.68	131.7
$PM_{2.5}$ (kg)	0.11	0.15	0.26	29.13	121.1
ROG (kg)	1.20	1.65	2.86	491.72	2,464.2
CO (kg)	51.38	70.62	122.00	17,316.30	87,158.6

Figure 242 shows the current mix of electricity generation sources from the CAISO grid used to support the PG&E EV Fast Charge program sites.[117] Based on the real-time grid conditions when the EVs charged, the overall energy mix contained about 51% zero-emission or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 31% natural gas. With the CAISO grid adding more renewables to meet the Renewable Portfolio Standard, GHG and criteria pollutant emissions will continue to decrease.

Figure 242. PG&E EV Fast Charge Program Net Electricity Mix, PTD Sites

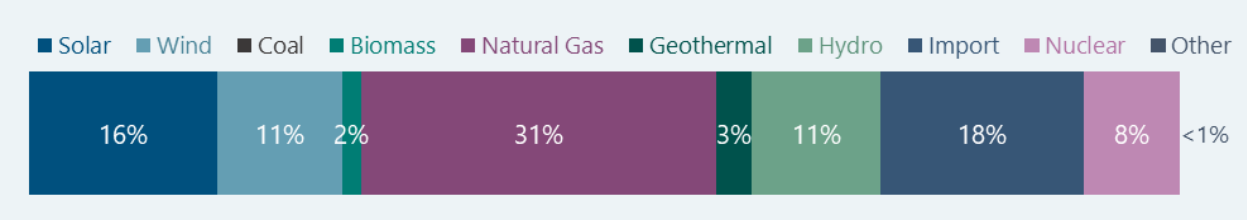
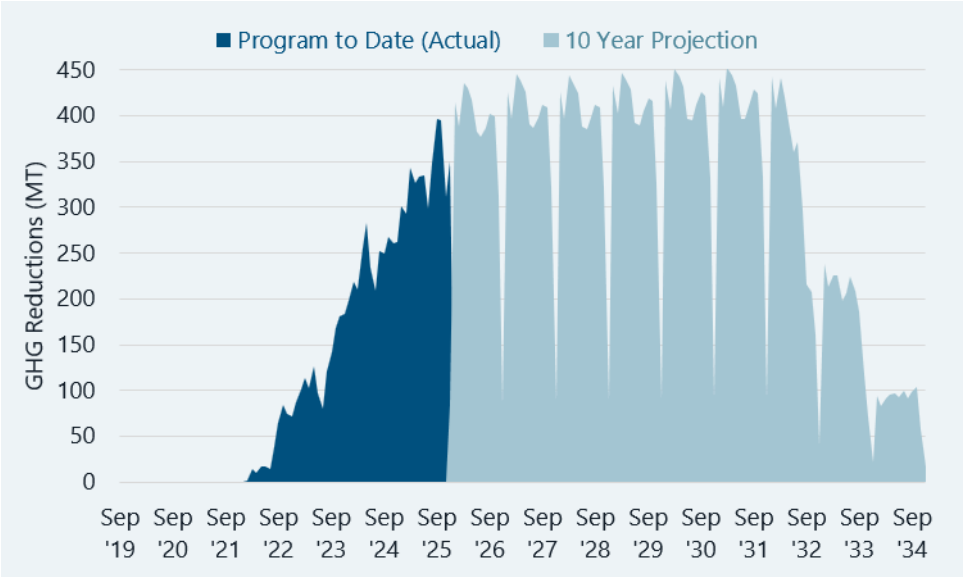


Figure 243 shows how GHG reductions have increased as a result of the EV Fast Charge program and how these reductions are expected to grow over time for all activated sites. The analysis period ranges from the date of activation for the first site in the program through the end of 2025. The analysis incorporates

[117] The power associated with imports comes from a mixture of hydro, nuclear, coal, and natural gas power plants located outside the CAISO grid.

the net reduction (counterfactual emissions minus Utility emissions) for each site within the PG&E EV Fast Charge. Emissions reductions from the program to date appear in dark blue while anticipated benefits based on annualization appear in lighter blue. Because sites began operation at different times, the 10-year sunset for each site can be observed as a gradual tapering of program benefits between 2031 and 2034. This taper reflects that benefits are no longer counted after 10 years, although the infrastructure will likely continue to be used. While each year's operations appear similar, there are several key factors driving the slight variations, such as seasonality of Utility generation sources (high Utility emissions will appear as a dip on the curves), holidays occurring on weekends versus weekdays, and extrapolation for sites that became operational late in 2025 and will operate year-round in future years.

Figure 243. PG&E EV Fast Charge Program Historical and Forecasted GHG Reductions, PTD Sites



Highlights

- The EV Fast Charge program achieved a 79% reduction of GHG to date, with over 50% of the impact occurring within DACs.
- The greatest reduction in local emissions was CO with a projected 10-year reduction of about 87,158 kg.
- Based on the real-time grid conditions when EV charging occurred, the overall energy mix contained about 51% zero-emission or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 31% natural gas.

Health Impacts

The Evaluation Team calculated public health impacts (as benefits and costs) of reductions in criteria pollutants from vehicle electrification. The pollutants included in the analysis are primary $PM_{2.5}$ and precursors of secondary $PM_{2.5}$, including NO_X, SO_2, NH_3, and VOCs. This analysis considered only tailpipe

emissions reductions rather than full lifecycle emissions (such as power plant emissions). The Evaluation Team used the EPA COBRA to evaluate the health benefits associated with the emissions reductions. COBRA estimates the county-level monetized benefits for the county where emissions are reduced. The tool also estimates monetized benefits for all counties in the United States (since emissions disperse beyond the source county), although most impacts are felt in nearby counties and the Team's analysis only examines California counties.

The morbidity-related monetary benefits the Evaluation Team estimated include avoided lost wages, avoided medical costs, and the money people are willing to pay to avoid an illness or condition such as a respiratory disease. The Team measured these benefits in terms of the value of a statistical life associated with premature mortality. COBRA reports both a low and a high impact for mortality, representing the uncertainties in the estimates.

The total value of the health benefits associated with emissions reductions from the EV Fast Charge program is between $114,971 and $160,723. Table 102 shows the cumulative health benefits in California associated with the emissions reductions realized by the electrification of PG&E EV Fast Charge sites in the program to date.

Table 102. PG&E EV Fast Charge Program California Health Benefits for PTD Sites in 2025

Health Endpoint	Change in Incidence (Annual Cases)		Monetary Value (Annual, 2025 Dollars)	
	Low	High	Low	High
Mortality	**0.007**	**0.01**	**$101,831**	**$147,583**
Avoided Medical Care				
Hospitalization, Respiratory	0.001	0.001	$12	$12
Hospitalization, Cardiovascular	< 0.000	< 0.000	$11	$11
Hospitalization, Other	0.001	0.001	$26	$26
ER Visits, Respiratory	0.014	0.014	$23	$23
ER Visits, Cardiovascular	0.001	0.001	$2	$2
Out of Hospital Heart Attacks	< 0.000	< 0.000	$3	$3
Nonfatal Heart Attacks	0.002	0.002	$159	$159
Stroke	< 0.000	< 0.000	$12	$12
Lung Cancer	< 0.000	< 0.000	$10	$10
Asthma	7.263	7.263	$5,899	$5,899
Hay Fever	0.294	0.294	$337	$337
Lost Productivity				
Minor Restricted Activity Days	2.632	2.632	$341	$341
Work Loss Days	0.448	0.448	$146	$146
School Loss Days	3.52	3.52	$6,158	$6,158
Total Health Effects	-	-	$114,971	$160,723

The Evaluation Team also examined health benefits within DACs, which may be disproportionately burdened by sources of pollution (including air pollution from ICE vehicles). Because COBRA estimates effects at only the county level, the Evaluation Team disaggregated health benefits by census tract using the relative population of each tract from the most recent ACS. For example, the Team allocated 10% of

the value of the health benefits to a census tract with 10% of the county's population. The Evaluation Team then estimated the total benefits allocated to DACs and non-DACs. This approach assumes that the benefits of emissions reductions are distributed evenly throughout the county. If the sites reside in DACs, and the emissions reductions are greater in the tracts near the sites, this approach understates the potential benefit to DACs. Additional information about emissions dispersion within counties would provide more precise estimates of health benefits to DACs and non-DACs.

In our analysis, most of the health benefits were in Alameda County which had 13% of the total benefits, followed by Contra Costa County (12%), Sacramento County (11%), Santa Clara County (9%), and San Joaquin County (7%). Overall, 17% of the health benefits are in DACs.

Highlights

- The monetary health benefits from PG&E EV Fast Charge sites range from a low estimate of $114,971 and a high estimate of $160,723.
- Most of the health benefits were in Alameda County which had 13% of the total benefits, followed by Contra Costa County (12%), Sacramento County (11%), Santa Clara County (9%), and San Joaquin County (7%).
- Overall, 17% of the health benefits are in DACs.

Utility Staff Insights

In addition to monthly check-in calls with key PG&E staff to discuss the status of the EV Fast Charge program, the Evaluation Team conducted a close-out interview with staff in March 2026 to review overall program challenges and successes in 2025.

PG&E staff reported that starting in 2021 and through 2025, a continued challenge with the program was that site construction costs were higher than anticipated and compounded by labor constraints, material costs, and supply chain delays. Being several years into implementation, PG&E staff try to address these increased costs when planning; however, they continue to strain program budgets.

- **Construction Labor and Material Costs.** Staff noted that construction labor and site material costs continued to increase in 2025 and have been more expensive than originally anticipated in 2018 (when the program funding cap was decided). PG&E staff also noted that tariffs and macroeconomic factors have strained construction costs for the program in 2025. Although staff had planned to use remaining funds in the budget to construct three additional sites, staff decided in 2025 to cancel these sites because of the increasing construction costs. The cancellation of these sites did not affect the Program's site goal, which had already been met.
- **Fire Code Changes.** In 2023, San Francisco updated its fire code, which affected two sites in the EV Fast Charge program portfolio during the 2024 and 2025 evaluation years. This change required an upgrade to overhead sprinkler systems, resulting in increased costs, additional work, and permitting requirements at both sites. Ultimately, one site host paid to upgrade the sprinkler systems and was able to finish construction in 2024, although its activation was delayed by six months. The other site was cancelled in 2025 due to increased costs.

Despite these challenges, 2025 for the EV Fast Charge program was mostly smooth, with program staff focusing on completing site construction, resolving site-specific issues, and improving program processes. The successes in 2025 centered on completing the final sites and preparing the program for sunsetting:

- **Nearing Program Completion.** Despite some site-specific challenges, in 2025 PG&E completed almost all sites for the EV Fast Charge program. At the end of 2025, Utility construction had been completed for two of the three remaining sites but these sites had not yet been activated. The final site is still in the construction phase and is expected to be completed in 2026.
- **Successful Staffing Transition.** In 2025, program manager responsibilities fully transferred to a new staff member. PG&E staff said that the transition did not impact operations or the program budget, signaling that the EV Fast Charge program is well supported despite the staffing changes.
- **Program Sunsetting.** Though the EV Fast Charge program is still not fully closed out because of the complex nature of EV infrastructure programs and length of maintenance agreements, PG&E staff are preparing for program sunsetting. In 2025, PG&E staff primarily focused on updating and correcting site data and ensuring that the data are consistent with PG&E's records. This effort gave PG&E staff an up-to-date view of the program's costs, allowing them to identify which previously paused sites the program could support. Staff ultimately decided that due to rising material costs, tariffs, and macroeconomic factors, two of these sites could not move forward.
- **Reduced Construction Costs.** In 2024, PG&E staff reported that they had stopped working with one contractor and that another contractor had raised its rates, which contributed to higher-than-anticipated construction costs. In 2025, PG&E staff reported that the program had started working with new construction contractors to ensure that the budget remains on track for the remaining sites.

Highlights

- Like in previous evaluation years, site costs continue to be a challenge, particularly the costs of construction labor and materials. In 2025, staff also noted that tariffs and macroeconomic factors have also contributed to budget strain.
- PG&E successfully managed several site-specific issues, including managing the effects of fire code changes on site design and ensuring that EVSE vendors adhere to compliance standards.
- By the end of 2025, the EV Fast Charge program was nearing completion, with two remaining sites sub-completed and just one site still undergoing construction. PG&E anticipates that the program will be completed in 2026.
- To prepare for the upcoming completion of the program, PG&E staff has begun preparing for sunsetting, which has included data cleanup and closing out site finances.

5.3.3. Lessons Learned

Upon completion of the three 2025 sites, PG&E staff successfully met the EV Fast Charge program's DAC, port, and site per se reasonableness goals. Despite some site-specific challenges, in 2025 PG&E completed almost all sites for the EV Fast Charge program. The 32 activated sites in the PG&E EV Fast Charge program achieve 100% of the program's per se reasonableness minimum goal of 30 sites and 80% of the program's maximum goal of 40 sites. There are 168 DCFC ports installed at the 32 activated sites, exceeding 100% of the program's per se reasonableness minimum goal of 156 charging ports and 84% of the program's maximum goal of 200 ports. The 39 customer contracts signed to date could satisfy 98% of the maximum site goal, and could host 204 DCFC ports, which could exceed the program's maximum DCFC port goal. In EY2025, 67% of activated sites were in a DAC, bringing the cumulative percentage of DAC sites to 56%, which exceeds the program's per se reasonableness DAC goal of 25% of sites.

Despite continued challenges, program staff have worked diligently to mitigate costs and complete sites. PG&E launched the EV Fast Charge program at the start of the COVID-19 pandemic, when severe economic disruption affected nearly every market. As a result, the program faced sustained increases in labor and material costs, supply chain disruptions. Furthermore, the program has faced permitting delays, as well as additional site requirements, including bollards, backup batteries, and fire code changes. In 2025, tariffs and other macroeconomic factors that continued to strain construction costs.

Over the last four years, PG&E staff identified several strategies to help manage these pressures. In Q4 2023, staff conducted a budget review and determined that a limited number of additional sites could still be built. In 2024, PG&E also conducted outreach to existing customers based on their prior commitments and ability to share construction costs, including requiring a $10,000 deposit before a site walk. In 2025, the program began working with new construction contractors to help keep the remaining sites on budget.

PG&E's EV Fast Charge program has a nominal but growing influence on neighborhood EV adoption. In 2025, the EV Fast Charge program increased the number of operational sites by three to bring the PTD site total to 32. The EV Fast Charge program has contributed to EV adoption of 65 EVs for households neighboring the infrastructure.

The EV Fast Charge program sites are helping to displace petroleum and reduce GHG and local emissions and achieve nominal health impacts overall and within DACs. The EV Fast Charge sites accounted for an impact of over 740,000 gallons of petroleum displaced in the program to date, with 50% of the impact within DACs. In addition, the program resulted in a 79% reduction of GHG, with nearly 50% occurring within DACs. These sites all positively contributed to lowering local emissions, with CO reduction showing the most prominent projected reductions of over 87,000 kg over a ten-year period. Overall, 17% of the health benefits are in DACs, and the total monetized health benefits range from $114,971 to $160,723.

The demand, energy consumption, and number of charging sessions is increasing in the EV Fast Charge program. Three new sites were activated in the PG&E EV Fast Charge program in EY2025, adding 1,020 kW of new installed capacity, bringing total capacity to 13,590 kW in the program to date. Overall,

energy consumption increased 52%, rising to more than 5,500 MWh in EY2025, up from 3,500 MWh in EY2024. Monthly consumption remained similar to Q4 2024 for the first half of the year at approximately 500 MWh, however it decreased by over 20% in the second half of the year, to about 400 MWh per month, driven in part by vandalism across multiple program sites. Sites vary significantly in terms of utilization, with one-third of sites dispensing at least 12 MWh in a single month, while most sites dispense 2 MWh to 4 MWh monthly. Charging session energy consumption has also grown compared with previous years. Sessions of 50 kWh or more increased from 15% in EY2024 to 17% in EY2025, and sessions of between 25 kWh and 50 kWh increased from 39% to 42% of all sessions. 50% of drivers using EV Fast Charge program sites appear to be return customers, each having five or more charging sessions in EY2025.

6. San Diego Gas & Electric Transportation Electrification Programs

6.1. Power Your Drive for Fleets

6.1.1. Overview

This overview provides a detailed description of the San Diego Gas & Electric (SDG&E) Power Your Drive for Fleets (PYDFF) program; summaries of the program implementation process, performance metrics, materials, and budget; and a timeline of major milestones. Following the overview are findings, highlights, and lessons learned.

Program Description

Per Decision 19-08-026, SDG&E's PYDFF program provides infrastructure for fleet electrification at a low cost or at no cost to participants who purchase or lease at least two medium- or heavy-duty (MDHD) EVs to augment or replace vehicles in their fleet. SDG&E launched the PYDFF program in September 2020 to accelerate the adoption of MDHD EVs by providing infrastructure for fleet electrification and working with fleets from initial planning and design to construction and ongoing site maintenance phases. PYDFF has an approved budget of $107.4 million and was designed to enroll and assist a minimum of 300 sites supporting the electrification of 3,000 MDHD on-road and off-road vehicles.

PYDFF Program Target

Achieve a minimum of 300 sites with 3,000 MDHD EVs supported.

Customers participating in the PYDFF program can choose either Utility ownership or customer ownership of BTM infrastructure. With Utility ownership, SDG&E will pay for, construct, own, and maintain all infrastructure up to the EVSE. The customer will then pay for, construct, own, and maintain the EVSE. If the customer decides to own the BTM infrastructure, then SDG&E will pay for, construct, own, and maintain all TTM infrastructure, and the customer will pay for, construct, own, and maintain all BTM infrastructure and receive an incentive payment for up to 80% of the resulting costs. Additional charger rebates of up to 50% of the cost of the chargers are available for transit agencies, school districts, and fleets located in DACs that are not operated by Fortune 1000 companies.

To participate in the PYDFF program, fleets must meet specific criteria. The program requires participating customers to obtain at least two MDHD EVs, which are defined as Class 2 through Class 8 on-road and off-road vehicles, including MDHD trucks and vans, transit buses, commuter buses, school buses, TRUs, airport GSE, port equipment, forklifts, and other equipment. Fleets must also own or lease the property where the infrastructure will be installed, operate and maintain the infrastructure for 10 years, provide data related to EV usage, use approved vendors for the EVSE, and use qualified/state-licensed labor for all work,

PYDFF Program Design Goal

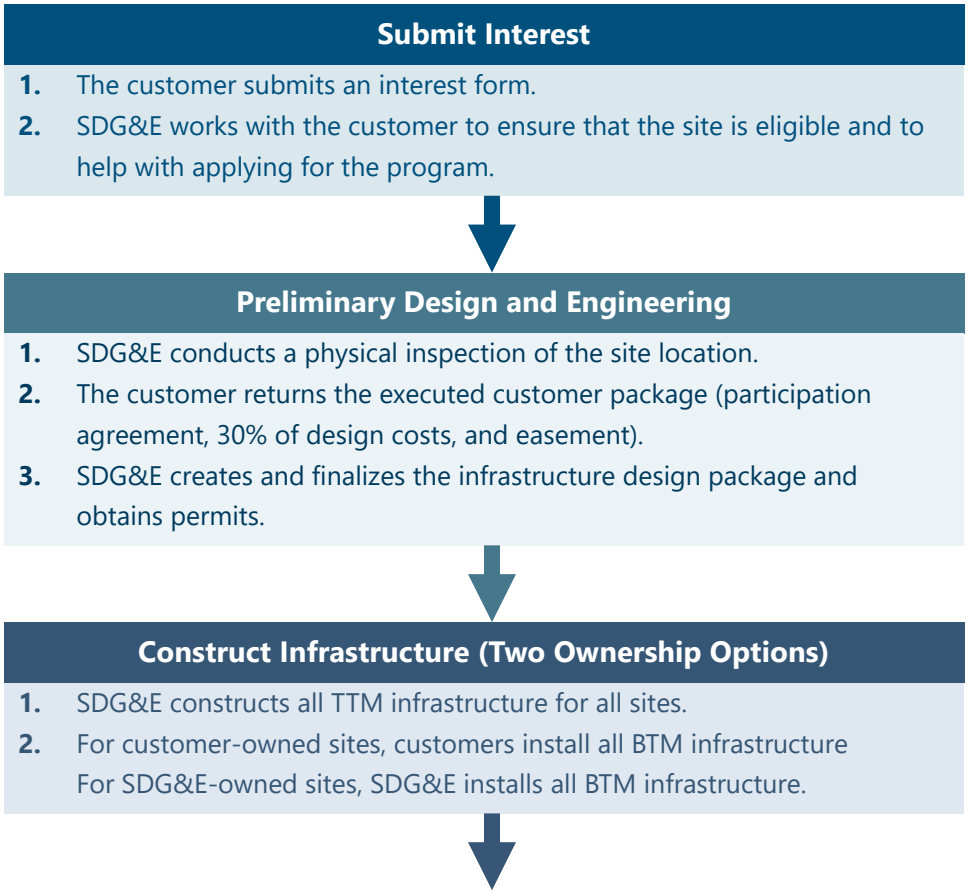
Accelerate the adoption of MDHD EVs by providing infrastructure for electrification while working with fleet operators from the initial planning phases to design, construction, and ongoing site maintenance.

among other requirements. Specific terms and conditions listed in Appendix B and section 6.4 of Decision 19-08-026 require that a minimum of 30% of the infrastructure budget for PYDFF be allocated to deploy infrastructure in DACs. As allowed by the Decision, SDG&E submitted an Advice Letter in September 2023 requesting to change the DAC definition to use the CalEnviroScreen service territory definition. The CPUC initially denied this Advice Letter but approved the refiled request in August 2024. The Decision also states that at least 10% of infrastructure expenditures must support deployment of transit buses and school buses and that no more than 10% can support deployment of electric forklifts.

Implementation

Figure 244 shows the key steps in the PYDFF program implementation process. There were no major changes to the implementation process in 2025.

Figure 244. SDG&E PYDFF Program Implementation Process



Activate Site

1. SDG&E inspects and energizes equipment.
2. The customer commissions EV charging stations.

Close-Out and Maintenance

1. SDG&E conducts a post-event job walk.
2. The customer is responsible for charger and ongoing maintenance of other customer-owned infrastructure; SDG&E is responsible for ongoing maintenance of infrastructure that SDG&E owns.

Program Performance Metrics

The Evaluation Team reviewed the sites participating in the PYDFF program and organized them by program status. Table 103 shows the number of sites in the program by completion status as of December 31, 2025.

Table 103. SDG&E PYDFF Program Total Site Count by Status

Site Status	EY2025	Program to Date
Utility Construction Complete	15	41
Activated [a]	12	37
Operational	12	37
Closed Out	5	28

[a] The Evaluation Team considers a site as activated in a given evaluation year only if the site has completed the final program phase or has electricity usage in that year. The activated status includes both currently active and decommissioned sites that were activated in the program.

In EY2025, the SDG&E PYDFF program received 15 applications, signed contracts with 16 sites and activated 12 sites that supported 237 MDHD vehicles. This increased the total number of applications received to date by the SDG&E PYDFF program to 151 and the total number of contracts executed to date to 62.[118] As shown in Table 104, 33% (4 of 12) of the MDHD activated sites in EY2025, and 40% (15 of 37) of sites activated in the program to date are located within a DAC.

[118] The number of applications received to date by the SDG&E PYDFF program includes sites that have been put on hold or cancelled.

Table 104. SDG&E PYDFF Program Activated Sites by Market Sector in EY2025 and Program to Date

Market Sector	EY2025		Program to Date	
	Sites in DAC	Sites in Non-DAC	Sites in DAC	Sites in Non-DAC
Airport GSE	-	-	-	1
Heavy-Duty Vehicle	-	1	-	2
Medium-Duty Vehicle	3	5	9	9
School Bus	1	2	4	9
Transit Bus	-	-	1	1
Truck Stop Electrification	-	-	1	-
Total	4	8	15	22

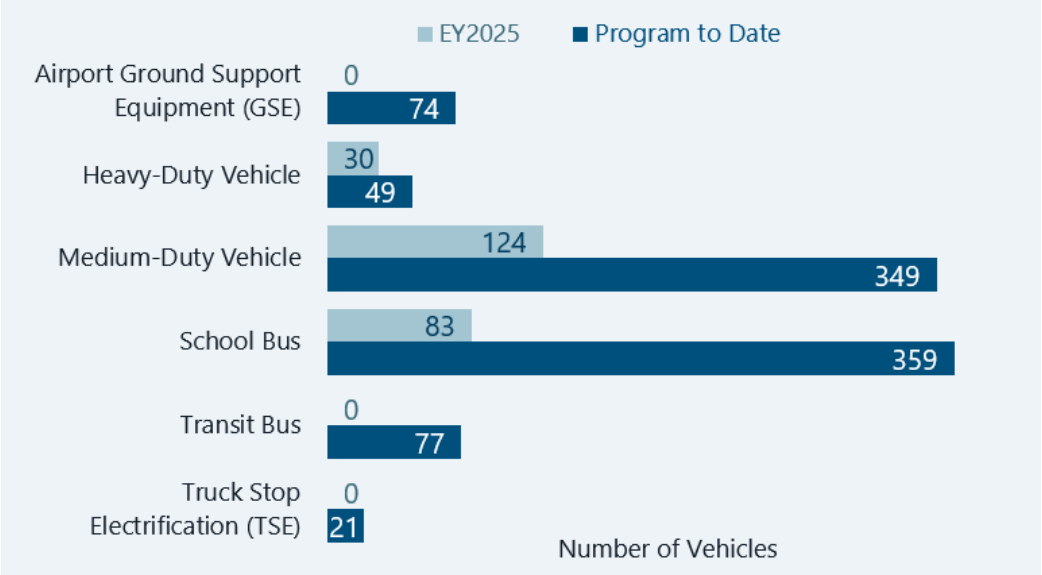
In EY2025, eight of the 12 activated sites in the SDG&E PYDFF program were in the medium-duty vehicle market sector, three sites were in the school bus market sector, and one site was in the heavy-duty vehicle market sector. There were no new activated sites in the airport GSE, transit bus, or truck stop electrification market sectors.

Medium-duty vehicle and school bus sites remain the largest percentage of activated sites in the SDG&E PYDFF program to date, with 49% and 35% of activated sites, respectively. The heavy-duty vehicle and transit bus market sectors each have two activated sites, or 8% of activated sites in the PYDFF program to date, while the airport GSE and truck stop electrification market sectors each have a single site and represent less than 3% of all activated sites in the program to date.

In EY2025, SDG&E installed infrastructure to support 237 MDHD vehicles in the medium-duty vehicle (124), school bus (83), and heavy-duty vehicle (30) market sectors based on 10-year VAPs submitted by customers at the time they signed their program participation agreement. This brings the total number of MDHD vehicles electrified in the PYDFF program to date to 929.[119] Figure 245 shows the breakdown of the MDHD electrified vehicles by market sector for EY2025 and PTD sites.

[119] MDHD vehicles electrified to date in the PYDFF program do not align with past evaluation year reporting because some sites activated in past evaluation years have updated their 10-year VAPs with additional MDHD EVs.

Figure 245. SDG&E PYDFF Program Vehicles Supported by Market Sector



By the end of EY2025, the PYDFF program had activated 37 sites which support electrification of 929 MDHD vehicles (per customers' VAPs). As shown in Figure 246, 62 contracts have been signed in the program to date, which satisfies 21% of the program's per se reasonableness goal of 300 sites. These sites would support 1,451 MDHD vehicles, which would meet 48% of the program's per se reasonableness goal of 3,000 vehicles. Notably, the ratio of vehicles per site based on the per se reasonableness goals in the CPUC Decision is 10 MDHD EVs per site (3,000 divided by 300). The ratio in the program to date is 24 MDHD EVs per site, which is more than twice the ratio in the CPUC decision.

Figure 246. SDG&E PYDFF Program Per Se Reasonableness Site and Vehicle Goal Progress

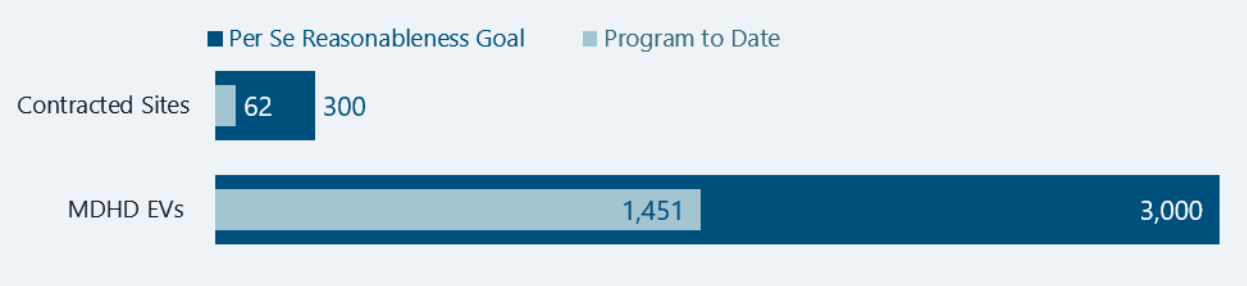


Table 105 displays the median durations per program phase (measured in calendar days) for EY2025 and PTD activated sites, which provides insight into program phase length trends over time.[120] Sites did not necessarily pass through each phase in the same calendar year. For example, EY2025 activated sites may have passed through design and permitting in 2024 while others passed through in 2025. Generally,

[120] For EY2025, SDG&E updated its method for mapping its internal application milestones to CPUC Program Phases. As a result, EY2025 and program-to-date median durations for the SDG&E PYDFF program cannot be directly compared with durations included in previous evaluation reports.

application review and activation have the shortest median durations, while contract issuance, design and permitting, and construction have the longest.

Table 105. SDG&E PYDFF Program Median Calendar Days per Phase for EY2025 and PTD Sites

CPUC Program Phase	Median Calendar Days	
	EY2025 [a]	Program to Date [b]
Application Review	11	3
Site Assessment	38	28
Contract Issuance	441	118
Design and Permitting	292	270
Construction Complete	220	190
Activation	5	5

[a] "EY2025" represents the data for the sites activated in 2025.

[b] "Program to Date" represents the data from all activated sites from program inception for all program years.

Figure 247 expands the analysis of program phase duration for EY2025 by displaying the average number of calendar days per phase (denoted by X), calendar day median (middle line inside of box), the first quartile (bottom of box), third quartile (top of box), minimum (bottom tail), maximum (top tail), and outliers (dots). The distributions per program phase provide deeper insight into program phase completion, showing that the contract issuance, design and permitting, and construction phases generally took the most calendar days to complete. Application review and activation were the shortest program phases and had the least variation in completion times in EY2025.

Figure 247. SDG&E PYDFF Program Calendar Days per Phase for EY2025 Sites

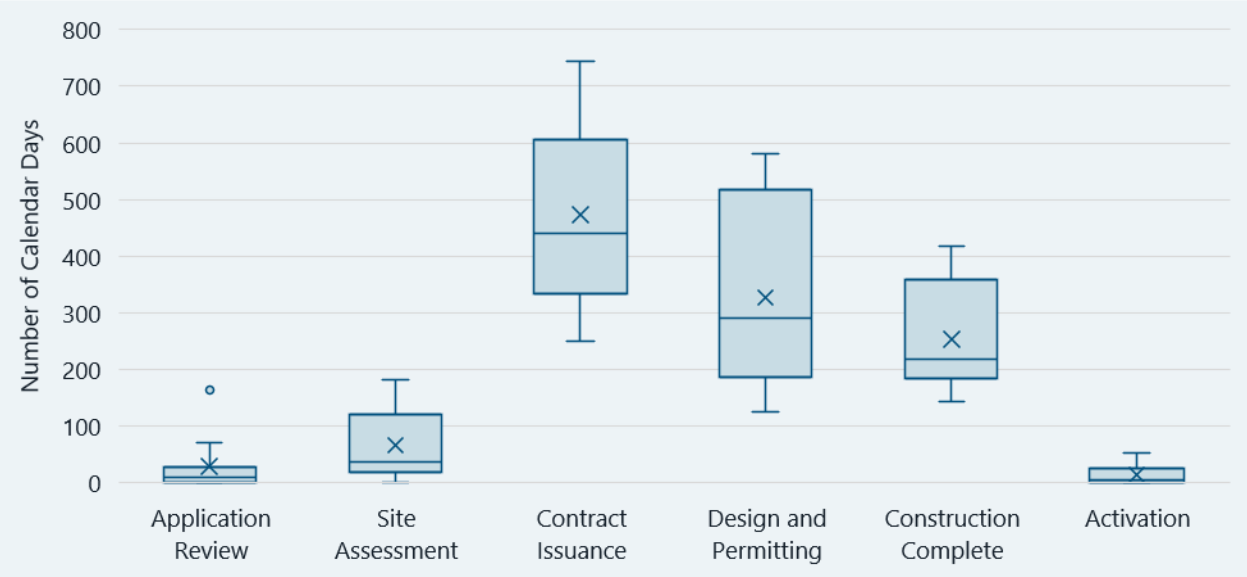


Table 106 displays the median number of calendar days that PYDFF program sites spent from program start to finish (application review to activation) for both the 12 activated sites in EY2025 and the 37 activated sites to date. The 12 activated sites in EY2025 had a median start-to-activation duration of 1,137

calendar days, while the 37 activated sites in the program to date had an overall median start-to-finish duration of 871 calendar days, ranging from 585 calendar days for school bus sites to 1,980 days for the airport GSE site.

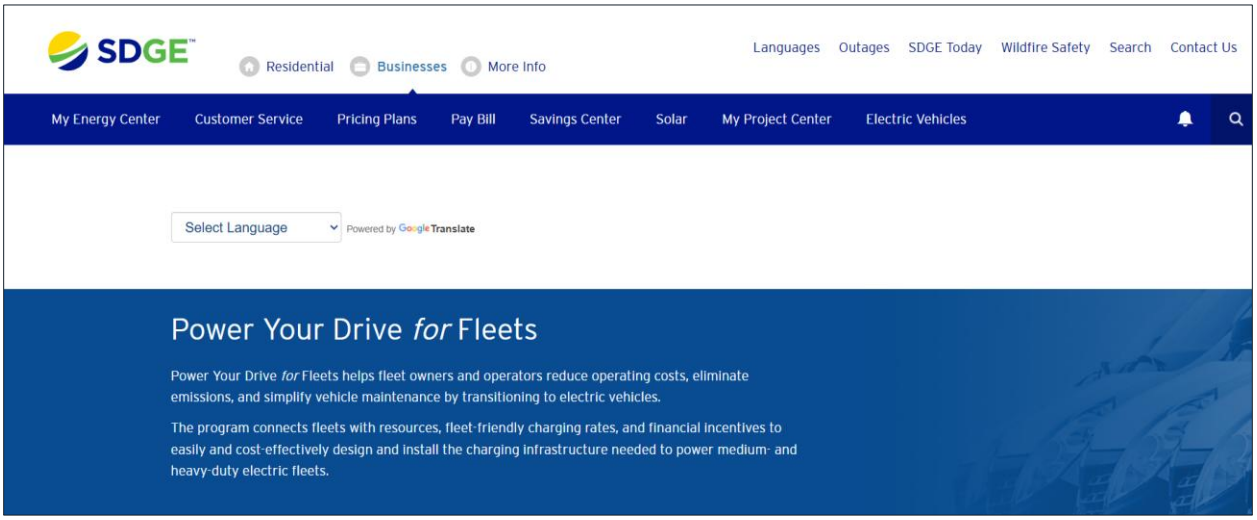
Table 106. SDG&E PYDFF Program Median Duration for Site Activation by Market Sector, EY2025 and PTD Sites

Market Sector	EY2025		Program to Date	
	Median Duration Start-to-Finish (Calendar Days)	Number of Activated Sites	Median Duration Start-to-Finish (Calendar Days)	Number of Activated Sites
Airport GSE	-	-	1,980	1
Heavy-Duty Vehicle	1,118	1	948	2
Medium-Duty Vehicle	1,147	8	1,033	18
School Bus	1,255	3	585	13
Transit Bus	-	-	1,066	2
Truck Stop Electrification	-	-	776	1
All Market Sectors	1,137	12	871	37

Program Materials Summary

Throughout 2025, SDG&E staff continued program promotion, attracting 2,029 website visitors to and 3,811 page views of the SDG&E website over the course of the year (Figure 248).

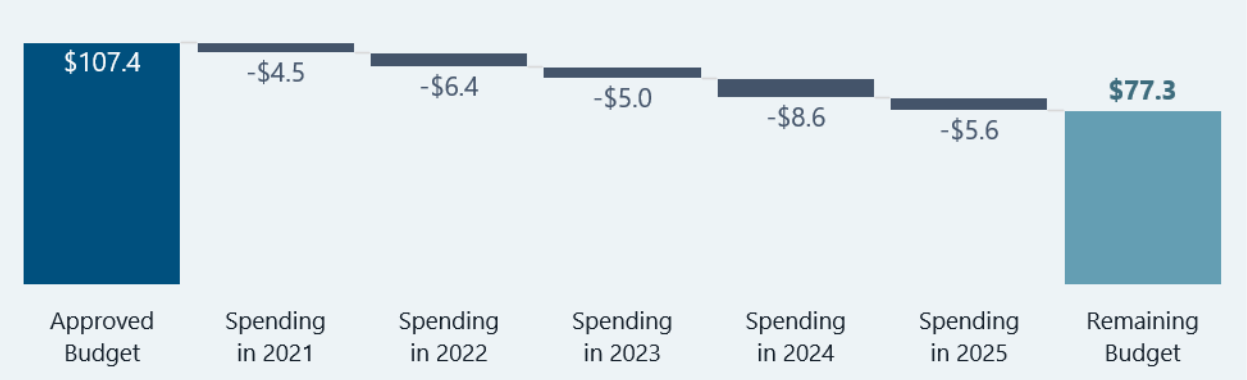
Figure 248. SDG&E PYDFF Program Website Homepage



Budget Summary

As shown in Figure 249, from program inception through December 31, 2025, SDG&E spent $30.1 million of the approved $107.4 million (constant dollars). In EY2025, program spending was $5.6 million. Figure 249 does not include spending on sites that were not fully closed out as of December 31, 2025.

Figure 249. SDG&E PYDFF Program Spend



Timeline

Since the beginning of the PYDFF program SDG&E staff have filed several Advice Letters.

On September 30, 2019, SDG&E filed AL 3437-E to request CPUC approval for establishing balancing accounts for the MDHD Program and V2G Pilot and to outline its cost recovery approach.

In August 2020, SDG&E filed AL 3587-E, its first cost tracking update, and AL 3588-E, a status update ahead of the Q3 2020 program launch. At that point, SDG&E staff had engaged 28 interested customers, including six beta sites with 63 EVs and 43 charging ports. SDG&E finalized rebate structures and introduced the new EV-High Power (EV-HP) rate. Staff also identified early participation barriers, including the required 10-year customer commitment and COVID-19-related budget constraints.

In August 2021, SDG&E filed AL 3825-E with its second cost tracking update and AL 3829-E to provide a broader program status update. By July 2021, SDG&E had engaged 155 customers, with 24 in early design and one with an operational site. In August 2022, SDG&E submitted AL 4056-E, its third cost tracking update, which documented actual expenditures and compared them with the approved budget.

In 2024, SDG&E received approval for the resubmitted AL 4436-E originally filed on September 30, 2022. This Advice Letter requested an expansion of the definition of DACs in the service territory application to match the definition approved in AL 2876-E.[121] Approved in March 2016, AL 2876-E outlined SDG&E's initial DAC definition for the EV VGI Pilot Program. This earlier definition had served as the basis for the expanded approach in AL 4086-E. The CPUC initially rejected AL 4086-E, indicating that SDG&E did not

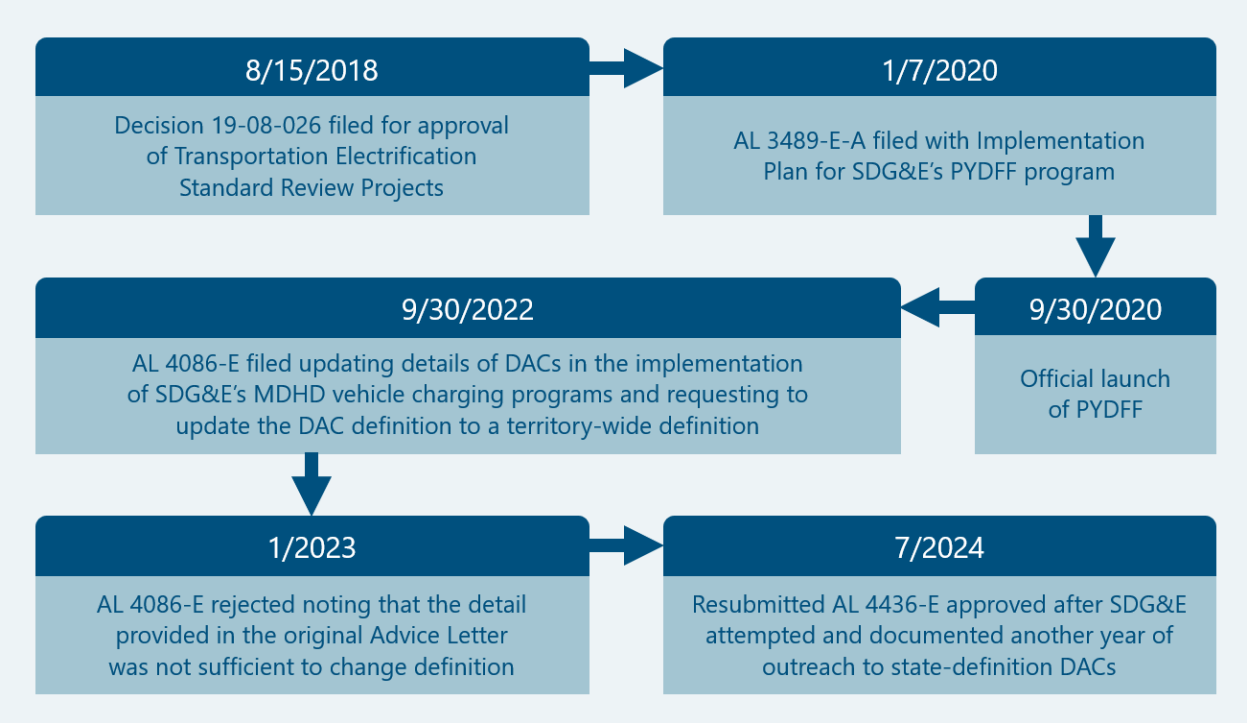
[121] SDG&E submitted AL 2876-E for the EV-Grid Integration (VGI) Pilot Program to allow SDG&E to define DACs using the CalEnviroScreen service territory definition rather than the CalEnviroScreen state DAC definition.

have enough evidence of its outreach to state-defined DACs. As a result, in 2023 and 2024 SDG&E continued to prioritize outreach to state-defined DACs and increased the rigor of documentation for this outreach. As the additional outreach did not garner additional participation, SDG&E resubmitted the request in May 2024 via AL 4436-E with updated information on its state DAC outreach efforts, and the CPUC approved this Advice Letter in July 2024.

Although it did not file a formal Advice Letter, SDG&E submitted a request in 2024 through Rule 16.6[122] to extend program enrollment through December 2026, which the CPUC approved in 2025. In August 2025, SDG&E filed AL 4706-E as part of its ongoing annual cost tracking requirements. No Advice Letter was filed in 2025 to modify the program, and staff developed targets in preparation for submitting a formal request for an extension to the program in 2026.

Figure 250 shows all major milestones since the beginning of the program.

Figure 250. SDG&E PYDFF Program Key Milestones



[122] Rule 16.6 provides an extension to comply with commission decision or order. See www.law.cornell.edu/regulations/california/20-CCR-16.6 for further information.

6.1.2. Findings

The following sections provide findings from the Utility staff interviews, as well as from surveys, site visits, and deep dive sites. The Evaluation Team also provides insights from the co-benefits and co-cost analysis, site costs, grid impacts, petroleum displacement, GHG and criteria pollutant reductions, health, and net impacts.

Table 107 summarizes key impact parameters for EY2025 and the program to date and provides estimates of impacts for goals as part of the impact evaluation. The table also provides estimates of impacts across all sites included in the program population through the end of 2025.

Table 107. SDG&E PYDFF Program Impacts Summary

Impact Parameter	EY2025 Sites [a]	EY2025 Sites Percentage in DAC	PTD Sites Actual	PTD Sites Actual Percentage in DAC
Population of Activated Sites	12	33%	37	41%
Sites Included in Analysis	12	33%	37	41%
Ports Installed in Analyzed Sites	175	26%	478	31%
EVs Supported [b]	237	30%	929	39%
Electric Energy Consumption (MWh)		3%		44%
Petroleum Displacement (DGE)	85,722	3%	1,024,262	39%
GHG Emission Reduction (MT) [c]	770	3%	8,840	35%
NO_X Reduction (kg)	364	0%	7,162	10%
PM_{10} Reduction (kg)	2.0	4%	359	1%
$PM_{2.5}$ Reduction (kg)	1.9	4%	331	1%
ROG Reduction (kg)	10.7	10%	524	16%
CO Reduction (kg)	327	12%	82,577	67%

[a] Energy consumption, petroleum displacement, and emissions reductions are based on annualized data for sites activated in 2025. Program-to-date results are based on actual data (see *Appendix B* for details).

[b] The Evaluation Team derived the EVs supported value from applicants' VAPs. This value represents the maximum number of vehicles expected to be supported by the charging infrastructure.

[c] GHGs include CO_2, CH_4, and N_2O multiplied by their respective GWP as defined by IPCC AR5 (see *Appendix B* for details).

[d] Two sites share energy meters with previously activated sites (phase 2 projects at the same location).

Utility Staff Insights

In addition to monthly check-in calls with key SDG&E staff to discuss the status of the PYDFF program, the Evaluation Team also conducted a close-out interview with staff in February 2026 to review overall challenges and successes in 2025. The following bullets summarize specific challenges experienced in 2025 by customers and SDG&E staff:

- **Federal Regulatory Uncertainties.** In 2025, staff reflected that federal regulatory changes noted below contributed to increased customer wariness about projects and a general lack of clarity around the regulatory environment. This trend, and SDG&E staff's increased need to help customers navigate the regulatory complexity, is a continuation of challenges from previous years.
- **ACF Waiver Withdrawal.** In January 2025, CARB withdrew its request for a Clean Air Act waiver for California's ACF regulation in the face of federal government opposition. The withdrawal led to less engagement from private sector customers who were no longer beholden to electrify their

fleets by regulation. As a result, program staff noted that public customers such as transit agencies who still must comply with state regulations have become more prominent participants in the program.

- **Federal Tariff Confusion.** Staff reported that new tariffs on international trade in 2025 have caused uncertainty among customers, particularly in the US-Mexico border region. The unpredictability has precipitated a drop in program interest, with some customers reducing their engagement with the program.
- **Supply Chain Lead Times.** The supply chain has continued to be a challenge, with many customers struggling with long lead times for equipment like switchgears, which SDG&E staff estimate at between 14 and 18 months. This is consistent with wait times of up to 15 months reported in 2024.
- **Vendor Customer Service Issues.** Staff reported that not all vendors provide sufficient customer service for the delivery, commissioning, and maintenance of EVSE. Staff turnover at vendor companies has caused additional difficulty, breaking chains of communication and slowing coordination. Such challenges with vendors can increase customer hesitation to making the transition to EVs, and SDG&E staff are limited in their capacity to recommend vendors.

Over 2025, SDG&E staff continued to make improvements to the program to address challenges and ensure continued site success:

- **Accelerated Participation Requirements.** Staff reported that under the PYDFF program's previous structure, customers were not formally considered participants and did not have to officially commit to the site until SDG&E issued a customer job package. Many customers chose to pause or discontinue progress until SDG&E had released their customer job package, which included design plans, program terms and conditions, and easement documentation when applicable. In 2025, SDG&E staff began requiring customers who paused their projects for extended periods to sign a participation agreement up front before the Utility would deploy additional design and engineering resources. According to SDG&E staff, this change allows the Utility to better safeguard ratepayer-funded costs by ensuring resources were not deployed for sites where customers had not yet committed to the program.
- **Peer-Led Engagement.** Building on an approach established in previous program years, SDG&E staff continued to lean on the relationships they have established with customers through successful site installations to help educate and guide prospective and current PYDFF participants. These relationships have been especially vital for public sector projects, with SDG&E staff collaborating with previous PYDFF program participants to share their experience in public forums. Similarly, the Utility has continued to pair potential participants with past program participants who provide firsthand guidance about the program based on real program experience.
- **Customer Outreach**. In 2025, SDG&E staff's sustained outreach approach strengthened relationships with customers. According to staff, as a result of SDG&E continuing to engage customers directly and proactively help them navigate policy shifts, customers have come to view the Utility's guidance as more personalized and aligned with their interests and needs. This

improved trust has improved engagement with and support of larger customers throughout the program process.

- **Infrastructural Response to Industrial Growth.** In response to industrial growth in the Otay Mesa area, SDG&E staff established an internal cross-functional team to monitor the growth, proactively allocate engineering resources, and support infrastructure development to serve emerging customer demand. Customers in this area have shown less interest in the PYDFF program in the absence of regulatory requirements; however, SDG&E has continued making structural improvements to ensure that electrification is a practical option for those who are motivated to electrify without regulatory requirements and those who choose to electrify if the regulatory environment shifts back to private-sector electrification.

Highlights

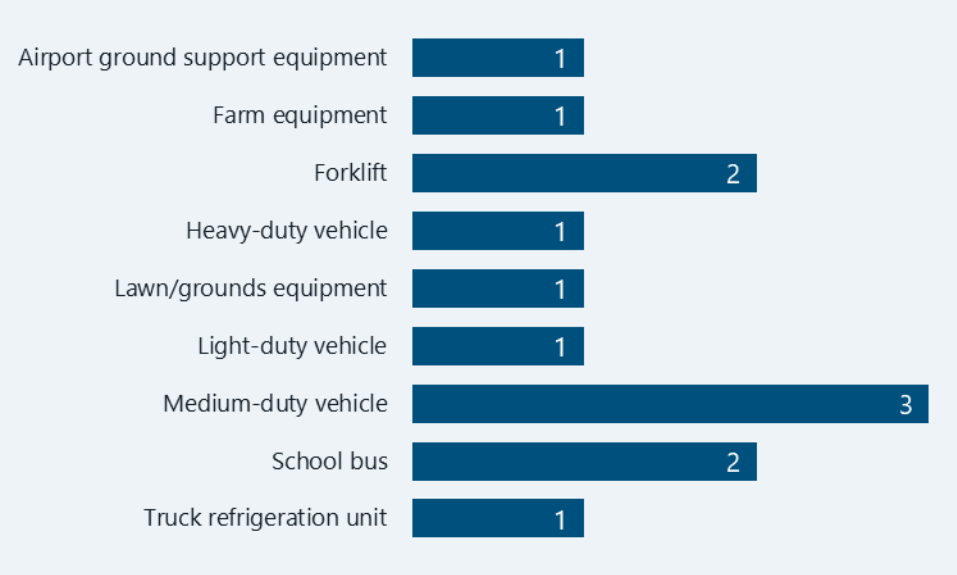
- Regulatory changes at the federal level, including the withdrawal of the ACF waiver, led to a drop in private-sector program participation and reduced interest from border area projects, while public-sector customers still affected by state regulations remained active in the program.
- Inconsistent EVSE vendor support for delivery, commission, and maintenance contributed to customer uncertainty, with SDG&E having limited ability to guide vendor selection.
- SDG&E staff accelerated participation requirements to ensure site commitment, expanded peer-to-peer engagement, deepened customer outreach, and created an internal team to address industrial growth to help improve project follow-through and support infrastructure readiness.

Survey Results

The Evaluation Team asked participating fleet managers about their motivations and barriers to electrification, satisfaction with and awareness of the program, experience with EVs and charging infrastructure, and perspective on the industry. The Evaluation Team received one complete survey response and two partial responses.

Figure 251 shows the number of each vehicle type among respondents' fleets. Medium-duty vehicles were the most common among respondents, with all three respondents reporting them as part of their fleet.

Figure 251. SDG&E PYDFF Program Fleet Manager Vehicle Types in Fleets

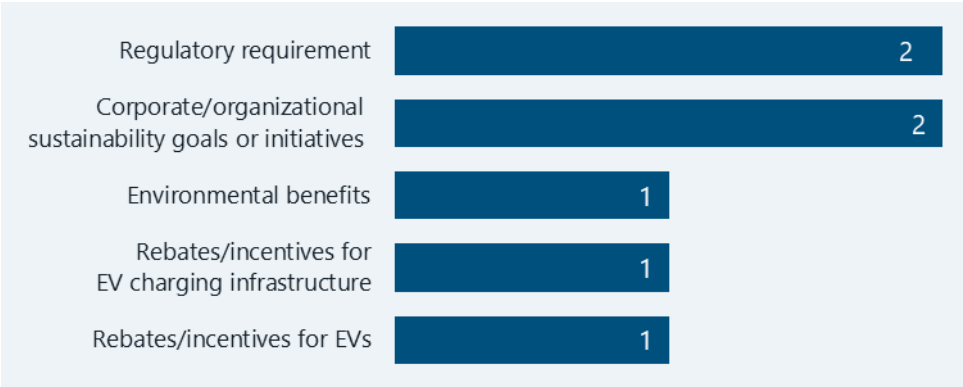


Source: Fleet Manager Survey (n=3)

Electrification Motivators and Barriers

The Evaluation Team asked the three fleet managers about their motivations for transitioning from ICE vehicles to EVs. As shown in Figure 252, the top motivators were regulatory requirements and corporate/organizational sustainability goals or initiatives, cited by two fleet managers. Environmental benefits, rebates/incentives for EV charging infrastructure, and rebates/incentives for EVs were each cited by one fleet manager. This is similar to EY2023, when two fleet managers also identified corporate/organizational sustainability goals or initiatives as a top motivator. Rebates/incentives for EVs were also top motivators in EY2023 and EY2022 for two of two and seven of seven respondents, respectively. The Evaluation Team did not receive survey responses from fleet managers in the PYDFF program in EY2021 or EY2024.

Figure 252. SDG&E PYDFF Program
Fleet Manager Motivators for Transitioning to EVs in EY2025



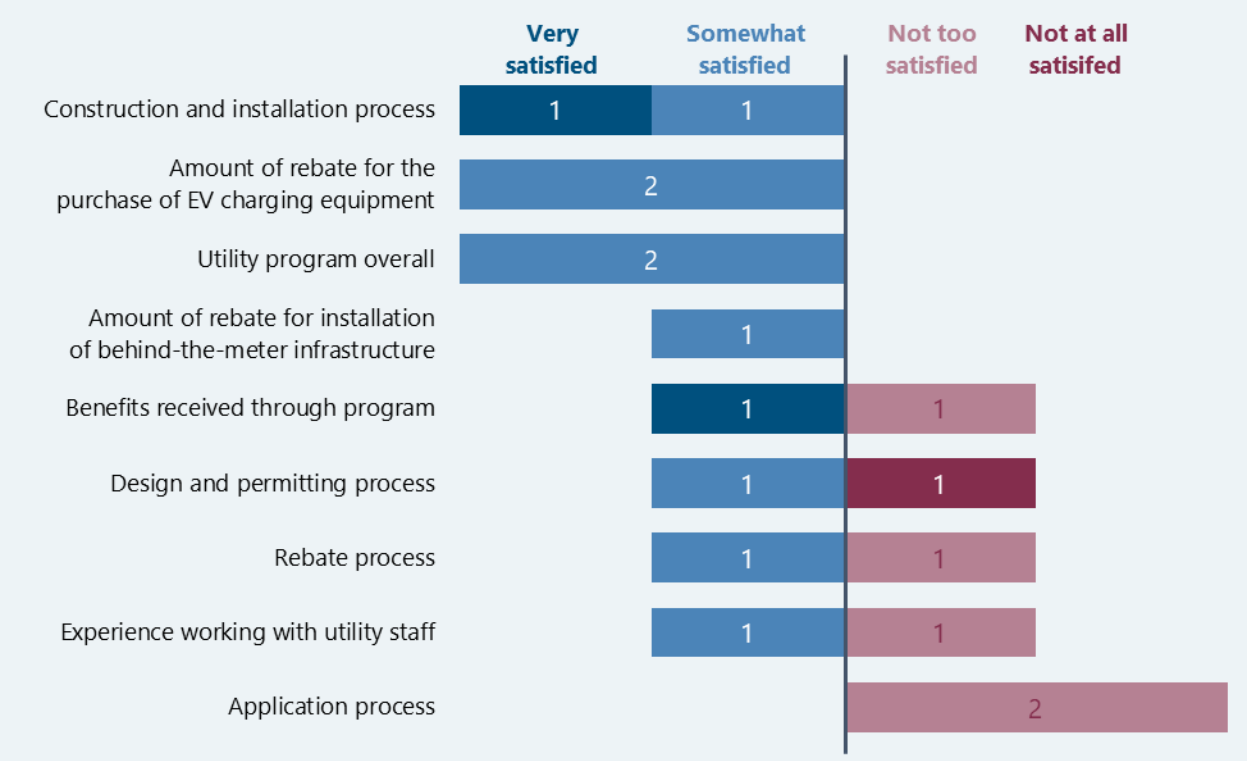
Source: Fleet Manager Survey Question C1. "Why did your fleet decide to transition to EVs? Select all that apply." (n=2)

The Evaluation Team asked fleet managers which barriers to electrification their fleets faced before program participation and which barriers remained after participation. One fleet manager said their barriers prior to participation were the prohibitive cost of EVs and the cost of EV charging equipment. After program participation, the fleet manager reported that the cost of EVs remained a barrier to electrification. The cost of installing EV charging equipment was also a top barrier to participation in EY2022, cited by five of seven fleet managers before participation, but only one after participation.

Program Satisfaction

The Evaluation Team asked fleet managers to rate their satisfaction with SDG&E's PYDFF program and its various elements. Across program elements, two fleet managers reported satisfaction and dissatisfaction, with both *somewhat satisfied* with the program overall (Figure 253). Fleet managers were most satisfied with the construction and installation process, with one rating themselves as *very satisfied* and the other as *somewhat satisfied*. Both fleet managers were *somewhat satisfied* with the amount of rebate for the purchase of EV charging equipment, but they were *somewhat dissatisfied* with the application process. Program satisfaction was high across elements in previous program years, including EY2023, when two fleet managers were *very satisfied* or *somewhat satisfied* with all program elements, and in EY2022, when only one of six fleet managers was *not too satisfied* or *not at all satisfied* with several program elements.

Figure 253. SDG&E PYDFF Program Satisfaction with Program Elements in EY2025



Source: Fleet Manager Survey Question B1. "Thinking about your experience with the PYDFF program, how satisfied are you with the following?" (n=2)

The Evaluation Team also asked fleet managers to describe aspects of the PYDFF program with which they were particularly satisfied or dissatisfied. One fleet manager emphasized that their costs were very low due to program participation, which "made installing this scale of EV infrastructure feasible." In contrast, two fleet managers said the length of time it took to participate was the greatest source of dissatisfaction.

Program Awareness

The Evaluation Team asked fleet managers how they learned about the PYDFF program. Two fleet managers said they learned about it directly from SDG&E staff. In EY2023, one of two fleet managers learned about the program from SDG&E, and in EY2022, four of five fleet managers learned about the program from SDG&E.

Experience with EVs and Charging Infrastructure

When asked to rate the ease of using their EVSE, one fleet manager said the charging equipment was *very easy* to use. The same fleet manager reported that their EVs and charging equipment were both *very reliable*. In contrast, in EY2023 and EY2022, fleet managers reported that their EVs and EV charging equipment were either *somewhat reliable* or *not too reliable*.

Experience with Load Management and EV Charging

When asked whether they were aware that SDG&E charges different electric rates per kilowatt-hour depending on the time of day—and whether they were aware of the cost to their company or organization to charge their fleet—one fleet manager said that they were aware, while the remaining two fleet managers did not provide a response.

The Evaluation Team asked fleet managers whether they took any actions to ensure that they purchased the lowest-cost electricity for charging their fleet, or, in other words, if they participated in load management. One fleet manager said they trained drivers or other staff to plug in their vehicles during off-peak times and used load management software included with their EVs or EV charging equipment, explaining that they practiced load management to lower charging costs.

Impact of Program on Fleet Electrification

The Evaluation Team asked fleet managers whether they planned to accelerate procurement of EVs and related equipment based on their experience with the program. One of the three fleet managers reported that they did not plan to change their procurement. In previous years, most fleet managers also said they would not have made any changes to their procurement, with two of two in EY2023 and three of seven in EY2022. The Evaluation Team also asked fleet managers what they would have done regarding electrification if the PYDFF program had not been available. One fleet manager said that they would have proceeded with a 75% smaller, similar transportation electrification project.

Industry Perspective

The Evaluation Team asked how well positioned fleet managers thought their industry or sector was for electrification. One of the three fleet managers said that their industry was somewhat well positioned. The Evaluation Team also asked fleet managers which type of truck—electric or diesel—they consider to be riskier, given their understanding of requirements for fleets to purchase zero-emission MDHD trucks over

the next three years and 10 years. One respondent said that electric trucks would be the riskier choice for the three-year projection and diesel trucks for the 10-year projection.

Highlights

- Fleet managers were motivated to participate primarily because of regulatory requirements (two fleet managers) and corporate/organizational sustainability goals or initiatives (two fleet managers).
- Top barriers to fleet electrification before program participation were the cost of EVs (one fleet manager) and the cost of installing EV charging infrastructure (one fleet manager). After program participation, the cost of installing EV infrastructure was no longer a barrier for the fleet manager.
- Two fleet managers rated themselves as *somewhat satisfied* with their experience participating in the EV Fleet program.
- One fleet manager said that their EV charging equipment and EVs were *very reliable*.
- One fleet manager reported practicing load management with their fleets.
- One fleet manager did not plan to change their EV and EV charging equipment procurement due to their experience with the program.
- One fleet manager reported that their industry or sector was somewhat well positioned for electrification.

Site Visit Findings

In 2025, the Evaluation Team completed 15 site visits in the SDG&E territory across three market sectors including three sites that were not activated in 2025 (no charging usage) but utility completed construction and chargers were installed: heavy-duty vehicle (2), school bus (3), and medium-duty vehicle (10, representing multiple vehicle types and uses). During the site visits, the Team collected qualitative and quantitative information that provided an understanding of fleet composition and operations. The Evaluation Team used site visits to verify information such as the number of installed chargers, the EVSP the fleet uses, types of EVs in use or scheduled for delivery, and physical influences on construction designs.

Table 108 shows charging site characteristics by market sector, including number of site locations visited, number of L2 and DCFC ports, and total charging capacity. In total, the EY2025 activated sites in the SDG&E PYDFF program added 66 L2 ports and 109 DCFC ports with more than 6 MW of EV charging capacity. This brings the total charging capacity of PTD sites to more than 15 MW. Figure 254 is a visual representation of Table 108 showing charging ports and capacity of PYDFF program site visit locations by market sector for EY2025 and PTD sites.

Table 108. SDG&E PYDFF Program Quantity of Ports by Type and Installed Capacity by Market Sector, EY2025 and PTD Sites

Market Sector	EY2025 Sites Visited	EY2025 Sites Ports	EY2025 Sites Capacity (kW)	PTD Sites Visited	PTD Sites Ports	PTD Sites Capacity (kW)
Airport GSE	0	0	0	1	78	840
Heavy-Duty Vehicle	1	18	1,620	2	20	1,745
Medium-Duty Vehicle	8	84	1,829	18	159	3,635
School Bus	3	73	2,690	13	185	6,117
Transit Bus	0	0	0	2	32	2,765
Truck Stop Electrification	0	0	0	1	4	250
Total	12	175	6,139	37	478	15,352

Figure 254. SDG&E PYDFF Program Site Visit Ports and Capacity, EY2025 and PTD Sites

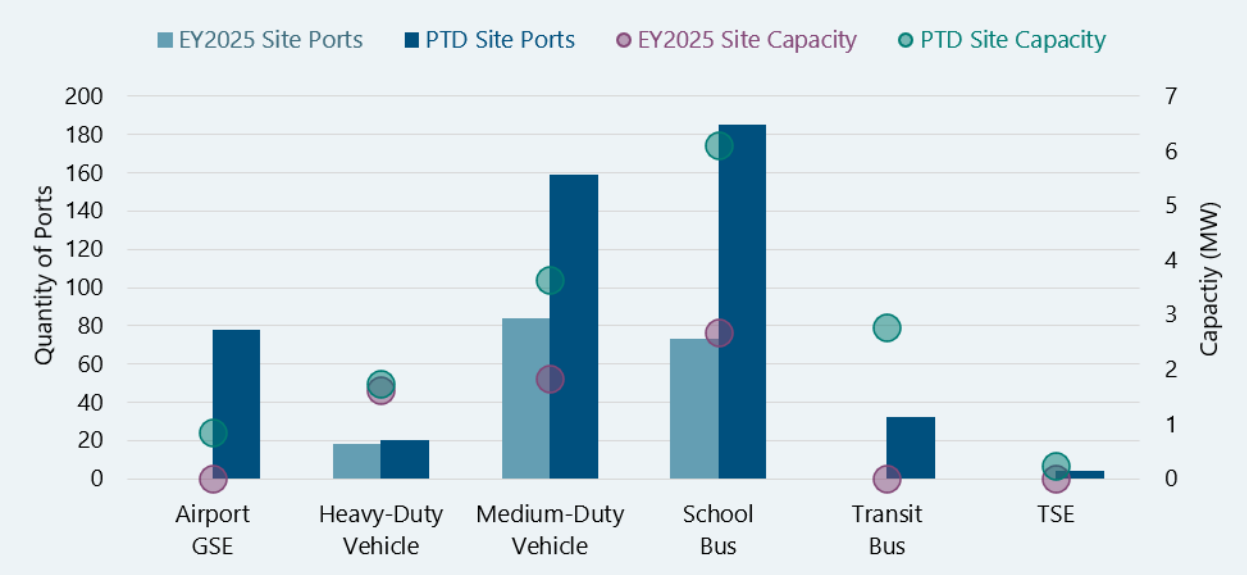
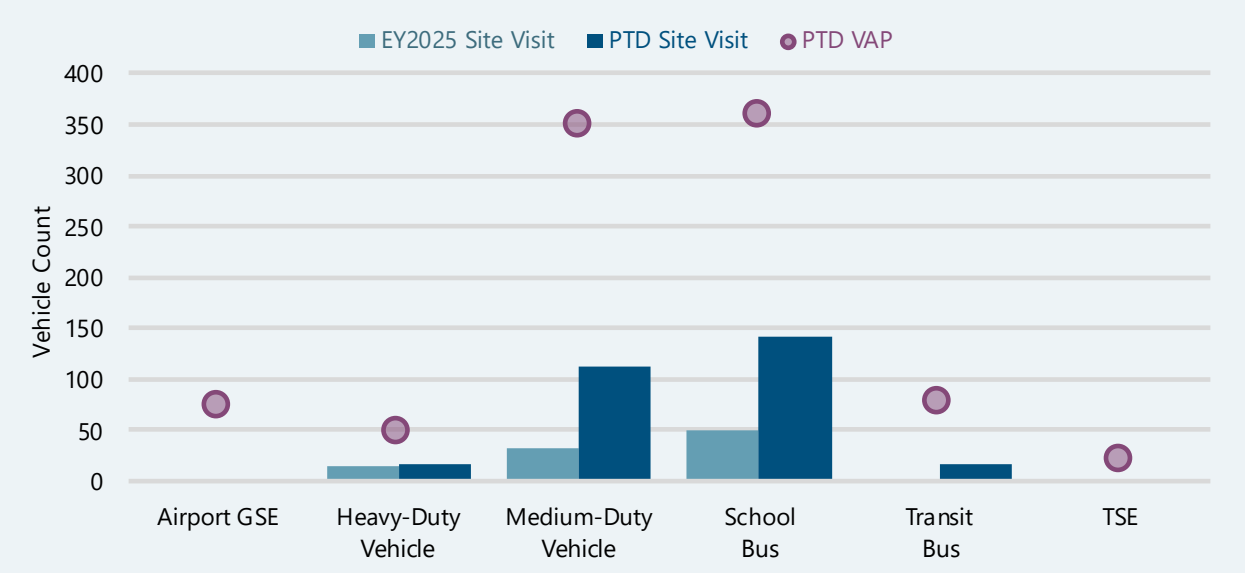


Figure 255 shows the count of vehicles noted through site visits compared with the number on 10-year VAPs. Market sectors closest to plan include medium-duty vehicle, heavy-duty vehicle, and school bus. In general, the Team expects differences between observed vehicles and total vehicles included in long term VAPs, as the Evaluation Team visits each site only once and does not update the count of vehicles for sites activated in previous years. Utility staff continue to follow up with sites from previous years to determine if they have acquired more vehicles.

Figure 255. SDG&E PYDFF Program Comparison of Verified Vehicles to Long-Term VAP



During site visits, the Evaluation Team reviewed charge management capabilities and electrical infrastructure, discussed future vehicle/equipment replacement plans (including future vehicle adoption) and public funding sources, and investigated whether fleets had an interest in on-site solar and/or battery storage. Site visits allowed the Evaluation Team to obtain direct feedback from the individuals involved with operations and to identify EVSP points of contact to obtain charging session data.

The Evaluation Team noted some continued challenges across the sites. Site staff reported maintenance, service, and reliability issues with both nascent and established vehicle and charging equipment manufacturers. Multiple fleets managers expressed uncertainty about the reliability of their charging equipment and their ability to schedule load management in a sustainable and effective manner. Although the delivered vehicles performed well, fleet managers were not confident that they could electrify their entire fleet with the current MDHD options.

Despite these challenges, staff from multiple sites noted that their communication with SDG&E program staff was very good and that they had been equipped with the tools and context to understand their site's progress through the PYDFF program. Site staff also consistently cited their vehicles' low noise and high performance.

The following section provides a summary of key observations and data collected during site visits.

Common Site Visit Findings Across Utility Programs

Like in EY2024, the Evaluation Team continued to see charging sites that supported multiple fleets, including large truck stop–type sites, vehicle dealer sites, and other sites that offer public charging.

Dealerships continued to participate in SB 350 programs across the state, with some constructing multiple sites. Dealerships offer charging to dealer operated vehicles and rental vehicles, and some make the site available to neighboring fleets. Several operators of other types of fleets also participated in one or more

Utility programs to construct multiple sites. Most of these fleets replicated the same infrastructure from site to site, while others modified the site design based on regional demand.

Fleets across all market sectors continued to express concerns over the long-term viability of vehicle OEMs, NSPs, and EVSE manufacturers.

Many fleet managers reported that they do not know how much they spend on utility bills for charging EVs or how these costs compare with the costs of using conventional fuels. They were also not sure whether reducing the cost of charging would be possible. Some of these fleets participated in a deep dive interview that examined the barriers to fleets implementing load management, which would allow them to shift some of their EV charging to periods of low-cost electricity. A summary of these interviews is in the *Statewide Section* of this report.

Medium-Duty Vehicle Site Visits Key Findings

The Evaluation Team visited eight medium-duty vehicle sites in EY2025. Three of these sites showed high infrastructure investment, despite small fleets and low electricity usage, which often resulted in underutilization and potential cost inefficiencies. Usage and site visit data show low EV adoption, multiple utility accounts per site, and limited load management practices due to a general lack of experience with fueling vehicles with electricity.

Several small medium-duty vehicle sites had multiple utility meters, likely increasing administrative and monthly costs without delivering significantly more operational benefits. One example is a site that included three separate meters (one for 480 V service and one for 208 V service for PYDFF and another for 208 V service for SDG&E's light duty program) serving only 10 charging ports. While SDG&E typically uses separate 480 V and 208 V transformers and separate meters for DCFC and L2 chargers, one vehicle dealership site used a single utility meter on a 480 V transformer for both DCFC and L2 ports, along with a step-down transformer to go from 480 V to 208 V. PG&E and SCE often use this configuration, but it is not common for SDG&E. This dealership site also had a separate meter installed on the same 480 V transformer and switchgear provided through the PYDFF program for another DCFC the dealership installed for customer use.

One notable market constraint for this sector is the discontinuation of the Ford Lightning F-150 in 2025, which many of the medium-duty vehicle sites included in their VAPs. This reduces the EV pickup truck options and slows adoption for fleets that were relying on these vehicles.

Overall, medium-duty vehicle sites reflect early-stage adoption characterized by cautious fleet uptake, limited operational optimization, and system designs that prioritize infrastructure deployment over efficiency or scalability.

Heavy-Duty Vehicle Site Key Findings

One heavy-duty vehicle site was activated in EY2025 which is a nationwide refuse fleet that has electrified several locations through the SCE Charge Ready Transport and PG&E EV Fleet programs. All sites followed a similar design process, using 180 kW dual-port DCFCs (nine at this location) to support deployment of two brands of vocational vehicles (Figure 256). The site's make-ready capacity was designed to support six

additional chargers in the future. The 18 ports are used to support daily operations of 13 heavy-duty EV and one medium-duty EV. These EVs have among the largest battery capacities on the market (400 kWh to 500 kWh), and the fleet uses half of the charging capacity for daily routes. Less than 15% of this site's monthly energy is consumed between 4 p.m. to 9 p.m., indicating strong load management. This charging pattern is similar to that of the five locations in PG&E and SCE territories, which may be attributable to the NSP the fleets are using.

Figure 256. SDG&E PYDFF Program Heavy-Duty Vehicle Site with McNeilus and Peterbilt EVs



School Bus Site Key Findings

School bus sites show a relatively structured approach to electrification, with several districts actively expanding infrastructure and refining their strategies over time. One school district stands out for its deployment of a large-scale project that integrates charging infrastructure with on-site solar, battery storage, and backup generation, and a subsequent expansion of charging infrastructure. The district engaged with a developer to design and build BTM charging infrastructure at the site and were able to secure more than $5 million in grants and incentives for the site. The first phase of the site is complete and includes 34 single-port 30 kW DCFCs and six dual-port 120 kW DCFCs (Figure 257) to support a current fleet of 37 IC buses, with 38 more expected in the future. The expansion phase, which was in construction at the time of the site visit, was designed to support electrification of most of the fleet.

Figure 257. Large SDG&E PYDFF Program School Bus Site with Solar and Storage Integration



The second school bus site was at a location that hosted the SDG&E V2G school bus pilot and had previously installed chargers under the PYDFF program. In the EY2025 phase, the site installed seven 50 kW DCFCs on the make-ready infrastructure built during the previous phase. Notably the site switched charging hardware and software providers to improve performance and load management capability, demonstrating a strong institutional commitment to long-term optimization. In addition to electric school buses shown in Figure 258, this site also operates Class 6 Mack EVs for food distribution to schools throughout the district.

Figure 258. SDG&E PYDFF Program School Bus Site with a Variety of EVs



The third school site installed twenty 30 kW DCFCs from InCharge, which is also the site's NSP, to support two Blue Bird and two IC electric school buses. Overall, the Evaluation Team has seen a significant trend this year of school districts in the San Diego region shifting toward lower-power (30 kW) DCFCs instead of higher-power DCFC and L2 charging. While these chargers allow for quicker charging sessions than with

L2 chargers, they increase the likelihood of demand-oriented costs and have higher procurement and installation costs than L2 EVSE with limited increased capacity.

Highlights

- The Evaluation Team visited all 12 sites that were activated in EY2025 spanning school bus, medium-duty vehicle and heavy-duty vehicle market sectors, accounting for 66 L2 and 109 DCFC ports with more than 6 MW of installed charging capacity.
- PYDFF has commissioned 37 PTD sites totaling 478 ports with more than 15 MW of installed charging capacity across six different market sectors.
- A large school bus site secured more than $5 million in grants and incentives to install solar generation, battery energy storage, and backup generation for emergencies, integrated with 46 DCFC ports.
- The first heavy-duty vehicle vocational fleet site was deployed in EY2025 with 14 Class 8 refuse trucks from two different OEMs. This fleet successfully implemented load management from the start of its operations.
- Most of the EY2025 commissioned sites had received vehicles and deployed EVs, but none of the sites the Team visited had fulfilled their VAP yet.
- Overall, medium-duty vehicle sites reflect early-stage adoption characterized by cautious fleet uptake, limited operational optimization, and system designs that prioritize infrastructure deployment over efficiency or scalability.

Deep Dives

The Evaluation Team conducted one deep dive in EY2025 for the PYDFF program. For deep dives, the Team selects sites that have significant demand, energy consumption, or installed charging capacity; a demonstrated ability to expand charging infrastructure; the presence of load management, unique vehicles, or charging equipment; a large fleet size; and a fleet manager who is willing to participate in the deep dive process.

The PYDFF deep dive site is a medium-duty vehicle logistics site operating Class 4 delivery vans at one location within SDG&E territory. The Team conducted an in-depth fleet manager interview and analyzed AMI and EVSP data as part of this deep dive.

Findings presented in this section are based on the fleet manager interview and data analysis. *Appendix A* presents a more detailed case study on this fleet.

Medium-Duty Vehicle Logistics Site

The Evaluation Team selected a medium-duty vehicle logistic site because of the fleet's operation of multiple sites across SDG&E and PG&E territory, with additional sites built out in PG&E territory. The fleet currently operates around 50 electrified sites in California. The operator plans to continue building out infrastructure and upgrading sites with more network capability, standardize equipment and vehicles, and implement network providers across all of its sites.

As of December 31, 2025, the operator had 21 BrightDrop electric delivery vans at its site in SDG&E territory, each operating between 80 and 150 miles per day. The vans operate in two shifts between approximately 7 a.m. and 6 p.m., separated by a brief return to the facility. The operator charges the vehicles using 11 25 kW dual-port BTCPower overhead DCFCs or 22 total ports and 275 kW of total nameplate power output. Charging primarily takes place in a single overnight shift despite the vehicles operating in two distinct shifts; this avoids energy consumption during the 4 p.m. to 9 p.m. peak rate period. The site is actively looking for an NSP to help manage energy consumption and does not currently utilize active load management. Rather, the site avoids the majority of the 4 p.m. to 9 p.m. period by plugging the vehicles in only after they return from their final shifts of the day, with a significant increase in demand occurring after approximately 6 p.m. and peaking around 8:30 p.m. This results in approximately 30% to 35% of the site's energy consumption occurring between 4 p.m. to 9 p.m.

Some of the operator's other sites use different charger manufacturers. However, the operator reported the best functionality and reliability with the BTCPower chargers and spoke highly of BTCPower's involvement and communication as key components of the chargers' uptime.

Highlights

- The fleet has found its vehicles and chargers to be reliable and is standardizing its equipment and vehicles across its sites.
- The charging stations do not currently have active load management but could shift additional load away from the 4 p.m. to 9 p.m. period by automating charging to start after 9 p.m. without conflicting with the vehicles' duty schedule. The fleet was actively looking for an NSP at the time of the site visit.
- The fleet has experienced the discontinuation of two electric delivery van models during the lifetime of the project and is currently working to find an alternative for the BrightDrop vans.

Co-Benefits and Co-Costs

Through deep-dive fleet manager interviews, the Evaluation Team explored co-benefits and co-costs associated with the PYDFF program's vehicle electrification sites as discussed below.

Fleet Manager Surveys

The Evaluation Team did not receive survey responses on co-benefits and co-costs for EY2025.

Deep Dive Fleet Manager Interviews

The Evaluation Team conducted a deep-dive interview with one SDG&E fleet manager to assess the co-costs and co-benefits of transportation electrification for fleets and fleet drivers. During the interview, the fleet manager noted two primary costs:

- **Difficulty sourcing vehicles in their sector.** The fleet originally contracted with a different manufacturer and model of vehicles but pivoted to BrightDrop following the original manufacturer's insolvency. With BrightDrop's subsequent discontinuation in late 2025, the fleet has reached out to other manufacturers in the space but noted relatively few players in the medium-duty vehicle sector compared with the light- and heavy-duty markets.

- **Lack of charging management capability.** Per the fleet manager, the site was unable to implement load management on its own, resulting in a high share of charging during the 4 p.m. to 9 p.m. period. This increased costs and reduced charging flexibility. The site is actively seeking a suitable station network partner to set up the chargers and enable automated load management.

The fleet manager the Evaluation Team interviewed had an overall positive experience with the PYDFF program, with their fleet maintaining reliable operations throughout the deployment process, and plans to continue expanding their electrification efforts.

Highlights

- Although the one interviewed fleet manager identified vehicle sourcing and lack of charging management capability as costs, they also expressed an overall positive experience with the PYDFF program.

Site Costs

The Evaluation Team conducted a cost analysis of 28 sites with fully closed-out finances as of December 31, 2025. The set of fully closed-out sites is smaller than the 39 activated sites due to the time lag associated with activities such as collecting receipts, paying invoices, and obtaining administrative approvals. Cost estimates presented here are in nominal dollars.

The 28 sites comprised 10 school bus sites, 13 medium-duty vehicle sites, two transit bus sites, one truck stop electrification site, one airport GSE site, and one heavy-duty vehicle. Sites had installed a mix of L2 and DCFC ports, averaging 11.5 ports and 349 kW of installed capacity per site in the program to date. For a discussion of site costs by market sector, see *Summary of Costs*. Of the 28 sites, 19 had Utility-owned BTM infrastructure, and nine had customer-owned BTM infrastructure.

Figure 259 shows the distribution of site-level costs of the 28 sites. The horizontal lines of the boxes show the 25th, 50th, and 75th percentiles of sites; the X denotes the mean site cost; and the three panels are defined as follows:

- **Utility Infrastructure Costs.** Actual site installation costs borne by the Utility for both TTM and BTM (or the BTM incentive when the site infrastructure is customer-owned), including all capital and labor costs.[123] This does not include the cost of the EVSE equipment or installation.
- **Ratepayer-Funded Costs.** Actual site installation costs borne by the Utility, including all capital and labor costs of TTM, BTM (or the BTM incentive if the site infrastructure is customer-owned infrastructure), and EVSE rebate.

[123] Utility Infrastructure costs are the same as the ratepayer-funded costs, except they do not include the EVSE rebates.

- **Estimated All-In Costs**. Estimated costs of installing the site borne by the Utility and the customer, including all capital and labor costs. The value is calculated by summing the actual TTM,[124] actual or estimated BTM,[125] and estimated EVSE costs.[126]

Figure 259. SDG&E PYDFF Program Per-Site Costs Organized by Three Perspectives, Across 28 Closed-out PTD Sites

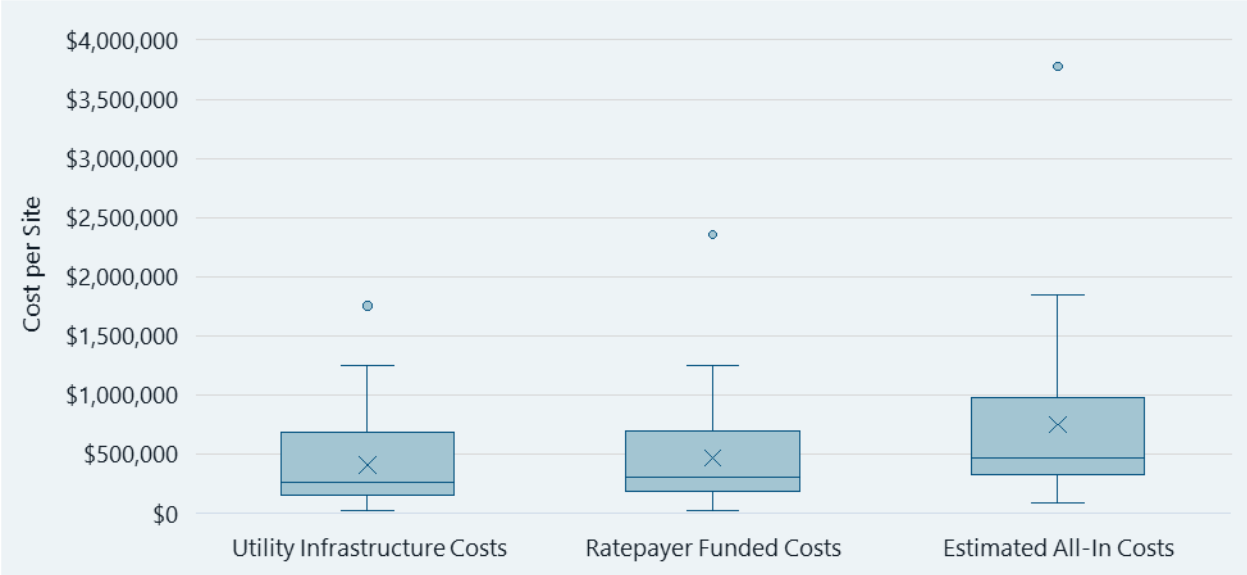


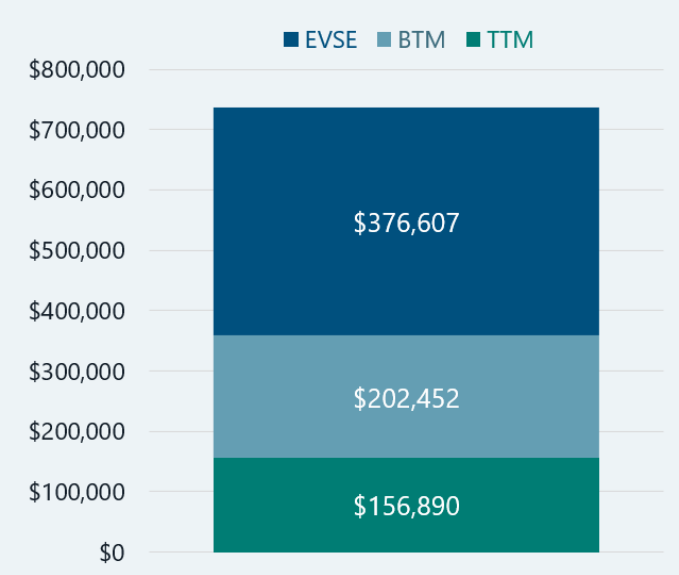
Figure 260 shows the average estimated all-in costs for the 28 sites. EVSE has the largest cost across the sites, followed by BTM and then TTM. Together, the average estimated all-in TTM, BTM, and EVSE cost is $735,949 through 2025.

[124] The Utility pays 100% of the TTM costs and therefore reports actual TTM costs to the Evaluation Team.

[125] The Evaluation Team receives actual BTM costs for sites with Utility-owned BTM. In total, 19 of 28 sites with fully closed-out financials have Utility-owned BTM. The Evaluation Team estimates other BTM costs using the relationship between installed kilowatts and BTM from other sites with actual BTM costs.

[126] Because the Utility does not record actual EVSE costs, the Evaluation Team estimated all-in EVSE equipment costs using assumptions of $3,000 per port for L2 ports and $45,000 per port for DCFC ports.

Figure 260. SDG&E PYDFF Program Average All-In Costs, Across 28 Closed-Out PTD Sites



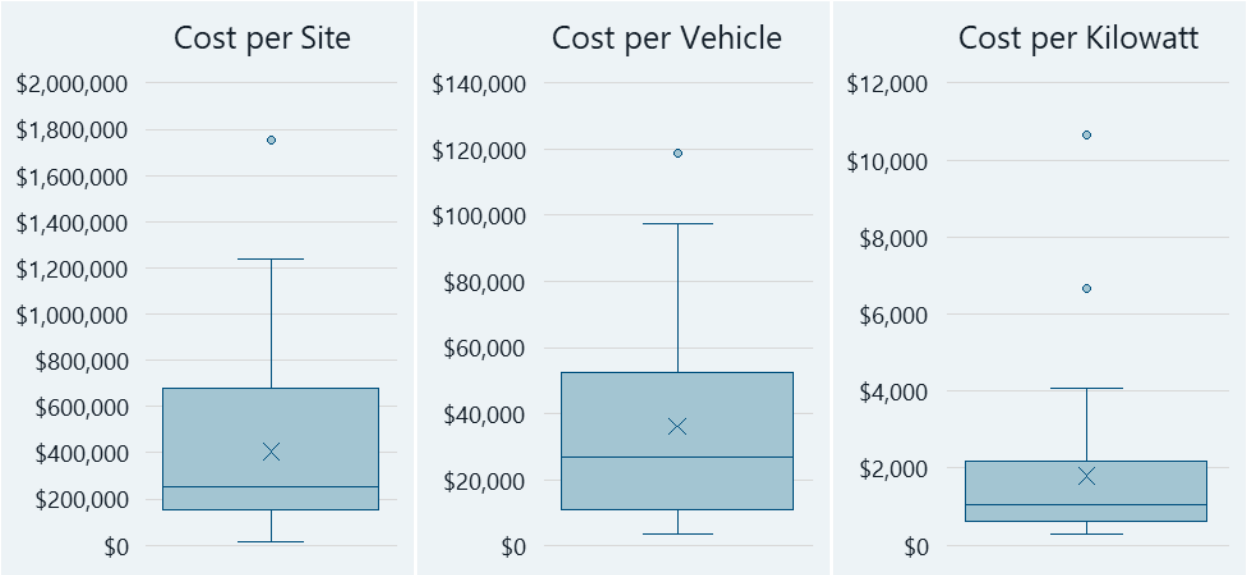
Source: The Evaluation Team calculated the costs shown in this figure by summing all TTM, BTM, and EVSE costs borne by SDG&E and the customer and dividing the total by 28 sites. Sites with customer-owned BTM have synthesized BTM costs.

Figure 261 shows the distribution of utility infrastructure costs (corresponding to the far-left panel in Figure 259) presented per site, per vehicle, and per kilowatt. The average Utility infrastructure cost of TTM and BTM borne by SDG&E across PTD sites was $401,565 per site,[127] $37,513 per vehicle, and $1,951 per kilowatt.[128] Although not shown, 33% of the SDG&E PYDFF program spending on infrastructure for financially closed-out sites to date has occurred in DACs, exceeding the program's 30% target.

[127] Calculated by summing all TTM and SDG&E-sponsored BTM costs and dividing by the number of sites. Number reflects maximum infrastructure rebate offered for sites that have not yet applied for rebates, which may vary significantly from actual infrastructure rebate amount paid.

[128] Calculated by summing all TTM and SDG&E-sponsored BTM costs and dividing by the sum of installed capacity.

Figure 261. SDG&E PYDFF Program, Utility Infrastructure Cost per Site, per Vehicle, and per Kilowatt for 28 Closed-Out PTD Sites



Highlights

- Estimated all-in costs paid by the customer and SDG&E vary widely between sites, with an average of $735,949 per PTD site.
- The average cost of SDG&E-sponsored TTM and BTM across PTD sites was $401,565 per site, $37,513 per vehicle, and $1,951 per kilowatt.
- 33% of Power Your Drive for Fleet program spending on infrastructure for financially closed-out sites to date has occurred in DACs, exceeding the program's 30% target.

Grid Impacts

This section describes grid impacts for the PYDFF program based on an analysis of energy consumed by and customer bills for operational charging stations installed through the PYDFF program in EY2025.

Data Sources

The primary data source used for the analyses detailed in this section is energy usage data provided in regular 15-minute intervals from the AMI utility meter. Other data sources include customer bills, LCFS program information, and charging session–specific data provided by NSPs. There are several important differences between AMI and NSP data. While AMI data reflects only energy usage, NSP data includes session start and stop times, the duration of a vehicle's connection to a charging port, the duration of a vehicle actively pulling power, and the specific port used for a session. AMI meters track standing loads (such as those the EVSE uses for communications, cooling, active power converters, solenoids, and screens), which NSPs typically cannot do. In instances where AMI data is missing from the dataset, the Evaluation Team uses NSP data to fill the gaps.

Summary of Grid Impacts

Table 109 presents the estimated PYDFF program grid impacts.

Table 109. SDG&E PYDFF Program Grid Impacts

Impact Parameter	Actual 2025 [a]	PTD Actual	10-Year Projection PTD
Operational Sites	12	37	37
Installed Capacity (MW)	6.1	15.4	15.4
Electric Energy Consumption, MWh			39,045
On-Peak (4 p.m. to 9 p.m.) MWh (and % of total)			N/A
Maximum Demand, MW (with date and time)	3.2 (12/5/25 10 a.m.)	3.2 (12/5/25 10 a.m.)	N/A
Maximum On-Peak Demand, MW (with date and time)	2.6 (9/9/25 5:15 p.m.)	2.6 (9/9/25 5:15 p.m.)	N/A

[a] Energy consumption, peak consumption, and demand data are based on PTD activated sites for calendar year 2025.

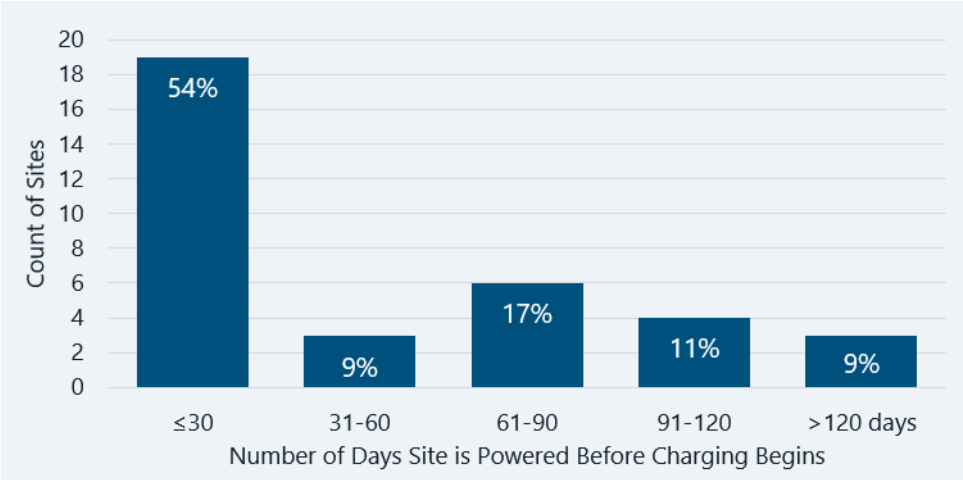
Energy Trends

Site Startup

The Evaluation Team examined the duration between PYDFF site activation and operational status to illustrate the timing between readiness of charging infrastructure and actual vehicle charging.

AMI data demonstrate that approximately 80% of sites were operational within 90 days of activation, as illustrated in Figure 262, and over 50% were operational within 30 days. Less than 10% of sites took over 120 days to reach operation, which is significantly less than trends noted in other Utility MDHD programs. The number of sites reaching operation within 30 days of activation also improved, growing from 45% in EY2024 to 54% in EY2025.

Figure 262. SDG&E PYDFF Program Percentage of Sites by Days between Activation and Operation for PTD Sites



Consumption and Maximum Demand

Figure 263 depicts the growth of SDG&E's monthly energy consumption and maximum demand for all operational sites in the PYDFF program to date. In EY2025 consumption continued to grow while maximum demand was relatively stable.

PTD sites in the PYDFF program collectively reached 3.2 MW of demand in late 2025, with installed capacity increasing by 6 MW in the beginning of the year to 15.2 MW. A drop in demand in July aligns with summer when school district bus operation is limited. One-third of sites in the PYDFF portfolio are school bus sites, which has a significant impact on overall demand for the program. As shown in Figure 263, demand returned to pre-summer levels in August when schools are back in session.

Figure 263. SDG&E PYDFF Program Monthly Energy Consumption and Maximum Demand

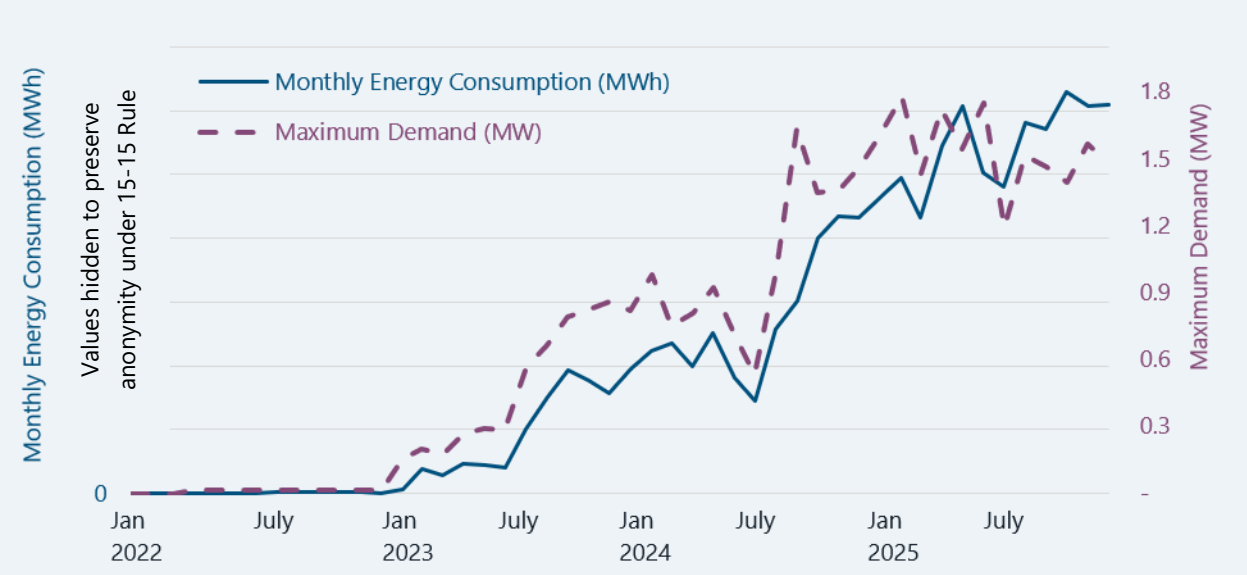


Figure 264 provides insight into monthly energy consumption trends of activated sites by program reporting year. Sites activated prior to EY2023 continue to show slow growth in monthly energy consumption. Sites activated in EY2023 appear to have reached fairly consistent operations, with consumption hovering around 150 MWh monthly. Sites activated in EY2024 had a similar plateau throughout the end of 2024 and 2025. Sites activated in EY2025 appear to be early in operational maturity based on monthly energy consumption, which is expected to increase in EY2026. It is also important to note that several sites activated in EY2025 had yet to receive vehicles at the end of EY2025 and therefore have not displayed any consumption to date.

Figure 264. SDG&E PYDFF Program Monthly Energy Consumption of Activated Sites Grouped by Initial Reporting Year

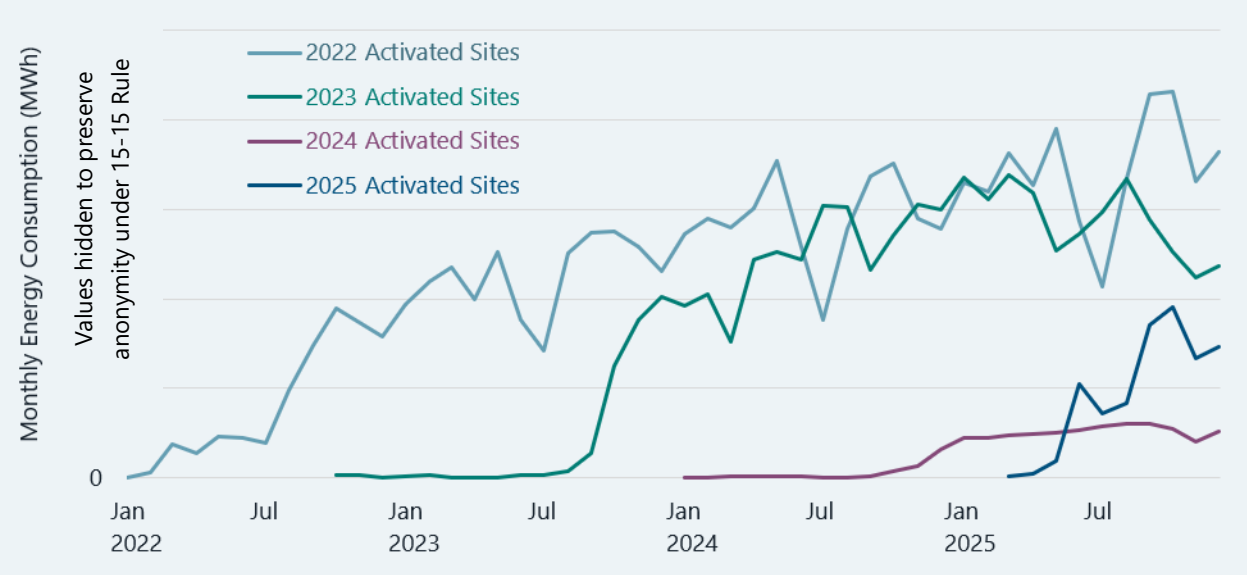
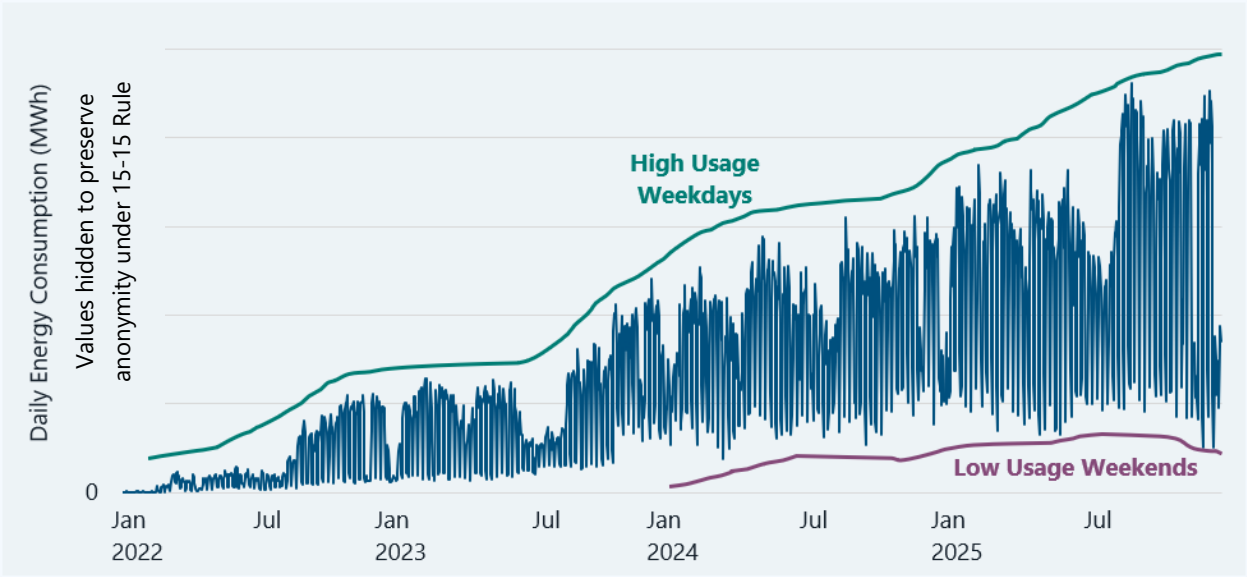


Figure 265 shows daily fluctuations in consumption, with wide variations between weekdays (upper bound) and weekends (lower bound). Despite relatively flat consumption between 17 MWh and 23 MWh in the second half of EY2025, daily energy consumption is likely to grow as the newer sites receive vehicles and put them into service. Notably, weekends show consistent daily consumption between 2 MWh and 8 MWh throughout EY2024 and EY2025, which is primarily attributable to the transit bus market sector.

Figure 265. SDG&E PYDFF Program Daily Energy Consumption for PTD Sites



Maximum demand for PTD sites continues to grow each year. During the first half of EY2025, peak daily demand averaged around 1.5 MW, reaching over 2 MW on several days. Average demand increased

significantly in the second half of EY2025, with the majority of days exceeding 2.5 MW and several days seeing a peak of above 3 MW. The peak demand shown in Figure 266 represents approximately 20% of the total installed capacity of 15.2 MW for PTD sites.

Figure 266. SDG&E PYDFF Program Maximum Demand for PTD Sites

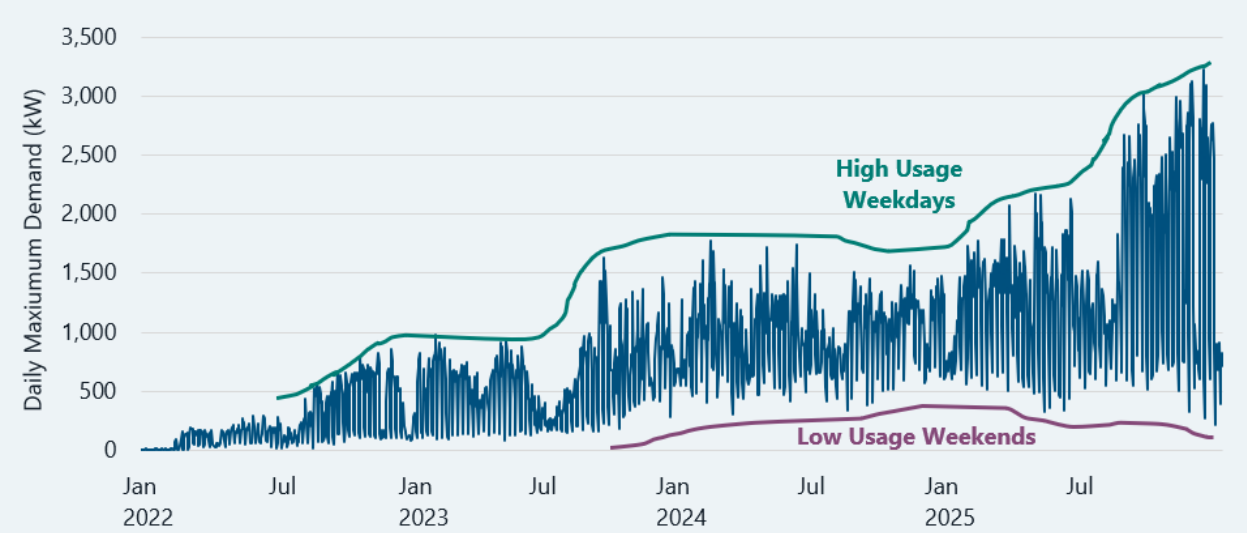
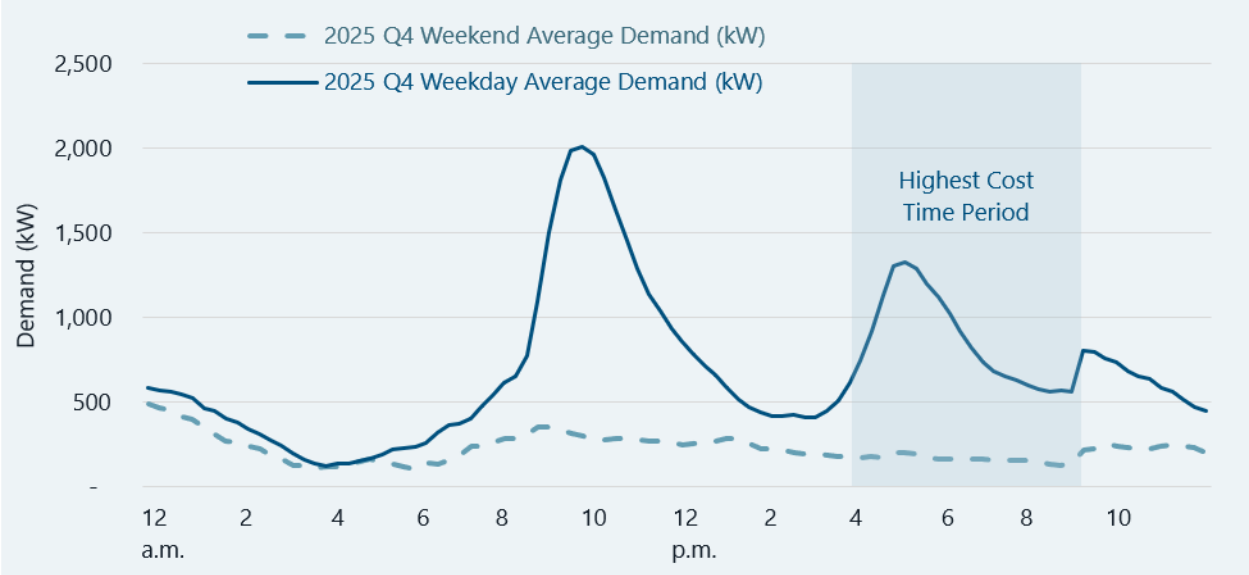


Figure 267 depicts average weekday and weekend load curves in the fourth quarter of EY2025, which showed the most consistent usage and is the period with demand most representative of EY2025 average trends. Weekend operations are fairly consistent, with demand around 250 kW from 10 a.m. until midnight. Weekend demand increases to approximately 500 kW beginning at 12 a.m., as a result of charging vehicles at the end of the work week. To improve cost efficiency, fleets that primarily operate Monday to Friday can choose to further delay Friday evening charging until 10 a.m. on Saturday mornings when energy is both cleaner and less costly than overnight (SDG&E rates now include a Super Off Peak daily from 10 a.m. until 2 p.m.)

During the weekday, three load humps correspond with timing of school bus charging. Also interesting is the short spike at 9 p.m. from a small number of fleets using load management to avoid consumption during the higher cost period of 4 p.m. to 9 p.m. The effect from load shifting is less than for other Utility programs, which show the highest demand at 9 p.m. in alignment with lower cost energy.

School bus fleets are unique in that they return to base midday to charge regardless of whether the site uses load management; this is evident from the higher demand during the morning and afternoon than in late afternoon and evening. The impact of load management reduces the late afternoon maximum while creating a sharp, albeit small ramp in the evening.

Figure 267. SDG&E PYDFF Program Average Weekday and Weekend Q4 2025 Load Curves

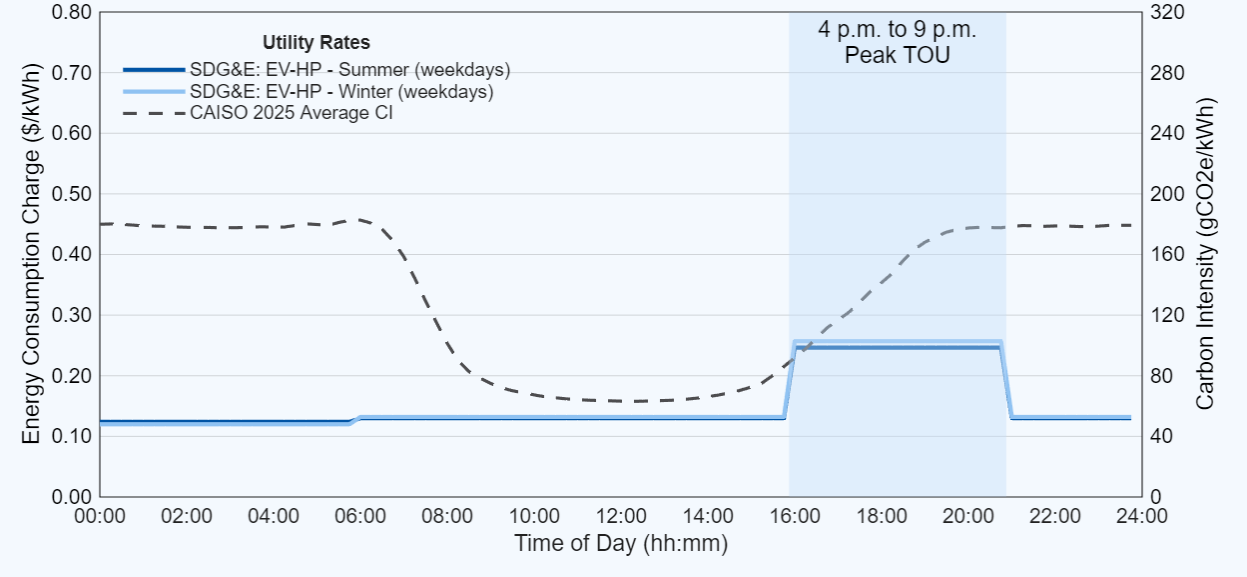


Load Management and Charging Flexibility Analysis

This section describes analyses around load management and charging flexibility. Load-managed sites are those that adopt techniques to avoid charging vehicles during periods of peak energy prices. The analyses consider sites to be load-managed if they exhibited consistent load management regardless of when load management was implemented during the year; otherwise, they are labeled as non-load-managed.

SDG&E's on-peak TOU period occurs each day from 4 p.m. to 9 p.m. During those peak hours, energy costs in 2025 for sites under the EV-HP rate structure in SDG&E's PYDFF program were approximately $0.25/kWh and were half that during all other time periods (off-peak TOU rates were $0.13/kWh and super off-peak rates were $0.12/kWh, with only slight differences for summer and winter periods). Figure 268 displays these TOU rates as they apply to summer and winter weekdays for SDG&E EV-HP. In many cases, lower-cost TOU periods correlate with lower carbon intensity of the grid, as indicated by the dashed line in the figure, which shows the CAISO 2025 average carbon intensity (gCO_2e/kWh). As the actual carbon intensity of the grid varies continuously by time of day and day of year, this reference line indicates the time-of-day average across all days in 2025.

Figure 268. SDG&E PYDFF Program Hourly TOU Electricity Rates and Average Carbon Intensity in 2025



The Evaluation Team periodically reviews data on a site-by-site basis throughout the year to identify load-managed sites. Visiting sites in person and speaking to fleet managers also provides context around load management intent and activity. When accounting for demand-related costs, information about charging flexibility can help the Team estimate the minimum rate a vehicle can charge to mitigate and minimize demand.

Three sites appear to show strong load management based on trends of dropping load at 4 p.m. and increasing load at 9 p.m. as well as low proportion of consumption during the high-cost period as mentioned above. However, site staff at one of these sites shared that their charging operations naturally align with the optimal charging strategy in that charging typically occurs in the morning for short periods and that they will instruct staff to try to follow that schedule more frequently. Another four sites showed intermittent load management in 2025 including a new site with relatively little usage through the end of the year. Two others that have stopped conducting load management mentioned ongoing challenges with their hardware and software vendors, one during a site visit and the other during a deep dive interview discussing load management barriers and solutions in the *Statewide* section of this report. Two other sites formerly using load management no longer occupy their original locations.

Load management is evident in several ways:

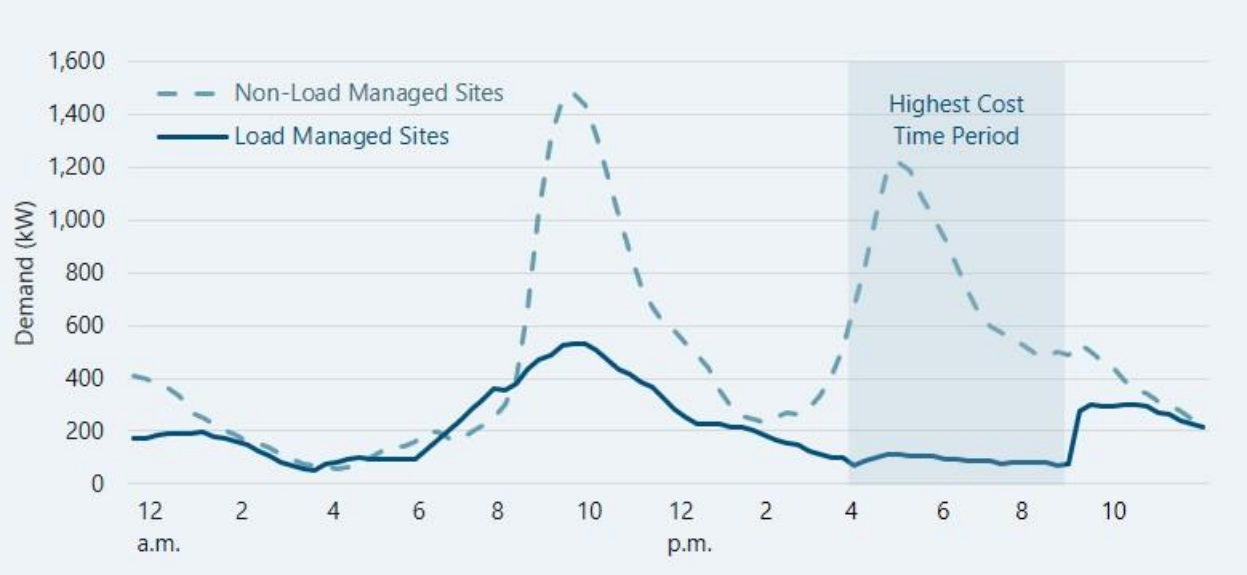
- Load spikes quickly around 9 p.m.
- Charging often drops off steeply at 4 p.m.
- The proportion of total monthly energy consumption between 4 p.m. and 9 p.m. is often below 10%.

Figure 269 illustrates the differences in electricity demand for load-managed and non-load-managed sites (determined using consumption data). As shown, load-managed sites have consistently low demand

throughout the highest-cost time period; conversely, non-load-managed sites show a second demand peak at 5 p.m., aligning with the end of the workday. As detailed further in the *Charging Flexibility* section, nearly all of this high-cost charging could be shifted to lower-cost time periods.

The amount of unmanaged load in EY2025 also increased significantly, with a peak of 1,500 kW compared with 400 kW in EY2024. Prior to EY2025, maximum demand for load-managed sites was similar during early afternoon and at 9 p.m. This group of sites now shows slightly lower demand at 9 p.m.

Figure 269. SDG&E PYDFF Program Load-Managed and Non-Load-Managed Site Demand, 2025 Q4 (High Consumption and Demand Months), PTD Sites



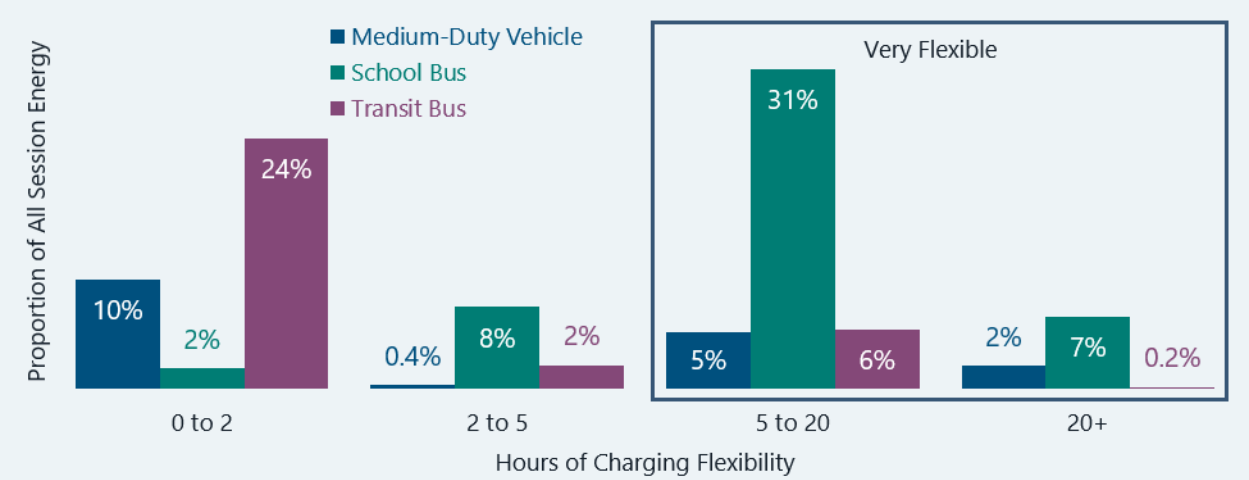
Charging Flexibility

The Evaluation Team used sites' charging data to determine the amount of time vehicles are connected to a charging port but not actively consuming energy. This allowed the Team to assess charging flexibility, or the ability for a vehicle to shift charging from periods of high-cost electricity to low-cost electricity without impacting vehicle operations.

Site visits allowed the Evaluation Team to confirm vehicles' make, model, and battery size, all of which affect charging flexibility; to get information about fleets' operational characteristics; and to offer feedback based on information we gathered. For instance, many school bus charging sessions use less than half of the vehicle's battery capacity. Providing feedback to operators about historical usage trends like charging session size in relation to battery size and available time to charge may help inform charging plans.

Figure 270 shows the relative charging flexibility of various vehicle market sectors, using only charging sessions that took place partially or entirely during periods of highest-cost electricity and omitting charging sessions that did not overlap with the period between 4 p.m. and 9 p.m.

Figure 270. SDG&E PYDFF Program Charging Flexibility for PTD Sites in Sessions Overlapping the Time Period Between 4 p.m. and 9 p.m.



Overall, each market sector shows significant charging overlap with the highest-cost period, including 48% of charging time for school bus, 32% for transit bus and 17% for medium-duty vehicle sectors. However, these market sectors have enough flexibility to allow them to shift a proportion of their energy consumption to a lower-cost period.

For example, 38% of total energy consumed by the school bus sector unnecessarily occurs during the highest-cost time period and has the flexibility to be shifted to a lower-cost time period. Because the period of highest-cost electricity lasts for five hours (4 p.m. to 9 p.m.), a charging session with up five or more hours of charging flexibility can fully shift consumption from on-peak to off-peak periods. Charging sessions with less than five hours of charging flexibility (almost 25% of all sessions) will still benefit from adopting load management by shifting a portion of consumption to periods of lower-cost electricity.

Fleets operating a single shift are usually able to benefit the most from load management, while fleets operating multiple daily shifts face the most challenges to leveraging load management, as vehicles charge throughout the day. However, while it is more difficult for sites with multiple shifts to avoid charging during the 4 p.m. to 9 p.m. period, these sites also tend to have consistent use at all times of day. This can avoid typical peak consumption aligned with the end of the typical workday (5 p.m.) and somewhat reduces the proportion of charging from 4 p.m. to 9 p.m., resulting in lower average energy costs on a kilowatt-hour basis.

Charging flexibility can also be assessed based on vehicle battery capacity and actual operations. For example, if a vehicle has a 100 kWh battery, but uses 65 kWh daily, the vehicle will have a 35 kWh buffer. This storage capacity could be used to mitigate charging during times of high pricing. The fleets shown in Figure 270 have a combined total of 50 MWh of on-board battery storage capacity and daily consumption of around 20 MWh, offering a further opportunity for load shifting.

Costs and Billing

The total sum of the monthly billing costs for activated sites in the program to date amounts to $2.7 million. The following section examines utility cost and billing trends based upon the time of day charging takes place and the relative size (low, medium, or high) of billing months in kilowatt-hours. This analysis may help encourage fleets to review their utility bills to compare performance against other program participants and understand what electricity costs may be achievable through load management. The Evaluation Team's review of billing data focuses on the average unit cost of a kilowatt-hour for a given site for a billing month compared with the TOU-based tariff cost of energy.

A unique component of the PYDFF program is that several school bus sites have V2G capability; however none of these sites have employed this capability to date. In the future, evaluation of billing will be more complex for sites that have used V2G to participate in energy arbitrage (similar to net energy metering with solar) or special programs (such as emergency load reduction or demand response programs).

It should also be noted that in January of 2023, SDG&E filed a General Rate Case, which included a request to classify the 10 a.m. to 2 p.m. time period as a super-off-peak period year-round, similar to the rate structure offered by SCE and PG&E.[129] That update was implemented in spring of 2026 and therefore did not impact the EY2025 analysis.

NSPs' load management capabilities and the rate at which fleets adopt load management impact costs and energy trends. By the end of 2025, nearly 10 NSPs were servicing SDG&E customers in the PYDFF program, with nearly all customers of two NSPs displaying use of load management to minimize consumption during high-cost periods. The remainder of the NSPs either do not offer or have shown very little use of that capability.

An influential factor in the billing analysis is that many fleet operators are unaware of their energy use and charging costs even though most NSPs make this data available. Often a site host's finance office receives utility bills but does not share information with fleet operators that would enable them to compare energy costs of the various fuel types in their fleets. The Evaluation Team uses energy trends as discussion points during site visits if operations have started. Many fleet operators said they had not seen these data trends prior to the evaluation site visits.

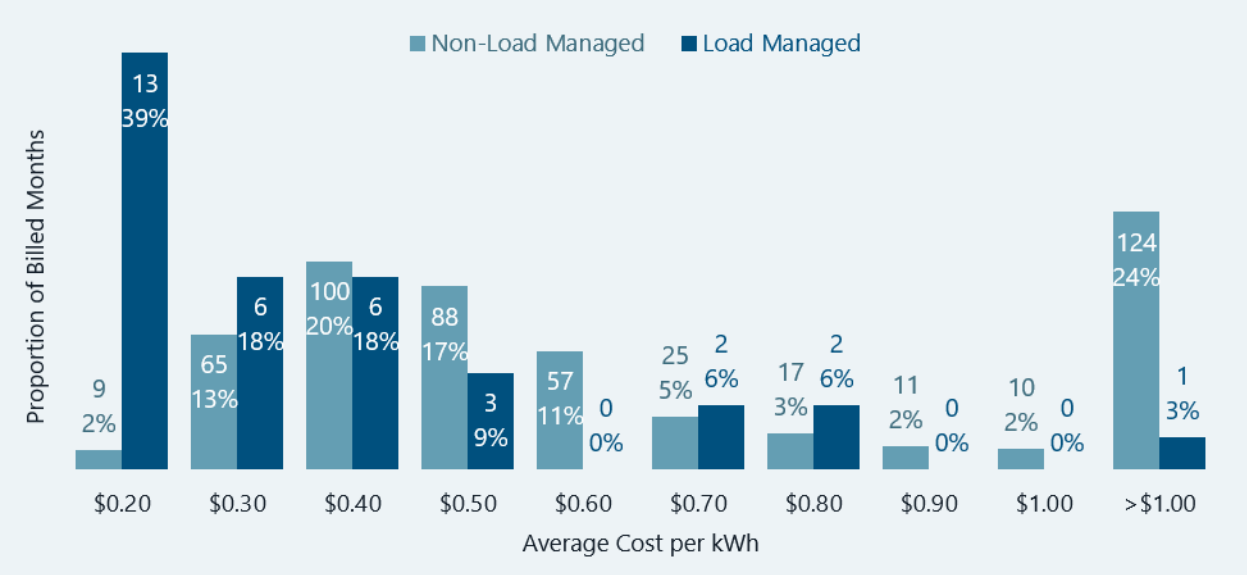
Figure 271 shows the distribution of average monthly electricity costs per kilowatt-hour for PTD sites for which at least six months of billing data was available in EY2025. SDG&E base rates range between $0.12/kWh and $0.25/kWh, before adding demand capacity bucket fees, services, and taxes. As shown in Figure 271, $0.20/kWh is the lowest achievable average electricity cost within normal operations, with only a few outlier billing months showing less than $0.10/kWh. Thirteen percent of billing months have average costs between $0.20/kWh and $0.30/kWh, and 36% of billing months have average costs between $0.30/kWh and $0.50/kWh. Notably, 22% of billing months have average costs over $1.00/kWh,

[129] Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design: Prepared Direct Testimony. January 17, 2023. www.sdge.com/sites/default/files/regulatory/A2301XXX_SDGE%202024%20GRC_Phase%202_Chapter%203_Rate%20Design.pdf

however it is important to note that many of these are sites with very low monthly consumption, therefore monthly subscription and demand charges are spread of a limited number of kWh, significantly increasing average costs.

SDG&E uses capacity subscriptions, meaning that instead of a per-kilowatt fee, SDG&E billing uses increments of either 10 kW or 25 kW allotments and includes overage fees. SDG&E continues to help customers avoid overage fees by automatically enrolling customers in the next highest capacity tier. This billing practice has helped to mitigate the overall average unit cost of energy.[130]

Figure 271. SDG&E PYDFF Summary of Average Monthly Electricity Cost

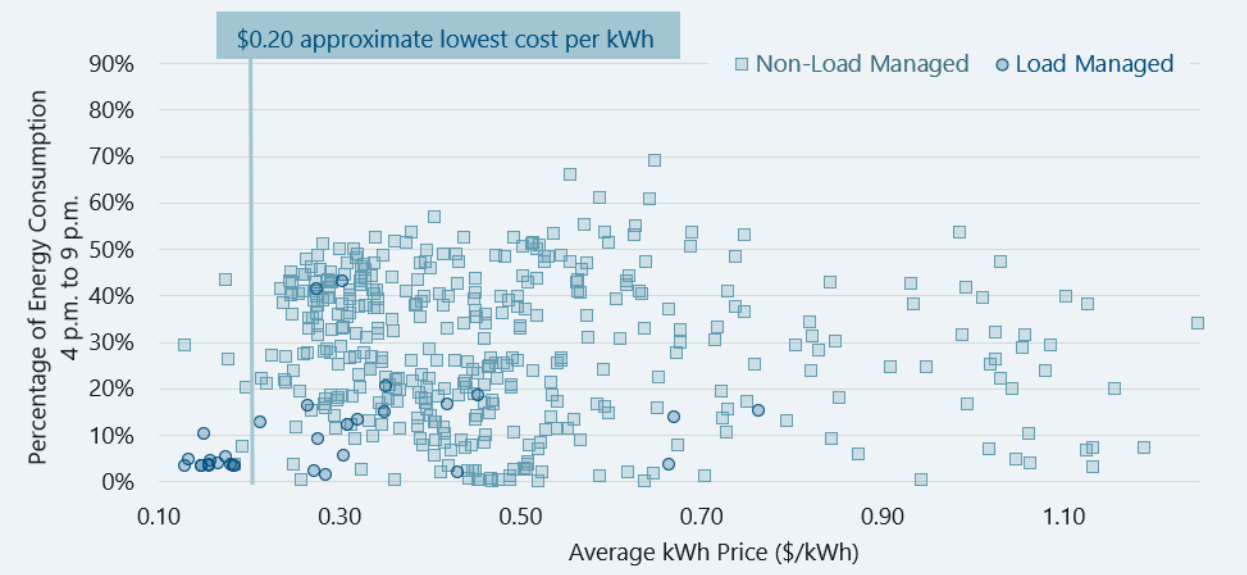


532 EY2025 billing months which includes some overlapping billing months in January and December.

Figure 273 shows all 2025 billing months with color coding by whether or not the fleet was observed to have used load management in 2025. The data points show that load-managed billing months trend to lower average energy costs, which is a direct benefit to the fleet. This also shows that these fleets consume lower proportion of energy between 4 p.m. and 9 p.m., which benefits ratepayers and utilities.

[130] A single site incorporates solar generation on its EV account, and those data points were not included here.

Figure 272. SDG&E PYDFF Program 2025 All Billing Months Average Electricity Costs per Kilowatt-Hour for Load-Managed and Non-Load-Managed Sites



To better highlight energy and billing trends, Figure 273 through Figure 277 show these trends across sites, grouped by high, medium and low billing months relative to total megawatt-hours consumed. Each dot represents a billing month.

Figure 273 provides a comparison of the average energy price for sites with the largest billing months (greater than 15 MWh) and the proportion of energy consumed during the peak period of 4 p.m. to 9 p.m. These sites show a trend of increasing average cost per kilowatt-hour when the proportion of charging between 4 p.m. and 9 p.m. increases.

Figure 273. SDG&E PYDFF Program Percentage of Monthly Energy Consumed from 4 p.m. to 9 p.m. vs. Average Energy Price for High-Consumption Billing Months (>15 MWh), PTD Sites

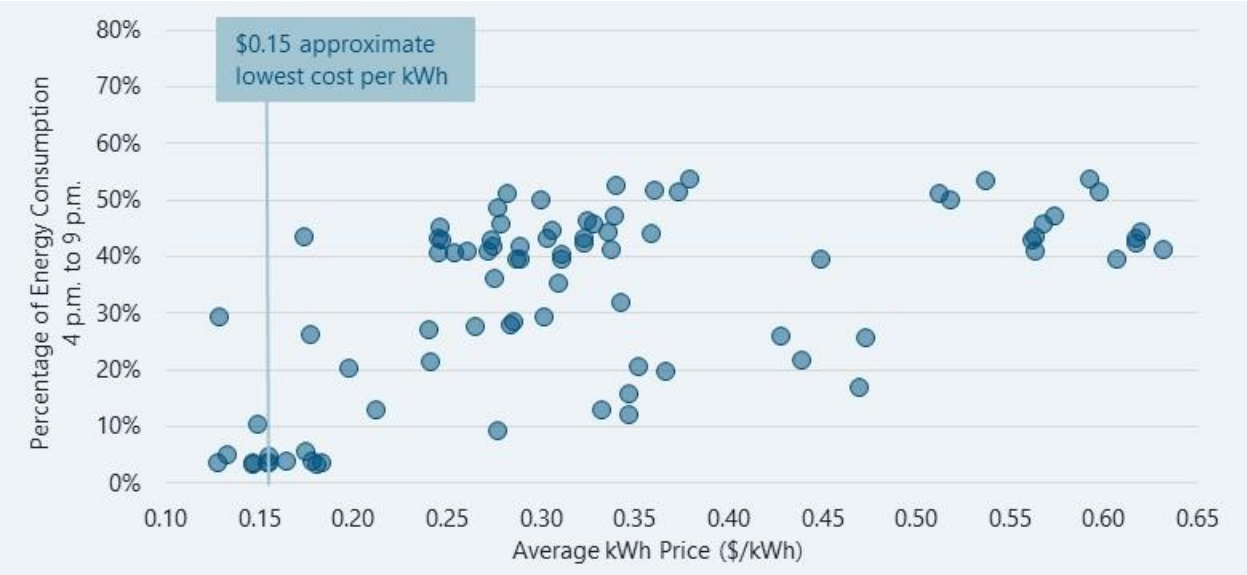


Figure 274 shows analysis of the same group of sites comparing total consumption against average electricity cost. This shows that sites with the largest billing months receive some of the lowest average per kilowatt-hour electricity costs, with a cost of $0.15/kWh to $0.20/kWh for the best performing sites, which are typically those using load management. This provides a baseline for cost reductions that fleets with higher electricity costs could achieve by adopting load management.

Figure 274. SDG&E PYDFF Program Total Monthly Energy Consumed vs. Average Energy Price for High Consumption Billing Months (>15 MWh), PTD Sites

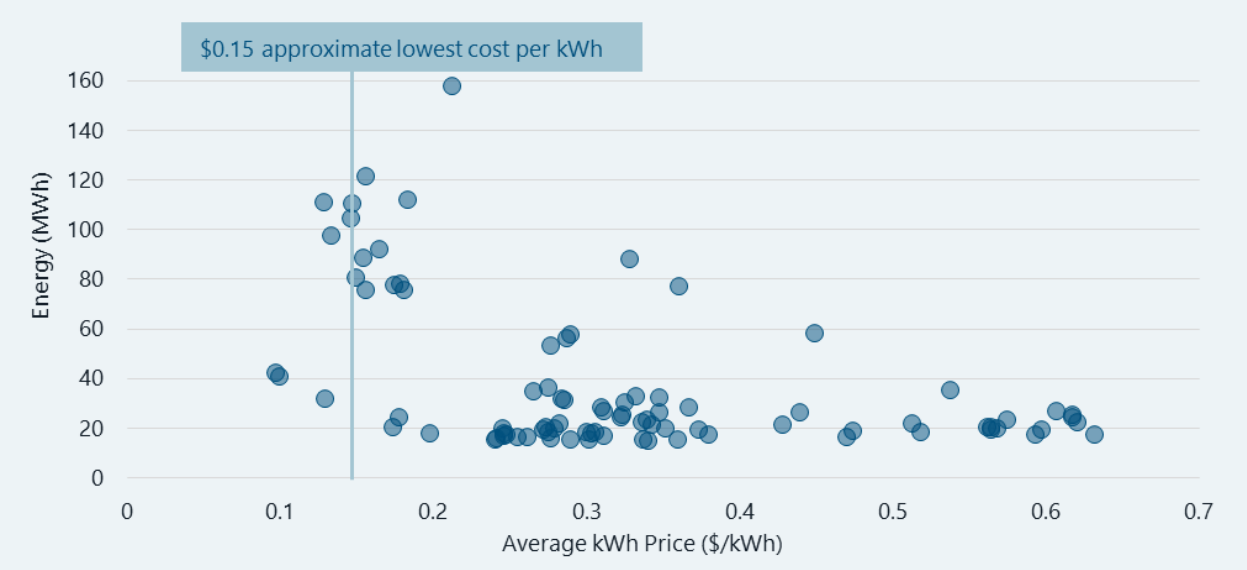


Figure 275 provides a comparison of the average energy price for sites with medium billing months (5 MWh to 15 MWh) and the proportion of energy consumed during the peak period of 4 p.m. to 9 p.m. Overall this batch of sites shows less opportunity to achieve the lowest cost of electricity below $0.20/kWh and a higher range of costs compared with sites with large billing months.

Figure 275. SDG&E PYDFF Program Percentage of Monthly Energy Consumed from 4 p.m. to 9 p.m. vs. Average Energy Price for Medium-Consumption Billing Months (5 MWh to 15 MWh), PTD Sites

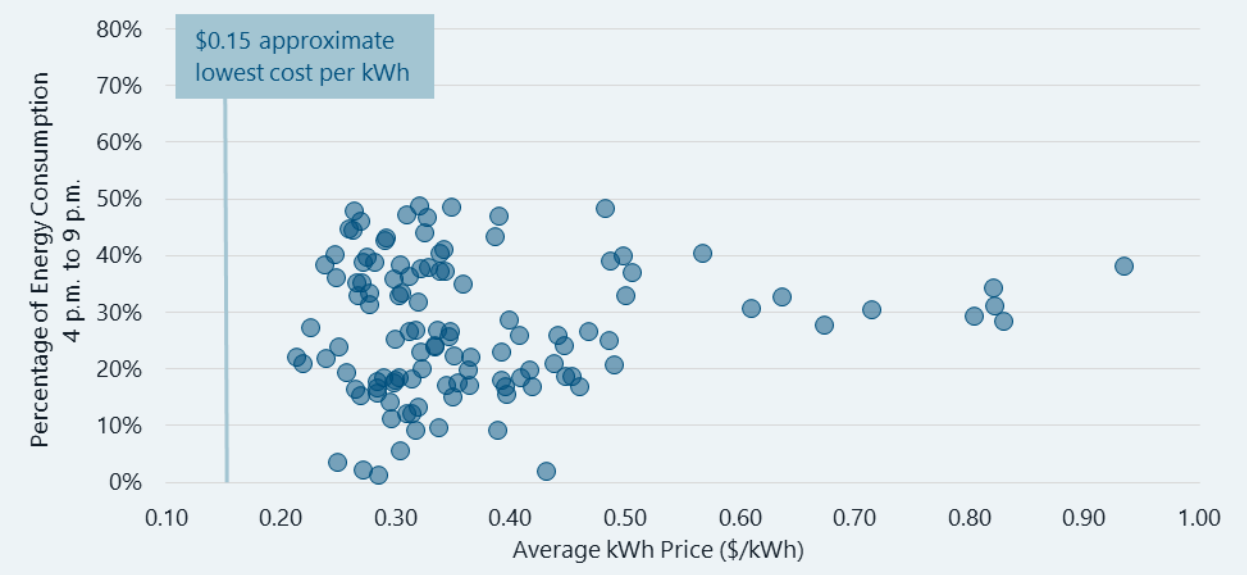


Figure 276 illustrates the relationship between energy consumed and the average cost per kilowatt-hour for medium-size months of consumption from 5 MWh to 15 MWh. Medium billing months may show a slight trend of the average cost per kilowatt-hour being inversely related to energy consumption (i.e., higher monthly consumption seems to result in lower average cost). This is possibly due to fixed costs, such as demand charges, taxes, and fees, being spread over a greater volume of kilowatt-hours. Most billing points in this group are between $0.25/kWh and $0.35/kWh with a few sites reaching between $0.60/kWh and $0.70/kWh.

Figure 276. SDG&E PYDFF Program Total Monthly Energy Consumed vs. Average Energy Price for Medium Consumption Billing Months (5 MWh to 15 MWh), PTD Sites

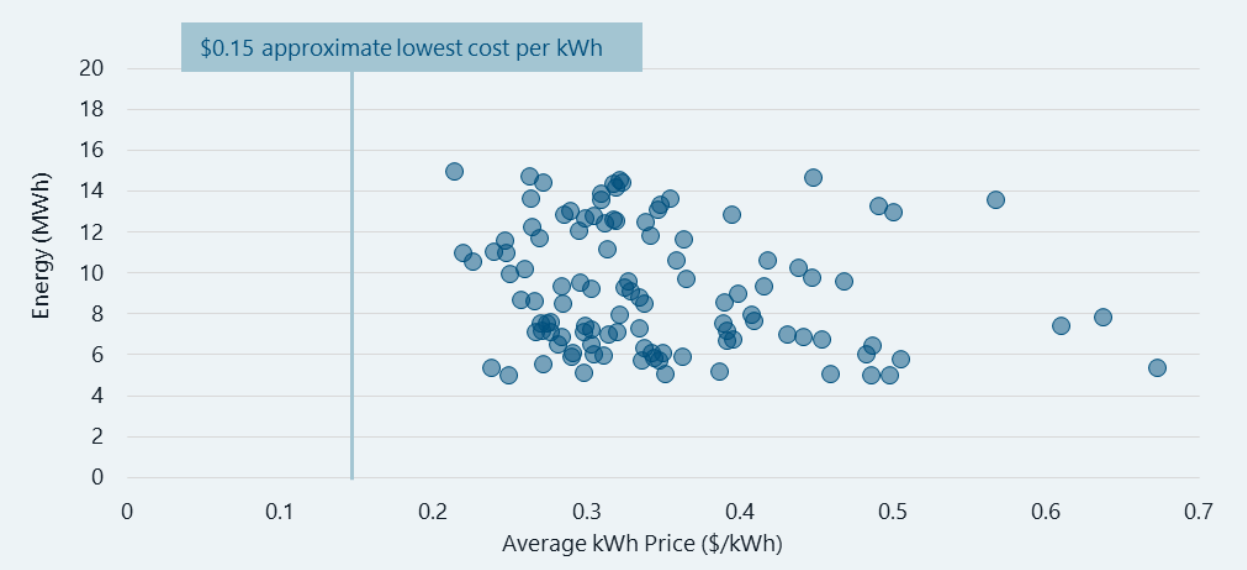
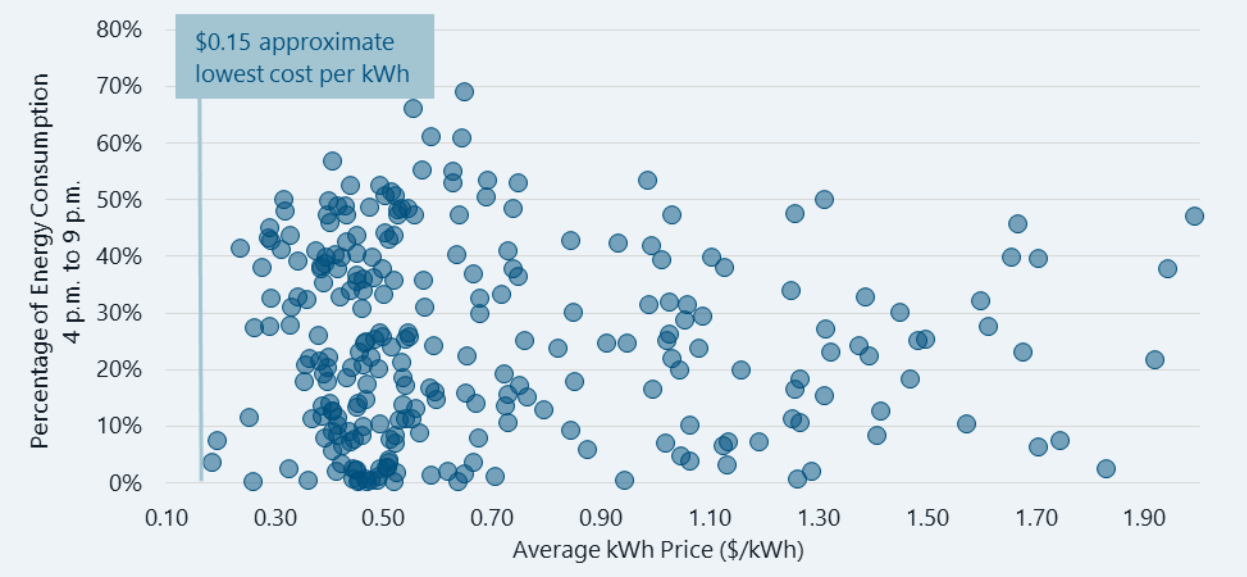


Figure 277 illustrates the relationship between the percentage of on-peak energy consumption and the average cost per kilowatt-hour for low monthly consumption (<5 MWh). The figure shows that low billing months typically have a higher cost per kilowatt-hour, with an average cost of approximately $0.50/kWh and many sites having billing months with costs exceeding $1.00/kWh. Months with the lowest energy use often occur early in site operations and can include charger commissioning activity and/or charger standby load before regular vehicle operations and charging begin. Sites at this stage of operation are unlikely to have adopted load management and often show irregular charging behavior.

Figure 277. SDG&E PYDFF Program Total Monthly Energy Consumption vs. Average Energy Price for Low Consumption Billing Months (<5 MWh), PTD Sites



Electricity Cost and Emissions Optimization Analysis

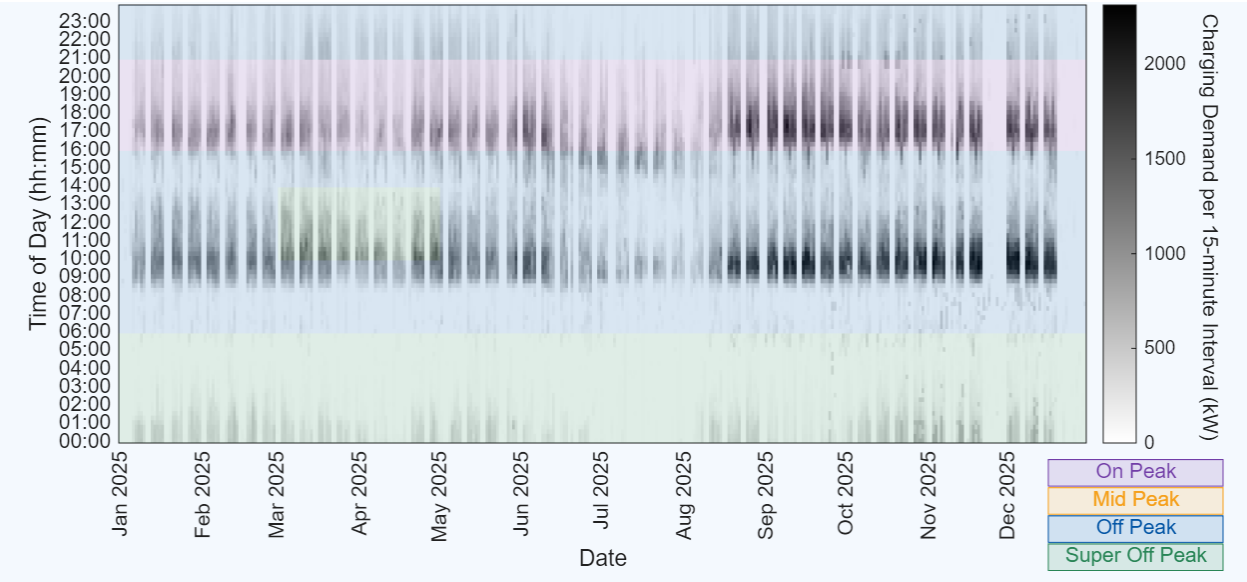
This section builds upon the grid impact findings above to include an analysis of hypothetical customer bills and emissions under an optimal load management scenario, assuming perfect load management across all sites. While real-world constraints—such as from technology, operations, and education—currently prevent ideal load management, the findings shed light on its long-term potential. To quantify the potential benefits of using load management, the Evaluation Team analyzed observed outcomes of sites with and without existing load management practices and conducted a load-shifting optimization exercise to estimate potential cost savings and emissions reductions. This optimization analysis utilizes NSP data, where available, to assess charging flexibility for each site. For sites without sufficient NSP data reported, the analysis uses AMI data and a charging session availability template to assess charging flexibility. The analysis derives the template for each market sector based on the charging behavior of sites in that sector with NSP charging session data.

Load Management Outcomes Observed in EY2025

In EY2025 the Evaluation Team assessed 28 of the 35 operational PTD sites with AMI and NSP data that met the requirements for analysis. This included 12 school bus sites and 16 sites in other market sectors, including transit bus and medium-duty vehicle.

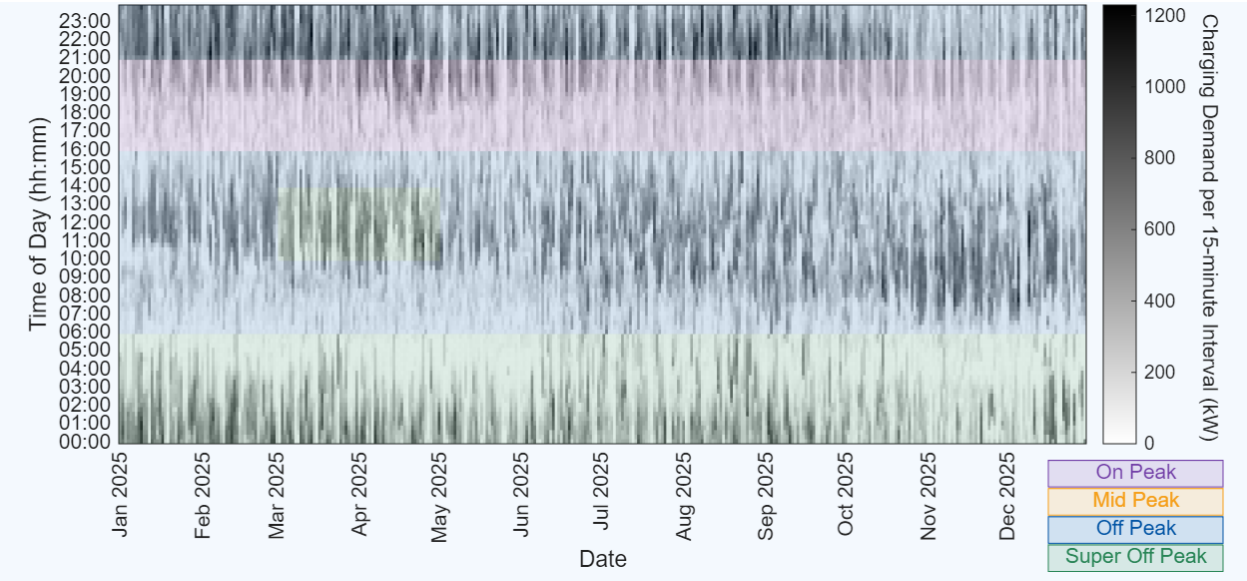
Figure 278 and Figure 279 depict the BAU historical energy consumption of school bus fleets and non-school bus fleets, respectively, in aggregate during 2025. BAU represents the current charging behavior of the 28 sites used for this analysis. The areas in the figures with darker shading correspond to times of day (y-axis) and days throughout the year (x-axis) with higher collective charging demand, as measured by the scale on the right of the plot. Areas with no shading represent no energy demand. The colored regions of the plot correspond to the Utility's TOU periods (on-peak, mid-peak, off-peak, and super-off-peak). School bus fleets (Figure 278) show a consistent trend of charging twice per day: once beginning around 9 a.m. after the morning routes to pick up students and again around 4 p.m. to 5 p.m. after buses complete afternoon runs. The second charging session directly coincides with higher TOU rates. Some sites using load management, however, are clearly delaying the second charging event until 9 p.m. to avoid peak TOU energy costs. The figure also clearly shows lower demand during winter break, spring break, and summer vacation periods when school bus operation is minimal. For comparison, Figure 279 presents the BAU charging demand for all other SDG&E fleets in non-school bus market sectors for 2025. This figure shows many fleets beginning to charge in the middle of the day, and some waiting until 9 p.m., with the vast majority of fleets demonstrating effective load management to avoid the higher-cost 4 p.m. to 9 p.m. time period.

Figure 278. SDG&E PYDFF Program Heatmap of the Collective BAU Charging Demand for All SDG&E School Bus Fleets in EY2025



Dark shading intensity indicates average charging demand (in kilowatts) per 15-minute interval. Colored regions indicate TOU periods.

Figure 279. SDG&E PYDFF Program Heatmap of the Collective BAU Charging Demand for All Non-School Bus SDG&E Fleets in EY2025

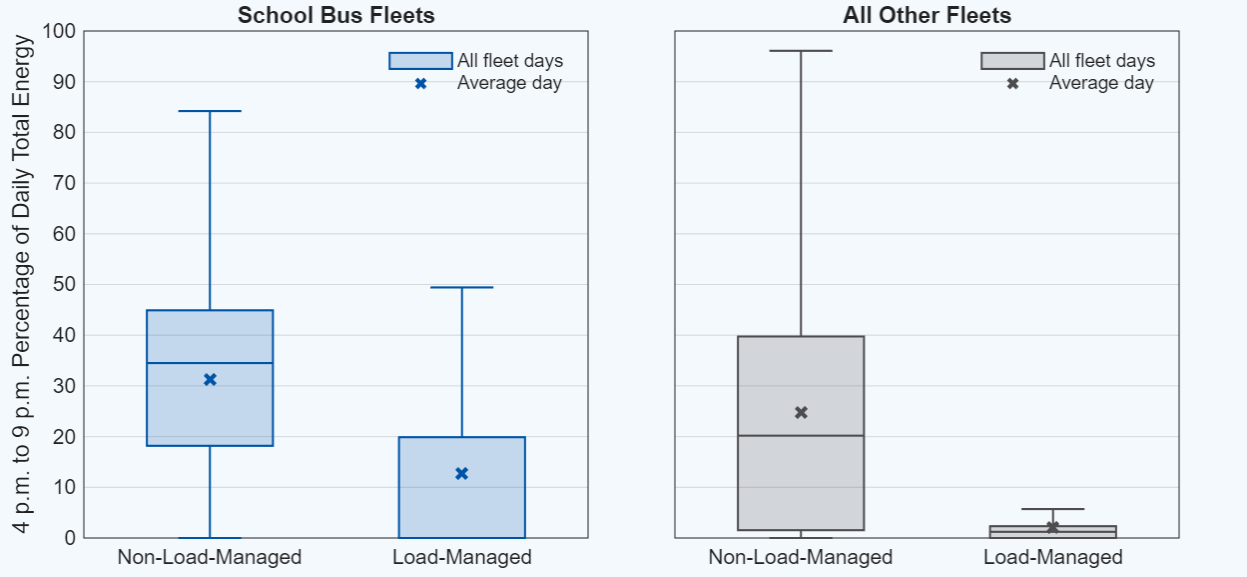


Dark shading intensity indicates average charging demand (in kilowatts) per 15-minute interval. Colored regions indicate TOU periods.

The Evaluation Team compared NSP charging sessions that utilized load management strategies with non-load-managed sessions for the school bus and non-school bus fleets to evaluate the effectiveness of the existing load management at minimizing energy during the 4 p.m. to 9 p.m. peak TOU period.

The box plots in Figure 280 compare the distributions of daily on-peak (4 p.m. to 9 p.m.) energy consumption, as a percentage of daily total energy, between load-managed and non-load-managed days. On average, non-load-managed school buses show 31.3% of daily consumption occurring between 4 p.m. and 9 p.m., with consumption as high as 84% for some days. For the average load-managed day, the percentage of charging in the lower-cost period drops significantly to 12.7% of overall consumption. For other market sectors (shown in the right subplot of Figure 280), the average non-load-managed day shows 25% of consumption during the peak TOU period, compared with a very low 2.1% for load-managed days. These comparisons help guide the Team's estimates of how much energy from non-load-managed days (and fleets) can shift to save money and emissions.

Figure 280. SDG&E PYDFF Program Distribution of the Fraction of Daily EV Charging Load Occurring in the Peak TOU Period



The box and whisker plot represents the distribution of daily total energy consumed from 4 p.m. to 9 p.m. across one operating day by group, and the average value for all operating days per group is indicated by an X.

This analysis strongly suggests that existing load management programs effectively reduce the fraction of energy consumed between 4 p.m. and 9 p.m. and thereby reduce energy consumption costs.

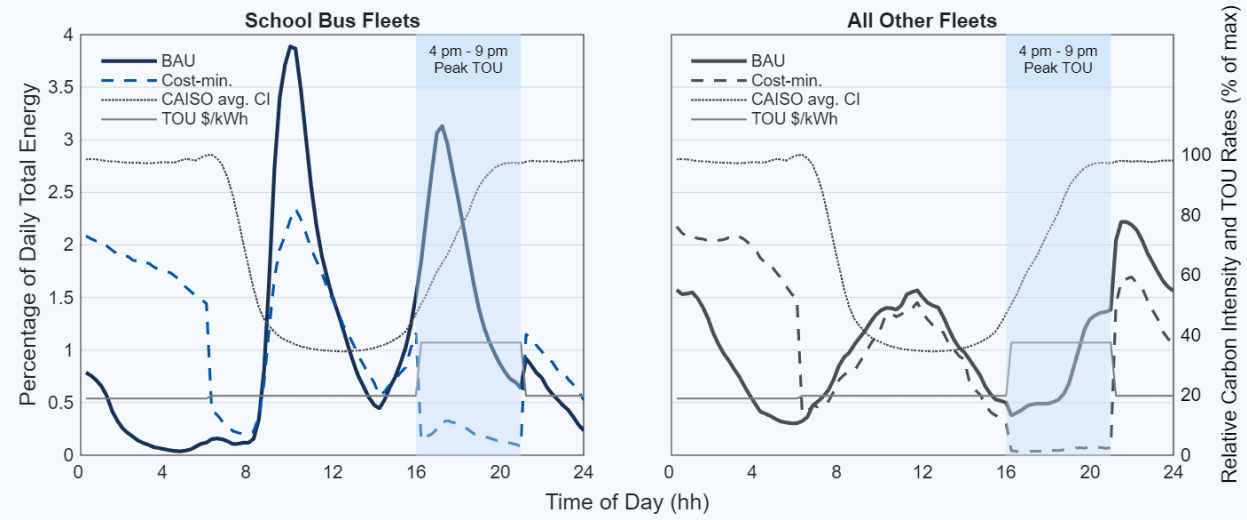
Potential Benefits of Optimal Load Management

The Evaluation Team analyzed charging session data to estimate the potential value of optimal load management, considering each site's observed operating patterns and ability to shift vehicle charging loads. This analysis included 12 school bus sites and eight sites in other market sectors that had sufficient AMI and NSP data reported for EY2025 to complete the optimization.

The Evaluation Team developed and executed an optimization routine that reviews each site's daily charging behavior and estimates the effect of shifting energy consumption from the peak time period (4 p.m. to 9 p.m.) to the lowest-cost periods of the day whenever there was both unused charging capacity and vehicle charging availability during those periods. The Evaluation Team used NSP charging session data to ascertain how many vehicles were plugged in and how many kilowatt-hours of energy could be shifted during each time period. For hours in the same TOU rate period, the Evaluation Team used carbon intensity of the electric grid (evaluated from CAISO 2025 GHG emissions factors) and BAU charging load as tiebreakers to determine vehicle charging priorities. The optimization algorithm also incorporates any monthly demand charges that may be incurred at the site from vehicle charging and minimizes the total charging costs. After completing the load shifting, the Team calculated costs and GHG emissions for the load-shifted case and compared the results with the BAU case to determine potential reductions in cost GHG emissions for each site.

Figure 281 illustrates how optimally shifted loads differ from BAU loads, averaged across EY2025. For both school bus and other market sector sites, the average day's load can be mostly shifted out of the high-cost 4 p.m. to 9 p.m. window (peak TOU period year-round). For school bus sites, midday charging is spread out over the available charging period—lowering the peak demand and reducing incurred demand costs—and the charging that occurs during the peak TOU period (4 p.m. to 9 p.m.) is redistributed to overnight charging, also reducing incurred TOU energy consumption and peak demand costs. For non-school bus sites, the load shifts to the overnight charging period, as these sites appear to have little flexibility to increase charging during the middle of the day (when the carbon intensity of the grid is lower), and the current TOU rate structure does not incentivize midday charging with lower TOU costs, thereby reducing potential GHG emissions reductions.

Figure 281. SDG&E PYDFF Program Fraction of Daily EV Charging Load Occurring at Each 15-Minute Interval for the Average Day in this Analysis, BAU Compared with Cost-Minimization



Line color indicates site market sector, and dashed versus solid lines indicate whether the load is BAU or shifted.

The Evaluation Team estimated the cost reduction potential of this daily load shifting. Results of the analysis should be viewed with the following context:

- This analysis considers the volumetric (cost per kilowatt-hour) component of each site's electricity costs as well as any demand charges that may apply under the utility's rate structure. Optimal load management has the potential to also reduce demand charge subscriptions, which could impact costs especially in lower-volume months. The cost-minimization approach developed in this analysis minimizes the monthly total cost (energy consumption plus demand charges). This allows for an increase in monthly peak demand so long as any applicable increased demand charges are more than offset by TOU cost savings resulting from load-shifting to less expensive TOU time periods. In most cases, monthly peak demand either stayed the same, having no impact on costs, or decreased, resulting in additional cost savings.
- These results reflect only the portion of the year in which each fleet operated vehicle chargers and provided charging data; annualized projections of these cost reductions could be substantially

higher, in absolute terms, for fleets that have less than a full year of charging data included in this analysis or that have not yet reached mature operations.

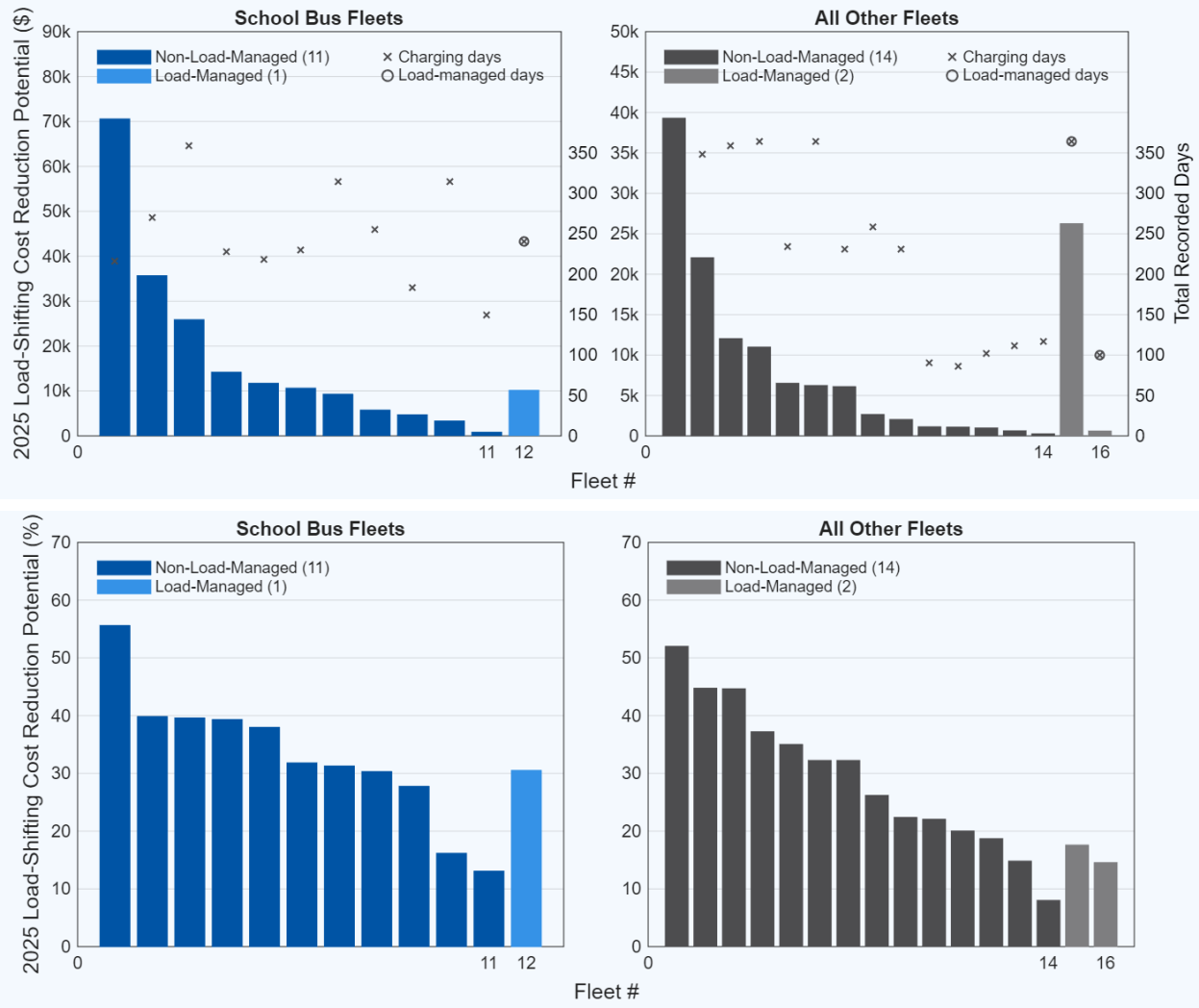
- These results reflect only the portion of each site's vehicle fleet that it electrified in EY2025. A fully electrified vehicle fleet would see higher cost reduction potential from load management.
- This analysis considers the cost-saving potential of load management, but it does not consider the potential of load management to generate revenue via LCFS Smart Charging credits.
- This analysis examined actual charging behavior at each site (using actual recorded plug-in and unplug times) to determine charging opportunities and does not account for other operational or scheduling improvements for charging electrified fleets, which could enable more-effective load management, resulting in higher potential cost reduction.

Although actual charging session data were used to inform this analysis, some operations and/or driving days do not allow for use of load management at some sites. When load management is possible and still not used by fleets, reasons include lack of clarity of actual versus potential electricity costs and concerns over vehicles not fully charging unless under the watchful eye of staff still on site. Starting to charge vehicles later in the evening when limited staff are available to check status could affect vehicle reliability and represents an operational risk.

Figure 282 provides several insights. The figure shows that even load-managed sites have the potential to save energy by better utilizing their load flexibility. For example, as shown on the top graph, sites that are already using load management have cost reduction potential ranging from approximately $10,000 in the school bus market sector and more than $25,000 for sites in other market sectors. In general, sites that are implementing load management have less opportunity to realize additional savings than sites that have not implemented load management to date. Many of these sites can capture additional savings by improving consistency of load management operations and better coordinating load management scheduling if their EVSP is capable and their operations allow.

Non-load-managed sites have a cost savings potential of up to $70,000 for school bus sites and up to nearly $40,000 for other market sectors. The greatest potential savings are typically seen at large sites with high energy consumption and therefore high overall costs. For example, as shown in the bottom graph, the load-managed fleet with $25,000 cost reduction potential is equivalent to a 15% overall costs savings, which is similar in magnitude to potential cost savings for many other fleets regardless of market sector or load management.

Figure 282. SDG&E PYDFF Program Total Annual Cost Reduction Potential of Each Site with Use of Optimal Load Management

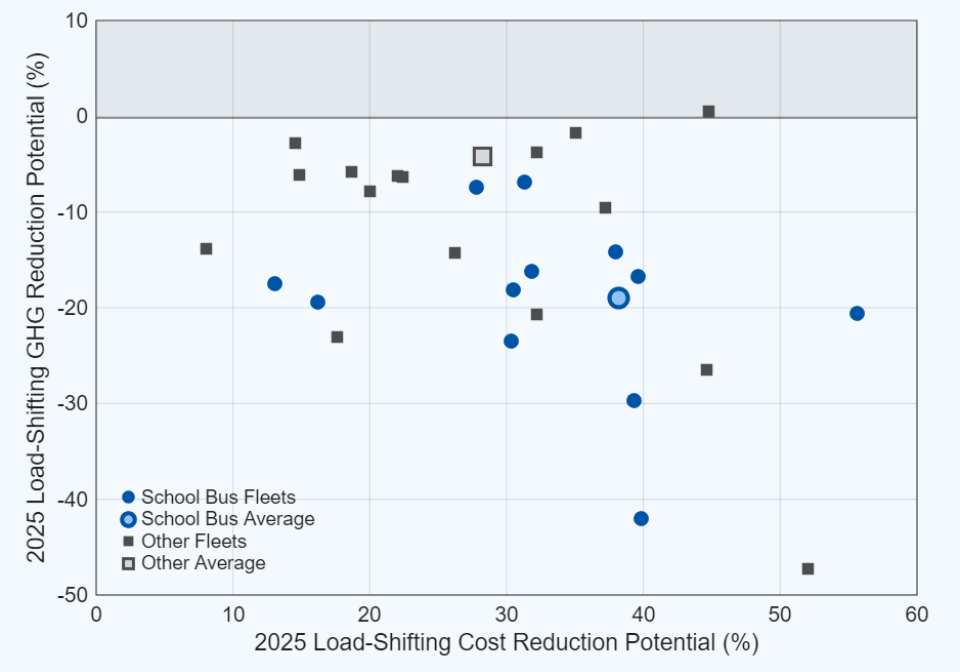


Each bar represents one site. Bar colors indicate the site's market sector, and bar shades show its use of load management.

Because lower-cost TOU periods often correspond to periods with lower carbon intensity for grid electricity, optimizing load management for energy cost savings can have a secondary effect of reducing the resulting carbon emissions from vehicle charging. Figure 283 shows estimated cost reductions and corresponding GHG emissions reductions for each site resulting from a cost-minimizing load management strategy (considering carbon intensity as a tiebreaking factor only when sufficient charging flexibility exists). Because the TOU rate structure slightly disincentivizes midday charging (the midday off-peak period is slightly higher than the super-off-peak period from midnight to 6 a.m.), the cost-minimization optimization seeks to redistribute charging load throughout the night, when possible, to minimize the peak charging load and thereby reduce incurred demand costs. However, this has the negative effect of reallocating charging to time periods with higher carbon intensity leading to potential

increases in GHG emissions (seen in the figure as negative values for GHG reduction potential). This issue primarily affects school bus sites rather than sites in other market sectors.

Figure 283. SDG&E PYDFF Program Potential Percentage Cost Reduction and Attributed GHG Emissions Reduction of Optimal Load Management and Cost Minimization



In addition to the cost-minimization load-shifting analysis, the Evaluation Team assessed the maximum achievable reduction in GHG emissions with load-shifting by rerunning the load-shifting optimization routine on the same data set to minimize GHG emissions at each site. This approach maximizes the amount of charging that can take place during the middle of the day when the carbon intensity of grid electricity is the lowest as long as additional charging capacity and vehicle charging availability exists at each site. Figure 284 shows how the average charging load profile for the GHG-minimization approach compares with the cost-minimization and BAU average load profiles. Figure 285 displays the resulting combination of cost-reduction and emissions reduction potentials for each site when load shifting is employed to minimize GHG emissions. There is clearly a tradeoff between minimizing costs and minimizing GHG emissions, as these figures show some instances of substantially higher GHG reduction potential at the expense of increased costs (seen in the figure as negative values for cost reduction potential). This is because more of the charging occurs during the midday off-peak period and during the high-cost peak period, the peak charging load is allowed to increase, or both. The results vary by site basis, and some sites may be able to effectively decrease both costs and GHG emissions with effective load management.

Figure 284. SDG&E PYDFF Program Fraction of Daily EV Charging Load Occurring at Each 15-Minute Interval for the Average Day in this Analysis, BAU Compared with Cost-Minimization and GHG-Minimization

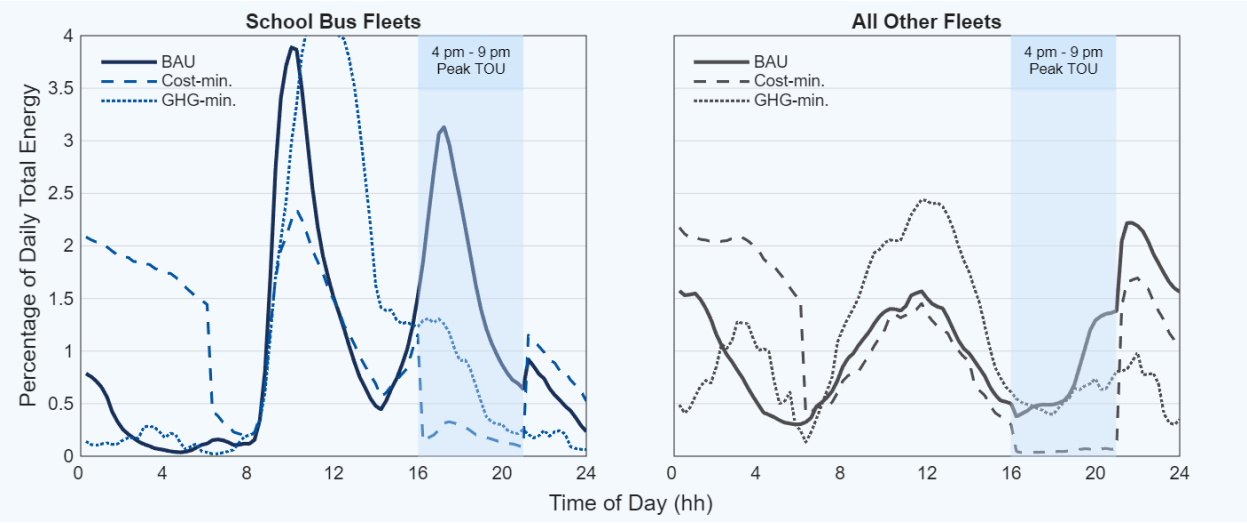


Figure 285. SDG&E PYDFF Program Potential Percentage Cost Reduction and Attributed GHG Emissions Reduction of Optimal Load Management, GHG-Minimization

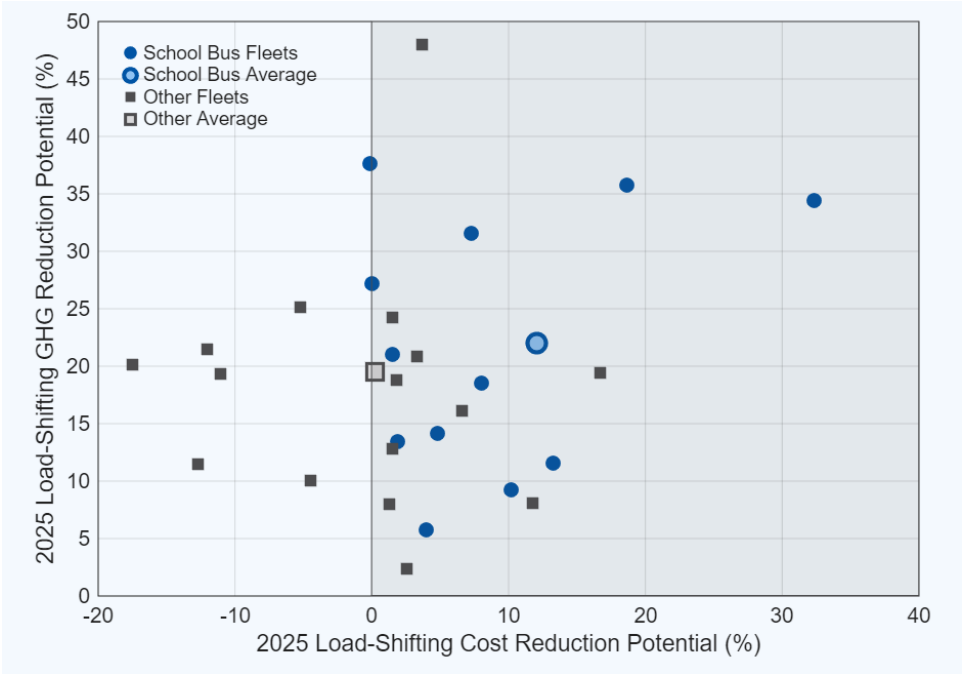


Table 110 aggregates these results across all sites included in the analysis. Overall, cost-minimization load shifting could reduce school bus sites' collective energy consumption costs by 38.2% but would lead to an increase of 18.9% in attributed electricity grid GHG emissions; for other market sectors, it could reduce energy consumption costs by 28.2% with a resulting increase of only 4.1% in attributed electricity grid GHG emissions. Alternatively, load shifting to minimize GHG emissions could significantly reduce

emissions but would come at the expense of slightly reduced cost savings. Across all school bus sites, load shifting to minimize GHG emissions could reduce GHG emissions by up to 22.0% with cost savings of 12.1%. Load shifting for GHG minimization at all other sites could reduce GHG emissions by 19.5% but would achieve virtually zero cost savings (0.3%).

Table 110. SDG&E PYDFF Program Summary of Potential Cost and Attributed GHG Emissions Reductions, Aggregated across All Included Fleets

	School Bus Fleets	All Other Fleets	All Fleets Combined
2025 Total Number of Fleets	**12**	**16**	**28**
2025 Total Operating Days	**2,978**	**3,694**	**6,672**
Cost-Minimization Load-Shifting			
Cost Reduction Potential ($)	202,726	138,871	341,597
GHG Reduction Potential (kg CO_2e)	-40,633	-11,401	-52,034
Cost Reduction Potential (%)	38.2%	28.2%	33.4%
GHG Reduction Potential (%)	-18.9%	-4.1%	-10.6%
GHG-Minimization Load-Shifting			
Cost Reduction Potential ($)	64,138	1,342	65,480
GHG Reduction Potential (kg CO_2e)	47,187	53,554	100,740
Cost Reduction Potential (%)	12.1%	0.3%	6.4%
GHG Reduction Potential (%)	22.0%	19.5%	20.6%

Highlights

- Charging data and anecdotal notes from operators indicate significant opportunity for most fleets to shift their charging energy use to lower-cost time periods depending on operating patterns, charging flexibility, and implementation of load management software.
- Many fleet operators are unfamiliar with their actual billing results, how their bills compare with best achievable energy costs, and how to implement load management.
- Sites from each evaluation year exhibit consumption growth for several years, highlighting how long it may take for fleets to fully mature EV operations.
- Overall demand in comparison peaked around 3.2 MW (double that of the previous year) compared with over 14 MW of capacity.
- Fewer sites in the PYDFF program (4; 10%) than in other Utility programs are using and show strong examples of load management such as through load curtailment during high-cost time periods.
- 15 of 28 sites with enough operational data show modeling results that indicate they had enough charging flexibility to save 30% or more on their annual electricity bills. Several other sites were between 20% and 30%.

Petroleum Displacement

The Evaluation Team estimated the petroleum displacement attributable to vehicle electrification enabled by SDG&E's PYDFF program. The Evaluation Team used DGE for reporting purposes. Since the transit bus sector primarily uses CNG fuel, the Team converted transit bus natural gas consumption to DGE units based on the CNG fuel's energy content.

Table 111 presents petroleum displacement impacts for the PYDFF Program through 2025, including estimated actual impacts for 2025, actual impacts for all PTD sites, and a 10-year forecast for PTD sites. The results include impacts for the five market sectors represented in the program, the majority of which were for the school bus sector, followed by the transit bus sector. The actual use in the program to date is over 6.12 million electric miles. This translates into the displacement of over 1.02 million DGE. Although the program classifies three sites as heavy-duty vehicle sites, one is a hybrid site with both medium-duty and heavy-duty vehicles in the VAP. Because all operational vehicles at this site in 2024 and 2025 were medium-duty vehicles, petroleum displacement and GHG reductions attributed to this site are included in the medium-duty vehicle market sector.

Table 111. SDG&E PYDFF Program Petroleum Displacement Summary

Market Sector	Usage (n=37)				Petroleum Displacement (DGE)		
	2025 Actual [a] kWh	PTD Actual [b] kWh	2025 Actual Use	PTD Actual Use	2025 Actual	PTD Actual	10-Year Projection
Airport GSE			47,723 hours	116,171 hours	91,150	221,887	599,051
Heavy-Duty Vehicle			6,698 miles	8,960 miles	869	1,089	44,411
Medium-Duty Vehicle			740,418 miles	1,191,166 miles	59,531	102,173	535,883
School Bus			1,463,216 miles	3,517,582 miles	160,467	385,934	1,527,830
Transit Bus			611,204 miles	1,304,266 miles	139,993	298,712	1,029,956
Truck Stop Electrification			64,730 miles	98,474 miles	9,522	14,467	79,753
Total			2,933,989 miles 47,723 hours	6,120,448 miles 116,171 hours	461,532	1,024,262	3,816,884

[a] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.

[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Highlights

- All operational sites in 2025 collectively achieved an impact of more than one million gallons of petroleum displaced in the program to date.
- The transit bus sector accounted for more than 139,000 gallons of displaced petroleum in EY2025 and is projected to account for 37% of the petroleum displaced over 10 years.
- Over a 10-year period, all operational sites will displace more than 3,800,000 gallons of petroleum.

Greenhouse Gas and Criteria Pollutant Impact

The Evaluation Team calculated reduced emissions from displaced fossil fuel use by ICE vehicles that were not in service because of the PYDFF program. First, the Team developed ICE counterfactual equivalents for each market sector, then calculated the emissions associated with these vehicles under conditions that otherwise matched the EVs, which provided a baseline. Although EVs have no tailpipe emissions, the electricity used to charge them comes from a mix of generation sources powering the electric grid,

including renewable and fossil fuels, with the latter primarily responsible for emitting GHGs and criteria pollutants into the atmosphere.

Table 112 shows GHG impacts from PYDFF for three time periods across market sectors: estimated reductions that reflect what program sites saved in 2025, PTD reductions from all sites, and a 10-year projection based on annualized data from all sites.

Table 112. SDG&E PYDFF Program GHG Reductions Summary

Market Sector	Usage (n=37)				GHG Reduction (MT)		
	2025 Actual [a] kWh	PTD Actual [b] kWh	2025 Actual Use	PTD Actual Use	2025 Actual	PTD Actual	10-Year Projection
Airport GSE			47,723 hours	116,171 hours	964	2,324	6,473
Heavy-Duty Vehicle			6,698 miles	8,960 miles	7	9	401
Medium-Duty Vehicle			740,418 miles	1,191,166 miles	465	757	4,403
School Bus			1,463,216 miles	3,517,582 miles	1,466	3,443	14,656
Transit Bus			611,204 miles	1,304,266 miles	1,039	2,179	7,994
Truck Stop Electrification			64,730 miles	98,474 miles	86	129	752
Total			2,886,266 miles 47,723 hours	6,120,448 miles 116,171 hours	4,027	8,840	34,679

[a] "2025 Actual" represents the data for EY2025 from all sites activated in the program to date.
[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Table 113 shows estimated reductions in local tailpipe emissions from ICE vehicles displaced by the PYDFF program. The transit bus sector shows the largest reduction in CO emissions because displaced buses are assumed to run on CNG. In addition, the Evaluation Team's analysis confirmed that airport GSE sites can achieve notable savings due to the poor emissions profile of conventional GSE.

Table 113. SDG&E PYDFF Program Local Emissions Reductions, PTD Actual Sites

Market Sector	PTD Actual [a] Sites (n=37)				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Airport GSE	318.9	347.0	319.3	385.9	13,966.0
Heavy-Duty Vehicle	-	0.1	0.1	0.2	2.2
Medium-Duty Vehicle	-	2.0	1.8	16.6	1,799.6
School Bus	-	8.1	7.8	36.0	1,021.6
Transit Bus	-	0.5	0.5	80.5	65,727.3
Truck Stop Electrification	-	1.7	1.6	4.7	60.6
Total	318.9	359.4	331.0	523.8	82,577.4

[a] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Table 114 shows the same information as Table 113 for 2025 actual. These are the localized emissions reductions that occurred based on actual PYDFF program operations this year.

Table 114. SDG&E PYDFF Program Local Emissions Reductions, 2025 Actual Sites

Market Sector	2025 Actual [a] (n=37)				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Airport GSE	142.9	146.1	134.4	172.9	5,820.7
Heavy-Duty Vehicle	-	0.0	0.0	0.1	1.9
Medium-Duty Vehicle	-	1.2	1.1	9.7	781.4
School Bus	-	3.4	3.3	15.2	428.6
Transit Bus	-	0.3	0.2	37.7	30,801.3
Truck Stop Electrification	-	1.1	1.1	3.2	40.8
Total	142.9	152.2	140.2	238.9	37,874.6

[a] "2025 Actual" represents the data for EY2025 from all sites activated in the program to date.

Table 115 provides an estimate of savings over the 10-year period. These are the annualized reductions from all sites to date extended over a decade. Again, the airport GSE sector shows very high reductions of all pollutants due to the poor emissions profile of off-road equipment. Transit buses show very high CO reductions but low PM reductions compared with CNG-powered buses.

Table 115. SDG&E PYDFF Program Local Emissions Reductions, 10-Year Projected Impact for PTD Sites

Market Sector	PTD Sites 10-Year Projected Impact (n=37)				
	HC (kg)	PM_{10} (kg)	$PM_{2.5}$ (kg)	ROG (kg)	CO (kg)
Airport GSE	1,285.2	1,048.2	964.3	1,555.1	40,644.0
Heavy-Duty Vehicle	-	3.8	3.6	11.3	144.8
Medium-Duty Vehicle	-	12.4	11.6	128.0	7,584.9
School Bus	-	36.5	35.0	158.5	4,332.0
Transit Bus	-	2.0	1.9	281.6	229,971.1
Truck Stop Electrification	-	12.0	11.5	31.4	409.5
Total	1,285.2	1,114.9	1,027.9	2,166.0	283,086.3

Table 116 shows counterfactual vehicle GHG emissions, emissions from the electricity used to charge the EVs, GHG emissions reductions, and percentage differences. Table 117 shows the net reductions of NO_X emissions from using EVs based on the counterfactual and Utility emissions. The Evaluation Team estimated a total annualized GHG emissions reduction of 80% for heavy-duty vehicles and 86% for medium-duty vehicles, and reductions of 73% and 81% in NO_X respectively from the use of heavy-duty vehicle and school bus EVs compared with counterfactual vehicles for sites completed in EY2025. Medium-duty vehicles did not show a reduction in NO_X, as the most common counterfactual was a gasoline pickup truck with relatively low NO_X emissions. Reviewing emissions reductions in the program to date reveals an estimated 86% actual reduction in both GHG and NO_X emissions.

Table 116. SDG&E PYDFF Program Counterfactual GHG Reductions

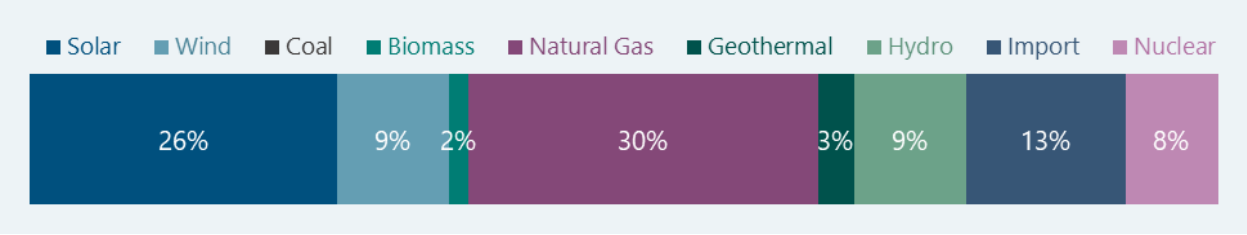
Market Sector	EY2025 Sites Annualized GHG (MT) (n=12)				PTD Sites GHG (MT) (n=37)			
	Counter factual	Utility	Reduction	% GHG Reduction	Counter factual	Utility	Reduction	% GHG Reduction
Airport GSE	–	–	–	–	2,485.1	161.5	2,323.6	94%
Heavy-Duty Vehicle	48.2	9.7	38.5	80%	11.5	2.3	9.3	80%
Medium-Duty Vehicle	80.4	11.5	68.9	86%	929.2	172.4	756.8	81%
School Bus	4,083.0	640.3	3,442.7	84%	4,083.0	640.3	3,442.7	84%
Transit Bus	2,628.3	449.5	2,178.9	83%	2,628.3	449.5	2,178.9	83%
Truck Stop Electrification	153.1	24.1	129.0	84%	153.1	24.1	129.0	84%
Total	888.8	118.4	770.4	87%	10,290.3	1,450.0	8,840.2	86%

Table 117. SDG&E PYDFF Program Counterfactual NO_X Reductions

Market Sector	EY2025 Sites Annualized NO_X (kg) (n=12)				PTD Sites NO_X (kg) (n=37)			
	Counter factual	Utility	Reduction	% NO_X Reduction	Counter factual	Utility	Reduction	% NO_X Reduction
Airport GSE	–	–	–	–	4,079.6	132.7	3,946.9	97%
Heavy-Duty Vehicle	28	8	21	73%	6.8	1.8	5.0	73%
Medium-Duty Vehicle	6	10	(4)	None	312.5	140.6	172.0	55%
School Bus	428	81	348	81%	3,612.4	533.2	3,079.1	85%
Transit Bus	–	–	–	–	126.1	367.1	(241.0)	None
Truck Stop Electrification	–	–	–	–	219.7	20.3	199.4	91%
Total	462.3	98.1	364.2	79%	8,357.2	1,195.7	7,161.5	86%

Figure 286 shows the annual program net electricity generation mix, matching the hours when the EVs were charging. The CAISO grid mix continually changes based on factors such as the level of total demand for power on the grid and the availability of fossil generation and variable renewable resources such as solar.

Figure 286. SDG&E PYDFF Program Net Electricity Mix, PTD Sites



At this stage of the program, it appears the vehicles were charging predominantly outside of peak hours of solar output when grid emissions were the lowest. More than 13% of the grid mix comprises electricity

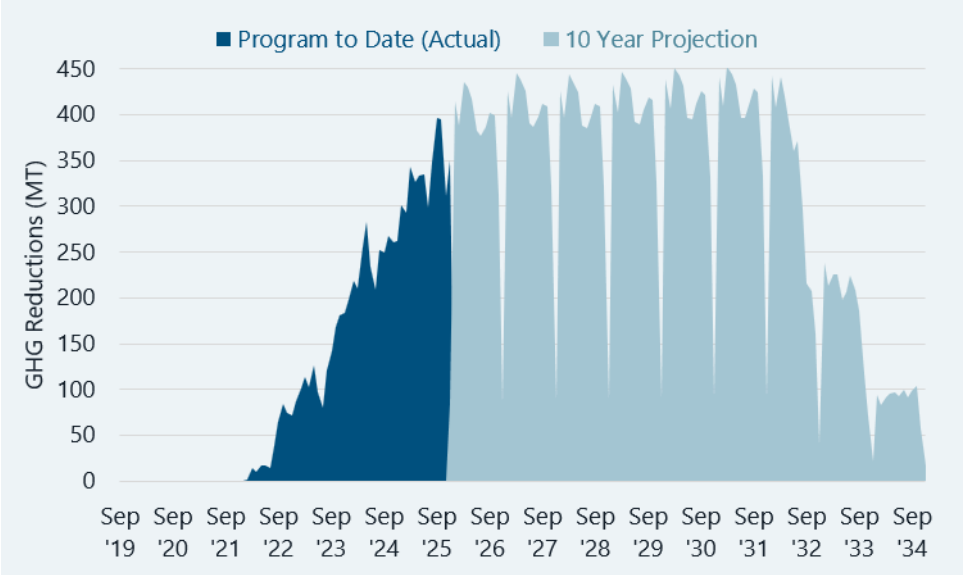
imports, which do not vary by time of day for analysis purposes but match the resource mix purchased for the California grid.[131]

Based on the real-time grid conditions at the time of charging, the overall energy mix was about 57% zero-emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 30% natural gas. The Evaluation Team expects emissions reductions from these sites over 10 years to increase as the grid becomes cleaner. Additionally, the increased use of managed charging, where possible, would reduce emissions as EVs charge at off-peak times and grid power is supplied with greater amounts of renewable generation. The *Electricity Cost and Emissions Optimization Analysis* in the *Grid Impacts* section above identified the potential for the fleet to further reduce GHG emissions by shifting the time and rate of charging. Finally, emissions will continue to decrease with the addition of more charging sites and EVs in future evaluation years.

Figure 287 shows how program GHG reductions have increased to date and are likely to grow over time for all active sites. The analysis period ranges from the activation date of the first site in the program through the end of EY2025. The analysis incorporates the net reduction (counterfactual emissions minus utility emissions) for each fleet within the SDG&E PYDFF program. Program-to-date emissions reductions appear in dark blue while anticipated benefits based on annualization appear in a lighter blue. As each site has its own starting date of operation, the 10-year sunset for each site appears as a gradual tapering off of program benefits between 2031 and 2034. This taper reflects that benefits are no longer counted after 10 years, although fleets will likely continue to use the infrastructure. While each year's operations appear similar, there are several key factors driving the variations, such as seasonality of utility generation sources (high utility emissions will appear as a dip on the curves), holidays occurring on weekends versus weekdays, and sites that became operational late in 2025 and will operate year-round in future years.

[131] The power associated with imports comes from a mixture of renewables, hydro, nuclear, and natural gas power plants located outside of California (www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation).

Figure 287. SDG&E PYDFF Program Historical and Forecasted GHG Reductions for PTD Sites



Highlights

- Results show an 86% reduction in GHGs and in NO_X emissions for the program to date.
- The greatest reduction in local emissions was for CO, with more than 37,500 kg in 2025 and a projected 10-year reduction of more than 283,000 kg.
- Based on the real-time grid conditions when EV charging occurred, the overall energy mix contained about 57% zero emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 30% natural gas.

Health Impacts

The Evaluation Team calculated public health impacts (as benefits and costs) of reductions in criteria pollutants from vehicle electrification. The pollutants included in the analysis are primary $PM_{2.5}$ and precursors of secondary $PM_{2.5}$, including NO_X, SO_2, NH_3, and VOCs. This analysis considered only tailpipe emissions reductions rather than full lifecycle emissions (such as power plant emissions). The Evaluation Team used the EPA COBRA to evaluate the health benefits associated with the emissions reductions. COBRA estimates the county-level monetized benefits for the county where emissions are reduced. The tool also estimates monetized benefits for all counties in the United States (since emissions disperse beyond the source county), although most impacts are felt in nearby counties, and the Team's analysis only examines California counties.

The morbidity-related monetary benefits include avoided lost wages, avoided medical costs, and the money people are willing to pay to avoid an illness or condition, such as a respiratory disease. The monetary benefits associated with mortality are measured by the value of a statistical life associated with premature mortality. COBRA reports both a low and a high impact for mortality, representing the uncertainties in the estimates.

The total value of the health benefits associated with emissions reductions from the PYDFF program for activated PTD sites is between $703,385 and $925,677. Table 118 shows the health benefits in California broken down by health endpoint.

Table 118. SDG&E PYDFF Program California Health Benefits for PTD Sites in 2025

Health Endpoint	Change in Incidence (Annual Cases)		Monetary Value (Annual, 2025 Dollars)	
	Low	High	Low	High
Mortality	**0.041**	**0.055**	**$609,898**	**$832,190**
Avoided Medical Care				
Hospitalization, Respiratory	0.005	0.005	$84	$84
Hospitalization, Cardiovascular	0.002	0.002	$61	$61
Hospitalization, Other	0.007	0.007	$163	$163
ER Visits, Respiratory	0.086	0.086	$143	$143
ER Visits, Cardiovascular	0.004	0.004	$9	$9
Out-of-Hospital Heart Attacks	< 0.000	< 0.000	$14	$14
Nonfatal Heart Attacks	0.009	0.009	$784	$784
Stroke	0.001	0.001	$58	$58
Lung Cancer	0.001	0.001	$49	$49
Asthma	49.918	49.918	$41,878	$41,878
Hay Fever	2.043	2.043	$2,345	$2,345
Lost Productivity				
Minor Restricted Activity Days	13.105	13.105	$1,697	$1,697
Work Loss Days	2.234	2.234	$728	$728
School Loss Days	25.996	25.996	$45,474	$45,474
Total Health Effects	-	-	$703,385	$925,677

At the site level, sites in the airport GSE market sector accounted for 61% of the monetary value from benefits, followed by the school bus (32%), medium-duty vehicle (3%), and TRE (2%) market sectors. Sites in the airport GSE and school bus market sectors cumulatively accounted for 93% of all benefits.

As part of this analysis, the Evaluation Team also examined health benefits within DACs, which may be disproportionately burdened by sources of pollution (including air pollution from ICE vehicles). Because COBRA estimates effects at only the county level, the Evaluation Team disaggregated health benefits by census tract using the relative population of each tract from the most recent ACS. For example, the Team allocated 10% of the value of the health benefits to a census tract with 10% of the county's population. The Evaluation Team then estimated the total benefits allocated to DACs and non-DACs.[132] This approach assumes that the benefits of emissions reductions are distributed evenly throughout the county. If the sites reside in DACs, and the emissions reductions are greater in the tracts near the sites, this approach

[132] DAC census tracts are defined as those included in the SB 535 Disadvantaged Communities List (2022), which includes DAC categories for CalEnviroScreen 4.0 Top 25%, CalEnviroScreen 4.0 High Pollution Burden Score and Low Population Count, and 2017 Disadvantaged Community (CalEnviroScreen 3.0 only).

understates the potential benefit to DACs. Additional information about emissions dispersion within counties would provide more precise estimates of health benefits to DACs and non-DACs.

In the Team's analysis, San Diego County had 55% of the total benefits, followed by Riverside County (20%), Los Angeles County (8%), Orange County (7%), and San Bernardino County (6%). Overall, 14% of the total benefits are in DACs.

Highlights

- Cumulative monetary health benefits for counties in California realized by PYDFF sites in terms of monetary benefits range from $703,385 for the low estimate and $925,677 for the high estimate.
- Sites in the airport GSE and school bus market sectors cumulatively accounted for 93% of all benefits.
- San Diego County had 55% of the total benefits, followed by Riverside County (20%), Los Angeles County (8%), Orange County (7%), and San Bernardino County (6%).
- Overall, 14% of the health benefits are in DACs.

Net Impacts

As part of the EY2025 net impacts analysis, the Evaluation Team planned to survey SDG&E participant fleet managers to estimate program effects on participants in order to exclude impacts from actions that participants would have taken without the program (freeridership) and to include any program-attributable indirect impacts on participants (participant spillover). Only one SDG&E participating fleet manager responded to the Evaluation Team's NTG questions in the EY2025 survey link that was provided during or following the site visits the Evaluation Team conducted. As a result, the Evaluation Team was unable to estimate a fleet manager-based NTG ratio from EY2025 primary research.

6.1.3. Lessons Learned

SDG&E staff continued to navigate changes in program participation driven by federal regulatory developments in 2025. As in prior years, regulatory uncertainty continued to shape customer decision-making and increased the level of support required from program staff. Several new developments added complexity to an already difficult operating environment.

- **Reduced regulatory incentives:** The withdrawal of the ACF waiver accelerated an existing decline in private-sector participation, as these customers were no longer required to electrify their fleets. In contrast, public-sector customers, including transit agencies still subject to state requirements, remained more actively engaged.
- **Tariffs and procurement uncertainty**: Federal tariff uncertainty further dampened program interest, particularly among customers in the United States–Mexico border region. In addition, supply chain delays remained a significant barrier, with customers continuing to face lead times of 14 to 18 months for equipment such as switchgear as in 2024.
- **Vendor instability:** Inconsistent vendor customer service for EVSE delivery, commissioning, and maintenance created additional obstacles. Staff turnover at vendor companies impacted communication and coordination. SDG&E staff remained limited in their ability to recommend specific vendors.

Through these changes, SDG&E staff helped customers understand and navigate new obligations and project risks that added complexity to program participation.

Building on lessons from previous years, SDG&E staff introduced changes to improve project follow-through and prepare for future infrastructure demand. One notable change was a new requirement for customers to sign participation agreements before SDG&E would remobilize resources after a project pause. Staff reported that this has helped ensure that Utility resources are directed toward projects that are more likely to reach completion. This adjustment was informed by a recurring issue from earlier program years, when customers often paused or withdrew before receiving their customer job package. In addition, in response to industrial growth in the Otay Mesa area, SDG&E created an internal cross-functional team to track demand, coordinate engineering resources, and support the infrastructure needed to serve emerging customers. These types of changes prepare staff to continue to support growing infrastructure demand.

The PYDFF program sites continue to help displace petroleum, reduce GHG and local emissions, and provide health impacts. The PYDFF PTD sites have displaced more than 1,000,000 gallons of petroleum in the program to date, with the school bus sector accounting for over 385,000 gallons. In addition, the PYDFF program has resulted in a reduction of nearly 9,000 MT of GHGs to date. PTD sites all positively contributed to lowering local emissions, with CO reduction being the most prominent, achieving a reduction of over 82,000 kg to date. Overall, 14% of the health benefits are in DACs, and the total monetized health benefits from sites range from $703,385 to $925,677.

Fleet managers remain motivated to participate in the program, experienced fewer cost concerns, and were satisfied with their overall experience. As in previous years, fleet managers said they were motivated to participate in the PYDFF program primarily by regulatory requirements and corporate/organizational sustainability goals or initiatives (two of three). Respondents reported two types of costs—charging infrastructure and vehicle purchase costs—as barriers before participation (one each), but did not cite infrastructure costs as a barrier after participation. Two of the three interviewed fleet managers indicated that they were *somewhat satisfied* with their overall program experience.

Average installed capacity per site, as well as average costs per site and per-kilowatt installed decreased. Average installed charging capacity per site through 2025 decreased to 349 kW compared with 383 kW through 2024. The average utility infrastructure cost, including TTM and BTM, was $401,565 per site through 2025, lower than costs of $455,777 per site through 2024. The average Utility infrastructure cost was $37,513 per vehicle and $1,951 per kilowatt through 2025, compared with $24,262 per vehicle and $2,135 per kilowatt through 2024. All-in costs paid by the customer and SDG&E varied widely between sites, with an average of $735,949 in the program to date, a significant decrease from $890,741 through 2024.

Overall site activation timelines increased significantly from those in prior evaluation years as larger sites came online. The overall median number of calendar days from application to activation was 1,137 days in EY2025, compared with 1,106 days in EY2024, and 871 in the program to date. This was driven by the average installed capacity per site almost tripling between EY2024 and EY2025. Additionally, now that PYDFF is in the second half of its intended operating period, sites with longer lead times are

coming online, whereas in early years of the program sites with shorter lead times were activated. Contract issuance is now the longest program phase, reaching 441 days in EY2025, compared with 118 days in the program to date. Design and permitting continues to account for a large portion of site activation timelines, averaging 292 days in EY2025 and 270 in the program to date.

The PYDFF program lags its activated site and vehicle deployment goals, and program spending remains low; however, the program has met its DAC targets. In EY2025, 12 sites with 175 charging ports were activated supporting 237 vehicles, based on VAPs of activated sites. Six market sectors participate in the program; medium-duty vehicle sites continue to be the most common, representing 49% of all sites (18), followed by school bus sites at 35%. The 62 contracts signed in the program to date satisfies 21% of the program's per se reasonableness goal of 300 signed contracts. These sites would support 1,451 MDHD vehicles, which would meet 48% of the program's per se reasonableness goal of 3,000 vehicles. However, while the per se reasonableness goals in the CPUC Decision results in a ratio of 10 MDHD EVs per site (3,000 divided by 300), the ratio in the program to date is 25 MDHD EVs per site, which is more than twice this ratio.

SDG&E spent $7.9 million of the PYDFF program budget in EY2025, bringing total spending to $32.4 million of the $107.4 million approved program budget, or 30% of available funding. The total spending does not include funding reserved for contracted sites that have not yet been fully financially closed out. The cumulative percentage of spending in DACs sites is 50%, which exceeds the program's per se reasonableness goal of 30%.

Though overall consumption increased significantly, peak demand represents a small portion of installed charging capacity. Over 6 MW of new charging capacity was activated in the PYDFF program in EY2025, bringing total capacity for PTD sites to more than 15 MW. Overall consumption in EY2025 was over 4.5 MWh, an increase of 39% from more than 3 MWh in EY2024. Peak demand reached 3.2 MW in EY2025, a 78% increase over a peak of 1.8 MW in EY2024, and on-peak total utilization increased from 17.8% of all energy consumed in EY2024 to 20% of all energy consumed in EY2025, similar to 19% for the program to date.

Very few fleets are using load management, and fleets have significant opportunities to reduce costs and GHG emissions. Only three of 37 of the operational sites in the PYDFF program exhibit use of load management, which is lower than rates in other Utility programs. On a monthly basis, 48% school bus charging, 32% of transit bus charging, and 17% of medium-duty vehicle charging sessions have enough flexibility to be shifted to lower-cost and lower-emissions time periods, with nearly half of sites having enough flexibility to save 30% or more on their monthly utility bills. Notably, 38% of all school bus charging sessions have enough flexibility to shift all on-peak charging to off-peak periods without impacting operations. Potential savings through use of load management are as high as $70,000 per site annually for non-load-managed sites, and $25,000 for sites already using load management through optimization. On average, sites can reduce GHG emissions by more than 20% by optimizing charging through load management.

Not all NSPs offer load management capability and only two of 10 NSPs operating in the PYDFF program have customers that consistently use load management. Most fleet operators were aware of TOU pricing,

but not all fleet operators have direct access to their utility bills to understand TOU cost impacts. During site visits and deep dive interviews it was observed that most operators expected their average electricity costs to be lower than the actual cost data presented by the Evaluation Team.

Across more than 500 billing months for PYDFF program sites, the lowest average monthly electricity costs are approximately $0.20/kWh through use of load management, and 17% of monthly billing has an average cost below $0.30/kWh. However, 25% of sites have billing months with costs greater than $1.00/kWh. though most of these high energy-cost billing months are from sites with very low usage for which monthly fees were spread across a small number of kilowatt-hours. Overall, larger sites tend to have lower per-kilowatt electricity costs, both because these sites are more likely to use load management and because monthly fees are spread across a larger number of kilowatt-hours.

6.2. Schools and Parks Pilots

6.2.1. Overview

This overview provides a detailed description of the SDG&E Schools and Parks Pilots; summaries of the Pilot implementation process, performance metrics, program materials, and budgets; and a timeline of major milestones. Following the overview are detailed findings, highlights, and lessons learned.

Pilot Description

Schools Pilot: Through its Schools Pilot, SDG&E has offered direct installation of and incentives for installing 184 L2 chargers and 12 DCFCs at 30 schools and educational institutions.[133] SDG&E is aiming for 40% of installations to be within DACs.[134] The Pilot has a turnkey ownership model, with which SDG&E offers to install, own, operate, and maintain the EVSE. The charging stations are required to use TOU rate pricing. Site hosts who opt to own the chargers are eligible for a rebate equivalent to the cost that SDG&E would pay to install EVSE under the SDG&E turnkey model.

Schools Pilot Targets

- 184 L2 and 12 DCFC ports
- 30 schools
- 40% in DAC locations

Schools Pilot Design Goal

Empower schools to offer public charging to staff, students, parents and the greater community.

Parks Pilot: Through its Parks Pilot, SDG&E will aim to install 74 light-duty public chargers in 12 state parks and beaches within its service territory and 66 light-duty public chargers at 10 city and county park sites. SDG&E will build, own, operate, and maintain the EVSE, which will use a TOU rate. SDG&E developed an awareness campaign to inform the public of the availability of these chargers.

Parks Pilot Targets

- 74 charging ports at 12 state parks and beaches
- 66 charging ports at 10 city and county parks
- 50% in DAC locations

Parks Pilot Design Goal

Encourage parks and beaches to charge their own fleets and offer charging to staff and patrons.

Implementation

As interested customers became aware of the Schools Pilot, through SDG&E marketing efforts, word of mouth, or from an account manager from SDG&E, they could submit an application as the first step in the implementation process. For the Parks pilot, SDG&E identified eligible sites and reached out directly to

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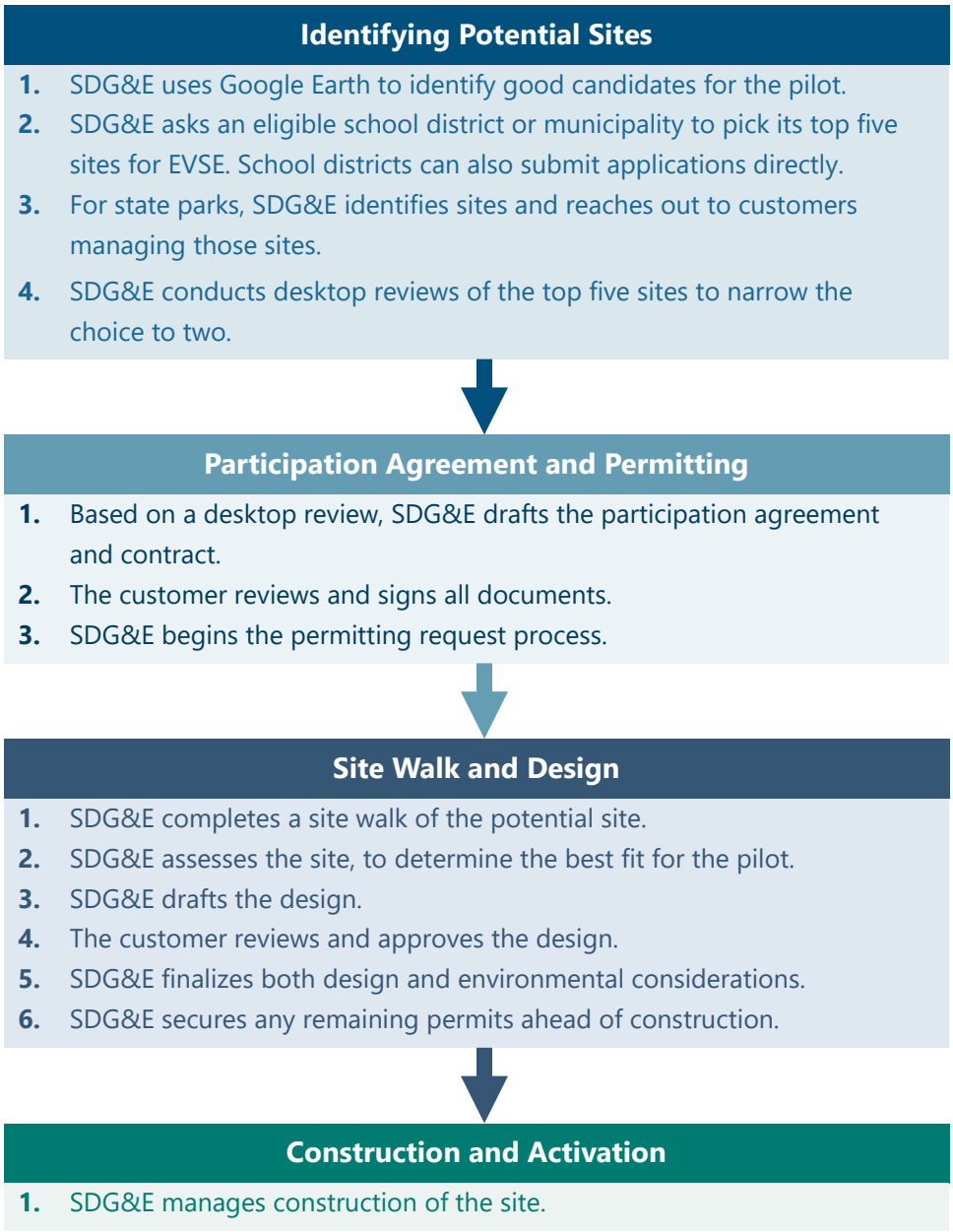
[133] In the EY2024 closeout interviews, SDG&E staff reported that they will not achieve the 30-site goal; however, they are installing more ports than expected and will still reach the port goal (which is the primary goal for the program), so they have not made a formal regulatory filing to change the Schools Pilot goals.

[134] As per AL 2876-E, SDG&E found that only 27 census tracts in its territory were considered DACs (using the top quartile in CalEnviroScreen statewide definition). However, the service territory definition produces a broader definition and leads to a calculated 180 DAC census tracts in SDG&E service territory.

the customers managing those sites. Starting in 2022 and continuing through 2025, SDG&E staff were focused on implementing the pilots.

Figure 288 shows the implementation process for the Schools and Parks Pilots. The customer agreement step is slightly different for state parks, municipal parks, and schools in the Schools Pilot, because the DPR expects to approve the MPA that will apply to all state parks in SDG&E service territory that participate in the Parks Pilot. Each individual Parks Pilot site will have site addendums to the MPA based on specific site needs and designs.

Figure 288. SDG&E Schools and Parks Pilots Implementation Process



Program Performance Metrics

The Evaluation team reviewed sites participating in the SDG&E Schools and Parks Pilots and analyzed them by status. Table 119 and Table 120 provide the count of sites by completion status in SDG&E's Schools Pilot and Parks Pilot, respectively, in EY2025 and for the pilot to date.

Table 119. SDG&E Schools Pilot Complete Site Count by Status

Site Status	EY2025	Pilot to Date
Utility Construction Complete	7	26
Activated	7	26
Operational	7	25
Closed Out	5	22

Table 120. SDG&E Parks Pilot Complete Site Count by Status

Site Status	EY2025	Pilot to Date
Utility Construction Complete	0	11
Activated	0	11
Operational	0	11
Closed Out	0	11

In EY2025, SDG&E Schools Pilot completed construction and activated seven sites. SDG&E Parks Pilot did not complete construction or activate any sites in EY2025. Neither pilot signed any additional contracts in EY2025, so the Schools Pilot has a total number of 26 contracts signed to date and 11 for the Parks Pilot.

Table 121 presents site-level data by each pilot, showing DAC status and number of ports for the sites activated in EY2025 and for the pilots to date. The cumulative percentage of DAC sites in the Schools Pilot is 50%, which exceeds the Pilot's per se reasonableness DAC metric of 40%. The Schools Pilot deployed an additional 55 L2 charging ports in EY2025, bringing the total number of ports installed in the pilot to date to 229 (222 L2, 7 DCFC).

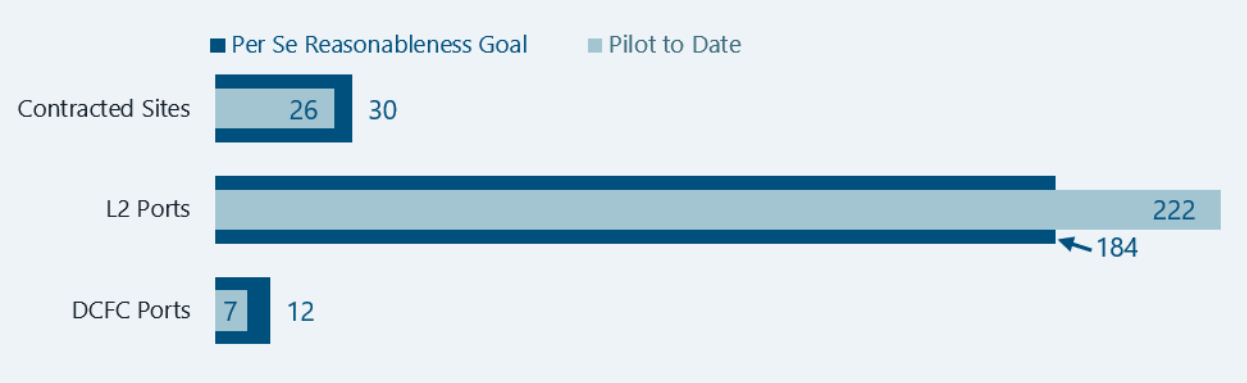
As displayed in Table 121, the Parks Pilot did not install any new ports in EY2025, keeping the total number of charging ports installed in the pilot to date at 90 (82 L2, 8 DCFC). No SDG&E Parks Pilot sites were activated in EY2025; 91% of sites to date remain located in DACs. The only Parks Pilot site outside of a DAC is located on Tribal land. The SDG&E Parks Pilot has separate per se reasonableness DAC goals for charging sites located in city or county parks (100%) versus state parks or beaches (50%).

Table 121. SDG&E Schools and Parks Pilots Activated Site Data in EY2025 and Pilot to Date

Pilot	EY2025				Pilot to Date			
	Activated Sites Inside DAC	Activated Sites Outside DAC	L2 Ports	DCFC Ports	Activated Sites Inside DAC	Activated Sites Outside DAC	L2 Ports	DCFC Ports
Schools	3	4	55	-	13	13	222	7
Parks	-	-	-	-	10	1	82	8

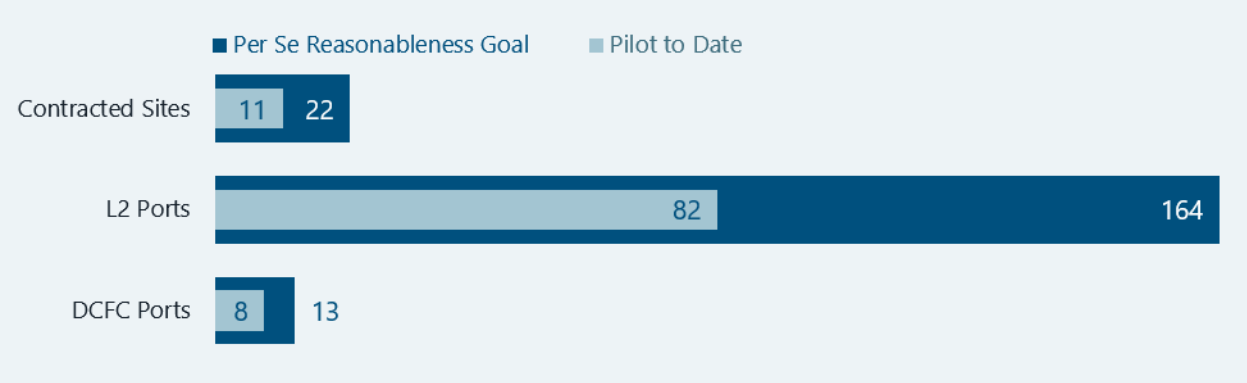
As shown in Figure 289, the 26 contracts signed in the program to date meet 86% of the pilot's per se reasonableness goal of 30 sites. All contracted sites have been activated. There are 222 L2 ports installed at the 26 sites, which exceeds 100% of the pilot's per se reasonableness goal of 184 L2 charging ports. There are seven DCFC ports installed at the 26 activated sites, which meet 58% of the Pilot's per se reasonableness goal of 12 DCFC charging ports.

Figure 289. SDG&E Schools Pilot Site and Port Per Se Reasonableness Goal Progress



As displayed in Figure 290, the 11 contracts signed in the program to date meet 50% of the Pilot's per se reasonableness goal of 22 sites. All contracted sites have been activated. The sites support 82 L2 ports, which meet 50% of the Pilot's per se reasonableness goal of 164 L2 charging ports. There are eight DCFC ports installed at the activated sites, which meet 62% of the Pilot's per se reasonableness goal of 13 DCFC charging ports.[135]

Figure 290. SDG&E Parks Pilot Site and Port Per Se Reasonableness Goal Progress



The CPUC established six phases in the program timeline per the SB 350 reporting template. Table 122 shows the median durations by program phase for EY2025 and pilot-to-date activated sites in the SDG&E

[135] DCFCs are limited to colleges and universities.

Schools Pilot.[136] In EY2025, the median number of calendar days by phase for the Schools Pilot ranged from two days for Application Review to 643 days for Design and Permitting. Median durations for the Contract Issuance, Design and Permitting, and Construction Complete phases were significantly longer in EY2025 than in the pilot to date. In total, sites activated in EY2025 took a median of 1,532 days from the Application Review phase through Activation, compared with 974 in the pilot to date. The *Site Visit Findings* section below describes possible causes of the long activation timelines, including delays in the NSP commissioning process.

Table 122. SDG&E Schools Pilot Median Calendar Days per Phase

CPUC Program Phase	Median Calendar Days	
	EY2025 [a]	Pilot to Date [b]
Application Review	2	3
Site Assessment	36	70
Contract Issuance	372	250
Design and Permitting	654	378
Construction Complete	269	108
Activation	16	5

[a] "EY2025" represents the data for the sites activated in 2025.

[b] "Pilot to Date" represents the data from all activated sites from program inception for all program years.

Table 123 shows the median durations by program phase for pilot-to-date activated sites in the SDG&E Parks Pilot, as there were no new sites in the pilot for EY2025.

Table 123. SDG&E Parks Pilot Median Calendar Days per Phase

CPUC Program Phase	Median Calendar Days	
	EY2025 [a]	Pilot to Date [b]
Application Review	-	1
Site Assessment	-	1
Contract Issuance	-	255
Design and Permitting	-	201
Construction Complete	-	77
Activation	-	8

[a] "EY2025" represents the data for the sites activated in 2025.

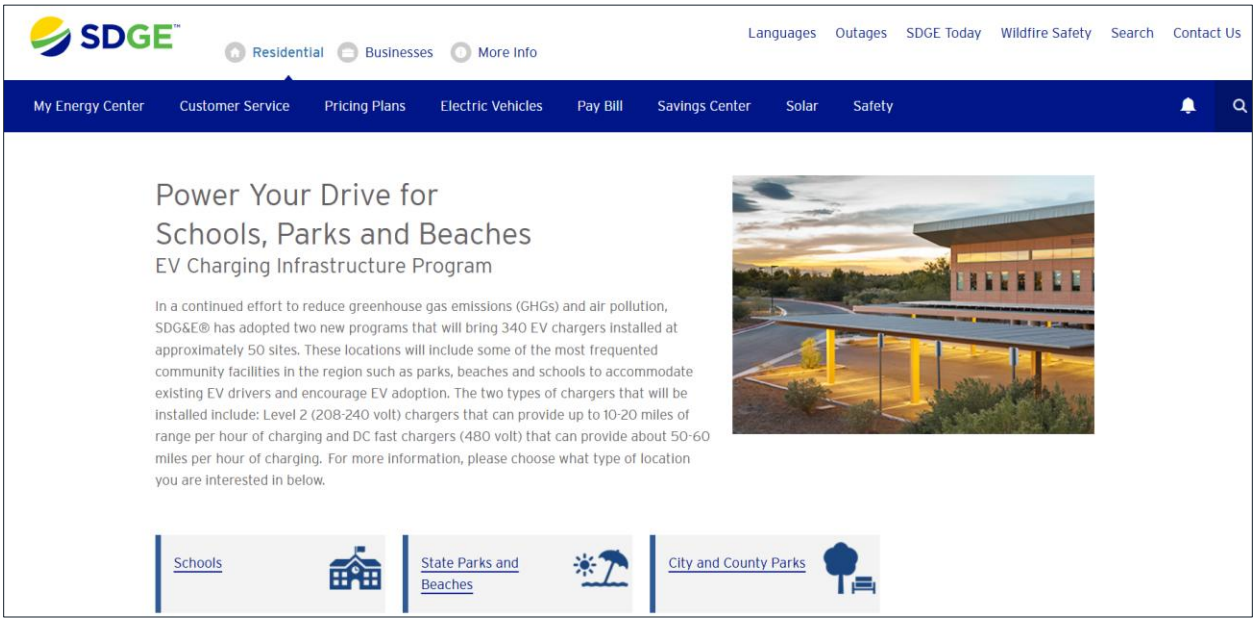
[b] "Pilot to Date" represents the data from all activated sites from program inception for all program years.

[136] For EY2025, SDG&E updated its method for mapping its internal application milestones to CPUC Program Phases. As a result, EY2025 and program-to-date median durations for the SDG&E Schools Pilot and Parks Pilot cannot be compared with durations included in previous evaluation reports.

Program Materials Summary

Schools Pilot and Parks Pilot: SDG&E maintains dedicated webpages with information on the pilots, including program highlights, equipment ownership options, and program eligibility requirements. In 2025, SDG&E reported a total of 34 visitors and 307 page views for the Power Your Drive for Schools, Parks and Beaches Pilot landing page. The Schools Pilot webpage had 99 visitors and 281 page views. As shown in Figure 291, the State Parks and Beaches Pilot webpage had seven visitors and 61 page views, while the City and County Parks Pilot webpage had 14 visitors and 76 page views.

Figure 291. SDG&E Program for Schools, Parks and Beaches Website Homepage



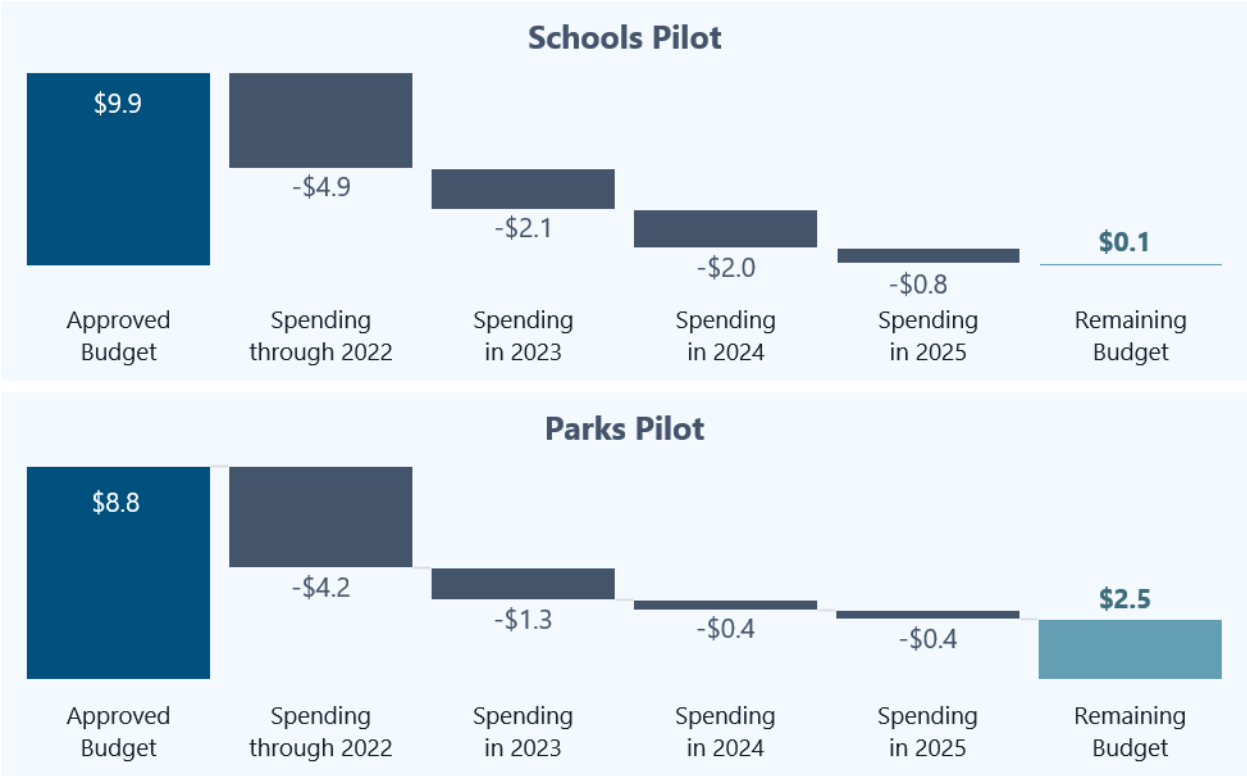
Schools Pilot: In EY2025, SDG&E focused on constructing new sites and developing new sites operated by existing customers, rather than recruiting new participants. As a result, the majority of marketing activities occurred in EY2023, with no new initiatives in EY2024 and EY2025. In 2025, SDG&E continued to distribute the children's book that had previously been developed to schools that requested it.

Parks Pilot: The primary marketing activity for the Parks Pilot was the #LOVEELECTRIC campaign, which was more limited in EY2025 than in previous evaluation years due to program enrollment closing as projects were already established. At the end of 2025, SDG&E staff began planning marketing activities for State Parks sites in 2026, which may include a ribbon-cutting ceremony and a video campaign.

Budget Summary

As shown in Figure 292, from inception through the end of 2025, SDG&E spent $9.8 million of the $9.9 million approved budget for the Schools Pilot and $6.3 million of the $8.8 million approved budget for the Parks Pilot. Parks Pilot spending continues to be lower than expected because the primary activities have focused on negotiations with the DPR, site planning for state park sites, and ongoing maintenance for established local municipal parks sites.

Figure 292. SDG&E Schools and Parks Pilots Budget (Millions USD) as of December 31, 2025



Timeline

Since the launch of the Schools and Parks Pilots, SDG&E has filed several Advice Letters to propose program changes, report progress, and meet regulatory requirements. On January 6, 2020, SDG&E filed AL 3490-E proposing updates to the Schools Pilot, including the ability for Schools Pilot sites to choose between utility- and site-owned EVSE, with utility provided rebates to make the two options for site ownership financially comparable. In June 2020 SDG&E filed AL 3551-E, which outlined specific rebate amounts for EVSE equipment, maintenance, and network fees and complies with Decision 19-11-017.

In February 2020, SDG&E and the joint Utilities filed AL 3504-E, seeking CPUC approval for a survey designed to measure EV adoption at Schools Pilot sites among faculty, parents, and students.

On April 23, 2021, SDG&E filed AL 3748-E, requesting to expand the statewide definition of DACs in the service territory to match SDG&E's DAC definition. The CPUC approved this filing in May 2021.

In June 2021, SDG&E filed AL 3781-E to confirm its plan to install DCFCs across state, city, and county parks. The filing included signed site designs for three parks, confirming host approval for DCFC installation. SDG&E had selected these sites based on features that support shorter dwell times, such as freeway access and multiuse amenities. The filing also met CPUC requirements by documenting site host approval and summarizing the design options presented. In October 2021, SDG&E filed AL 3864-E to confirm its plan to install DCFCs at three educational institutions as part of the Schools Pilot. The filing included signed designs confirming host approval. SDG&E had selected these locations based on

commuter-focused use and freeway access. The filing also satisfied CPUC requirements by documenting site host approval and summarizing design options. Although these early filings established the foundation for implementation, staff faced challenges related to construction costs, permitting, and timelines.

Toward the end of 2021, SDG&E filed two key updates. On November 8, the Joint Utilities filed AL 3890-E providing a status update on implementation. The filing confirmed that the Parks Pilot had launched on April 8, 2021, and that the Schools Pilot had launched in October 2021, with the first site beginning construction on October 25, 2021. On November 30, SDG&E filed AL 3902-E, which included an attestation confirming compliance with safety requirements for both pilots. The filing verified that all installed EV infrastructure met federal, state, and local safety standards, as required by Decision 19-11-017.

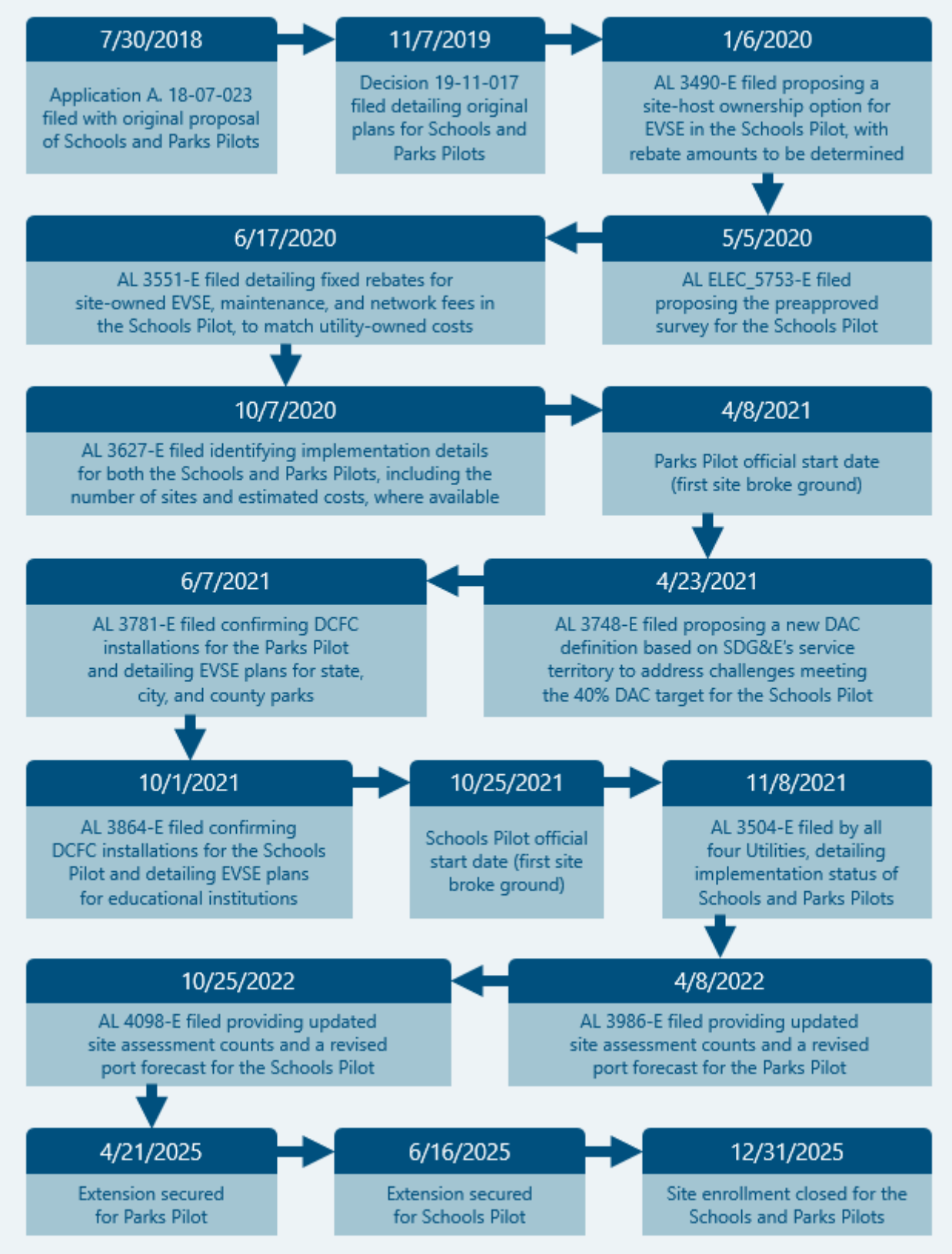
In April 2022, SDG&E filed AL 3985-E, reporting on efforts to deploy the pilots in Tribal communities. The filing detailed interest from two Tribal Nations and confirmed that one had submitted a complete participation package for the Parks Pilot.

SDG&E did not achieve any major milestones or submit any filings in 2024 and focused on securing a MPA and constructing sites. In April 2025, SDG&E secured the State Parks MPA for the Parks Pilot.

In addition, though it did not file a formal Advice Letter, SDG&E submitted a request through Rule 16.6 to extend program enrollment through December 31, 2025, for both the Schools and Parks Pilots. The extensions were approved in June 2025 for the Schools Pilot and April 2025 for the Parks Pilot.

Figure 293 shows all major milestones since the beginning of the pilots.

Figure 293. SDG&E Schools and Parks Pilots Key Milestones



6.2.2. Findings

This section provides findings from analyses of incremental EV adoptions, site visits and site costs, grid impacts, petroleum displacement, GHG and criteria pollutant reductions, and health impacts, as well as insights from Utility staff interviews.

Table 124 summarizes key impact parameters for EY2025 as well as for the program to date. Annual estimates of impacts are provided for metrics calculated as part of the impact evaluation. The table also provides estimates of impacts across all sites included in the program population through the end of 2025.

Table 124. SDG&E Schools and Parks Pilots Impacts Summary

Impact Parameter	EY2025 Sites [a]	EY2025 Sites Percentage in DAC	PTD Sites Actual	PTD Sites Actual Percentage in DAC
Population of Activated Sites	7	43%	37	62%
Sites included in analysis	7	43%	37	62%
Charging Ports Installed	55	38%	319	58%
Electric Energy Consumption (MWh)	143	46%	2,853	68%
Petroleum Displacement (GGE)	8,992	46%	229,561	70%
GHG Emissions Reduction (MT) [b]	79.9	47%	1,838	69%
PM_{10} Reduction (kg)	0.44	46%	9.09	68%
$PM_{2.5}$ Reduction (kg)	0.41	46%	8.36	68%
ROG Reduction (kg)	4.48	46%	156.10	71%
CO Reduction (kg)	192	46%	5,274	70%

[a] Energy consumption, petroleum displacement, and emissions reductions are based on annualized data. Pilot-to-date results are based on actual data (see *Appendix B* for details).

[b] GHGs include CO_2, CH_4, and N_2O multiplied by their respective GWP as defined by IPCC AR5 (see *Appendix B* for details).

Incremental EV Adoption

There are two main channels through which the availability of public charging networks may affect EV purchases. The first is a network effect, through which EV owners gain increased access to the public charging stations because of the stations' placement at destinations such as workplaces, commercial establishments, schools, and parks. The Evaluation Team expects the availability of EV charging equipment at convenient locations (for midday charging away from home) to increase the convenience of owning an EV (such as by lessening range anxiety) and to increase the probability of EV ownership. The second channel is a neighborhood effect on the driving population living in areas neighboring the public EV charging stations. The Evaluation Team expects the availability of nearby charging infrastructure to reduce the cost of EV ownership by providing alternatives to home charging. The Evaluation Team expects that public EV charging will have the biggest impact on residents of multifamily buildings, many of whom will have limited access to EV charging equipment, or on low-income households, which may be unable to afford home EV charging equipment. Public charging access may boost EV ownership through both channels and there may be positive interactive effects between the channels that boost the overall impact

of public charging networks. The Evaluation Team focused on analyzing the second channel and will analyze the impacts for the first channel separately when data become available.

The Evaluation Team estimated the effect of the public charging stations on household EV adoption for neighboring populations with a two-state analysis. In Stage 1, the Team looked at historical impacts of public EV charging on vehicle ownership. See *Appendix B* for the details of Stage 1 analysis. Using the impact estimates from the Stage 1 analysis,[137] the Evaluation Team estimated the impact of SDG&E investments in public charging on EV ownership for Stage 2. By the end of 2025, 26 charging stations in SDG&E's Schools Pilot and 11 charging stations in its Parks Pilot had been activated. The Team estimated the impact of these stations based on annual EV registrations as well as cumulative EV registrations driven by the Schools Pilot through the end of 2025.

SDG&E Schools Pilot

Based on the composite measure of public charging access, the Evaluation Team calculated the change in access to public charging due to SDG&E's Schools Pilot investment for each CBG where the investments affected access. Table 125 shows that the average change in access across all affected CBGs from pilot sites through 2025 was 13, and the average change in the number of chargers (ports) was approximately seven per affected CBG. The average normalized EV annual registration per 1,000 households was just over 27 in the affected CBGs in the 2020 baseline year.

Table 125. SDG&E Schools Pilot Summary Statistics of Effects on 33 Affected CBGs

	Change in Composite Measure of Access [a]	Change in Number of Chargers	Normalized Annual EV Registrations [b]	Number of Households [c]
CBG Mean	13.46	7.36	27.13	481.20
Standard Deviation	(32.74)	(4.62)	(26.21)	(218.04)

These values are averages for the CBGs whose access to public charging was affected by SDG&E's investments.

[a] Change in composite measure of access and number of chargers is from 2020 to 2025.

[b] Normalized annual EV registrations are average annual values in the affected CBGs in 2020 per 1,000 households.

[c] Number of households is based on 2015–2019 ACS.

The Evaluation Team calculated the impact of the Utility's investments in public charging for the Schools Pilot on neighboring EV ownership. This involved combining the OLS and IV-2SLS regression estimates of the impact of public charging access on EV registrations from Stage 1 with the estimates of the CBG changes in public charging access and household counts.[138] The impacts of the SDG&E investments on EV

[137] The Stage 1 analysis used vehicle registration data from 2015 to 2023, the most recent period with complete information at the CBG level. The EY2025 estimates assume that the impact of Utility-specific stations remains unchanged over time, which may not reflect actual market conditions and technological changes in 2025.

[138] In Stage 1, the Evaluation Team estimated the impact of public EV charging access on EV ownership. Stage 2 built on the Stage 1 analysis and was an attribution analysis of Utility-specific investments. A notable benefit of this approach is that it can be applied to evaluations of other programs that increase EV charging access, which allows methodological consistency.

registrations will depend on the extent to which investments increased access to EV charging in the affected CBGs and the number of households in the CBGs.

Table 126 shows estimates of the annual and cumulative EV registrations attributable to the SDG&E Schools Pilot charging investments. Based on the OLS long differences model,[139] SDG&E Schools Pilot investments in charging facilities increased EY2025 annual EV registrations by 26 vehicles and cumulative EV registrations by 61 vehicles. Based on the IV-2SLS long differences model, the Schools Pilot investments increased annual EV registrations by 50 vehicles and cumulative EV registrations by 150 vehicles. The Evaluation Team prefers the IV-2SLS-based estimates because they account for the potential endogenous siting decisions of public charging (i.e., siting public charging infrastructure in locations likely to have above- or below-average expected rates of EV adoption). These estimates reflect the 26 activated Schools Pilot facilities operating for a full year.

Table 126. SDG&E Schools Pilot Effects of Utility Investments on 2025 and Pilot-to-Date EV Registrations

	EY2025		Pilot to Date	
Analysis Model	OLS	IV-2SLS	OLS	IV-2SLS
Increase in EV Registrations	25.58	49.75	60.53	149.64
Standard Error	(4.64)	(15.15)	(7.37)	(27.21)

The Team estimated the OLS long differences using data for all CBGs in the analysis sample and estimated the IV-2SLS long differences for CBGs in the 20 largest California cities. The long differences are annualized eight-year estimates. For each affected CBG, the Team calculated the increase in annual registrations as the product of the regression-based access coefficient divided by eight, multiplied by the change in composite public charging access from utility investments (between baseline 2020 and EY2025), multiplied by the number of CBG households (in thousands). Robust standard errors clustered at the CBG level are in parentheses.

As in past evaluation years, the SDG&E Schools Pilot investments in public charging had economically meaningful impacts on EV ownership in EY2025. Across all 33 affected CBGs, the total number of EV registrations was about 895 (33 * 27.13) in baseline year 2020, so the preferred IV-2SLS regression estimates the cumulative impact of the SDG&E Schools Pilot through 2025 was an increase in EV registrations of about 16.7% (149.64/895) from 14.3% in EY2024. An average of 27 EV registrations per CBG puts these CBGs in the 62nd percentile of the EV registration distribution of CBGs, implying an average level of baseline EV registration.

SDG&E Parks Pilot

The Evaluation Team used the same approach as for the Schools Pilot to calculate the change in public charging access due to SDG&E's Parks Pilot investment for each CBG where the investments affected access. Table 127 shows that the pilot-to-date average change in the composite measure of access was almost 14 per affected CBG, and the average change in the number of chargers was close to four per

[139] The long differences model estimates indicate the impact of public charging on EV registration over eight years. The Team annualized these estimates by dividing the results by eight.

affected CBG. The average normalized EV annual registration per 1,000 households was just over 15 in the affected CBGs in the 2020 baseline year.[140]

Table 127. SDG&E Parks Pilot Summary Statistics of Effects on 21 Affected CBGs

	Change in Composite Measure of Access [a]	Change in Number of Chargers	Normalized Annual EV Registrations [b]	Number of Households [c]
CBG Mean	13.76	3.91	15.08	407.40
Standard Deviation	(6.69)	(5.64)	(12.01)	(177.35)

These values are averages for the CBGs whose access to public charging was affected by SCE's investments.

[a] Change in composite measure of access and number of chargers is from 2020 to 2025.

[b] Normalized annual EV registrations are average annual values in the affected CBGs in 2020 per 1,000 households.

[c] Number of households is based on 2015–2019 ACS.

Table 128 shows estimates of the annual and cumulative EV registrations attributable to the SDG&E Parks Pilot charging investments.[141] Based on the OLS long differences model, SDG&E's investments in Parks Pilot charging facilities increased EY2025 annual EV registrations by four vehicles and cumulative EV registrations by 15 vehicles. Based on the IV-2SLS long differences model, SDG&E's investments increased EY2025 annual EV registrations by eight vehicles and cumulative EV registrations by 41 vehicles. The Evaluation Team prefers the IV-2SLS-based estimates because they account for the potential endogenous siting decisions for public charging infrastructure (i.e., siting infrastructure in locations likely to have below- or above-average rates of EV adoption). These estimates reflect the operation of 11 activated Parks Pilot facilities over one year.

Table 128. SDG&E Parks Pilot Effects of Utility Investments on 2025 and Pilot-to-Date EV Registrations

	EY2025		Pilot to Date	
Analysis Model	**OLS**	**IV-2SLS**	**OLS**	**IV-2SLS**
Increase in EV Registrations	4.33	8.42	15.41	41.23
Standard Error	(0.49)	(1.58)	(0.88)	(3.48)

The Team estimated the OLS long differences using data for all CBGs in the analysis sample and estimated the IV-2SLS long differences for CBGs in the 20 largest California cities. The long differences are annualized eight-year estimates. For each affected CBG, the Team calculated the increase in annual registrations as the product of the regression-based access coefficient divided by eight, multiplied by the change in composite public charging access from utility investments (between baseline 2020 and EY2025), multiplied by the number of CBG households (in thousands). Robust standard errors clustered at the CBG level are in parentheses.

As in previous evaluation years, the SDG&E Parks Pilot investments in public charging had less impact on EV ownership than the Schools Pilot investments in public charging. Across all 21 affected CBGs, the total annual number of EV registrations was about 317 (21 * 15.08) in baseline year 2020, so the EY2025 impact

[140] Averages of the median income and percentage of multifamily housing units in affected CBGs puts the CBGs in the second median income quartile and the third multifamily housing quartile.

[141] The long differences model estimates indicate the impact of public charging on EV registration over eight years. The Evaluation Team annualized these estimates by dividing the results by eight.

of the SDG&E Parks Pilot boosts EV registrations by 2.7% (8.42/865), and the cumulative impact boosts EV registrations by 13.0% (41.23/316). The Evaluation Team expected the Parks Pilot to have a smaller impact than the Schools Pilot because it included fewer charging stations and ports and influenced fewer CBGs. Compared with EY2024, the percentage increase in EV registration has remained unchanged, reflecting the fact that no new stations became active under the Parks Pilot in EY2025.

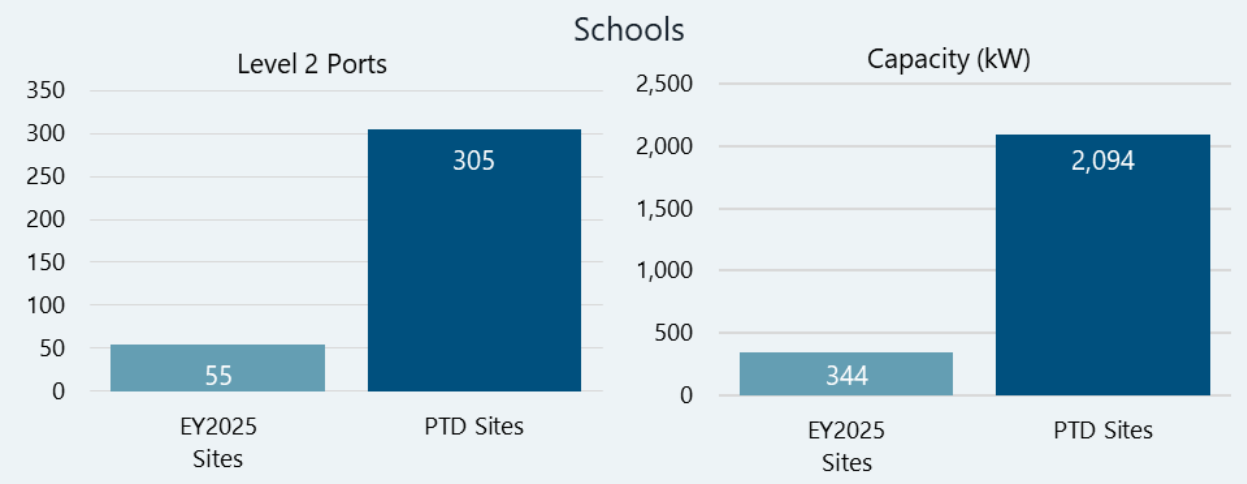
Highlights

- The model's output shows that the Schools and Parks Pilots may have contributed to the adoption of 150 and 41 EVs respectively in the program to date for households neighboring the infrastructure.
- As in the previous evaluation year, the Schools Pilot had a greater impact than the Parks Pilot, mainly due to the accessibility to the Schools Pilot charging facilities, which had more charging stations and chargers.

Site Visit Findings

The Evaluation Team visited all sites activated in EY2025, which included seven Schools Pilot sites. No Parks Pilot sites were activated in EY2025. During these site visits, the Team documented the number of ports installed in EY2025 (55 L2 and zero DCFC), amount of installed charging capacity (344 kW), number of parking spaces within reach of charging cords (88), and number of parking lots that include one or more Americans with Disabilities Act (ADA)-compliant spaces per site. This brought the total port count to 319 and installed capacity to more than 2.8 MW. Figure 294 and Table 129 show ports and capacity based on site visits in 2025 and prior years.

Figure 294. SDG&E Schools and Parks Pilots Ports and Capacity Observed in 2025 and Prior Years



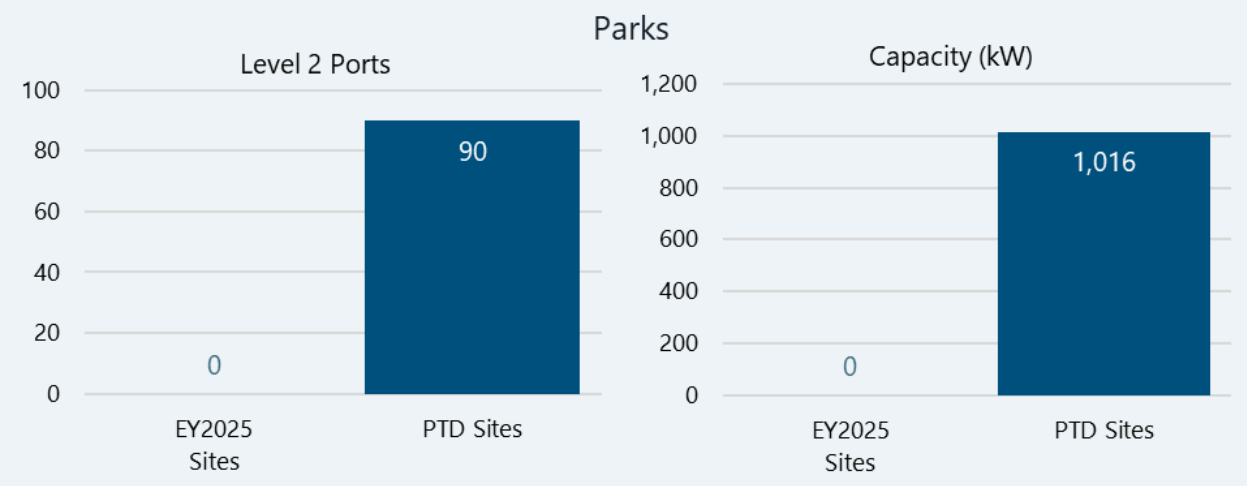


Table 129. SDG&E Schools and Parks Pilots Ports and Capacity Observed during 2025 Site Visits

Pilot	L2 Ports	DCFC Ports	Capacity (kW)	ADA Spaces	Connector
School 1	8	-	52	2	J1772
School 2	18	-	113	2	J1772
School 3	9	-	49	2	J1772
School 4	4	-	26	1	J1772
School 5	8	-	52	2	J1772
School 6	4	-	26	1	J1772
School 7	4	-	26	1	J1772
Total	55	0	344	11	

The seven sites SDG&E activated in the Schools Pilot in EY2025 represent a mix of sites primarily in urban-suburban areas of San Diego County, and one site in the Anza-Borrego Desert (Figure 295 shows a photograph taken at one of the site visits). Across the seven activated sites, an additional 344 kW of charging capacity was installed, supporting only L2 ports at four high schools, two community colleges, and one elementary school.

Figure 295. SDG&E Schools and Parks Pilots Remote Charging Location in the Desert



Many of the sites in the SDG&E Schools Pilot continue to expand charging access by increasing the ratio of parking spaces within reach of charging ports. This is often achieved by installing charging between two rows of parking spaces, as shown in Figure 296 where 18 charging ports can reach 39 parking spaces.

Figure 296. SDG&E Schools and Parks Pilots Example of High Access L2 Charging Layout



One installation used switchgear previously installed at a different site. The Utility reported that its project supply house provides used equipment when it meets construction requirements, enabling more efficient use of resources. One of the site hosts provided their own chargers, which resulted in the installation of a single-port charger within reach of three parking spaces. This site also ended up with a 5 kW dual-port charger, whereas the same model at this and most other pilot sites typically provides 12.5 kW, limiting customer benefit. Although a 75 kVA, 208 V transformer was installed at this site, EV charging capacity was limited by a 200-ampere meter panel, preventing the electrification of more parking spaces (Figure 297).

Figure 297. Variety of L2 Chargers at SDG&E Schools and Parks Pilot Site

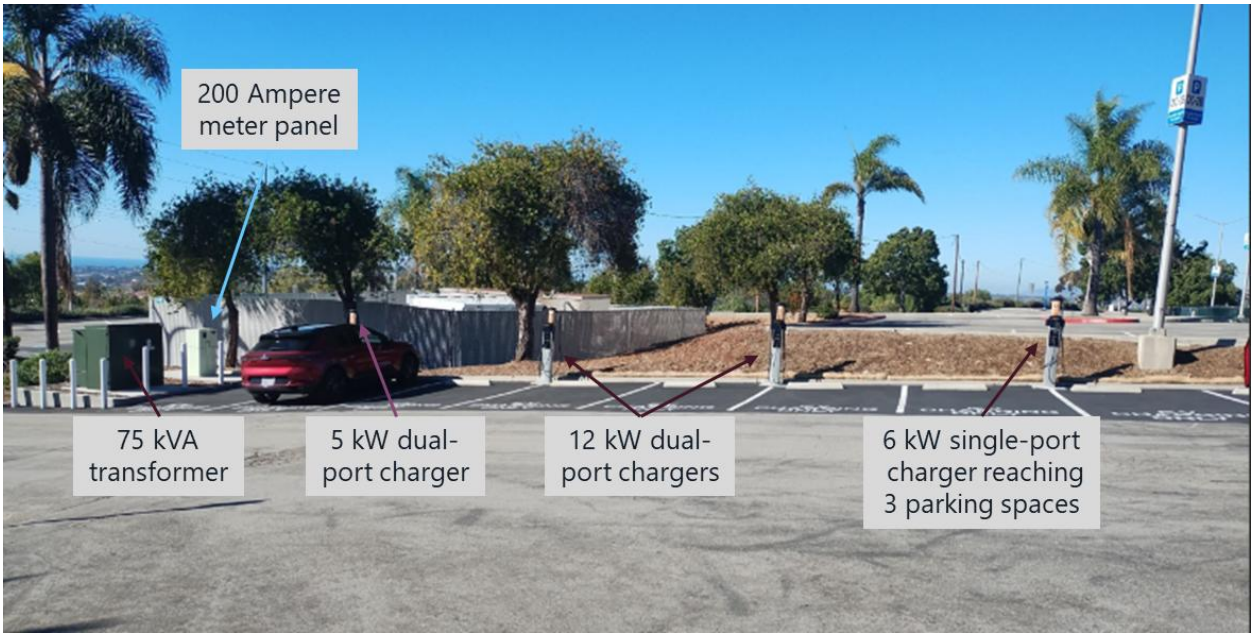
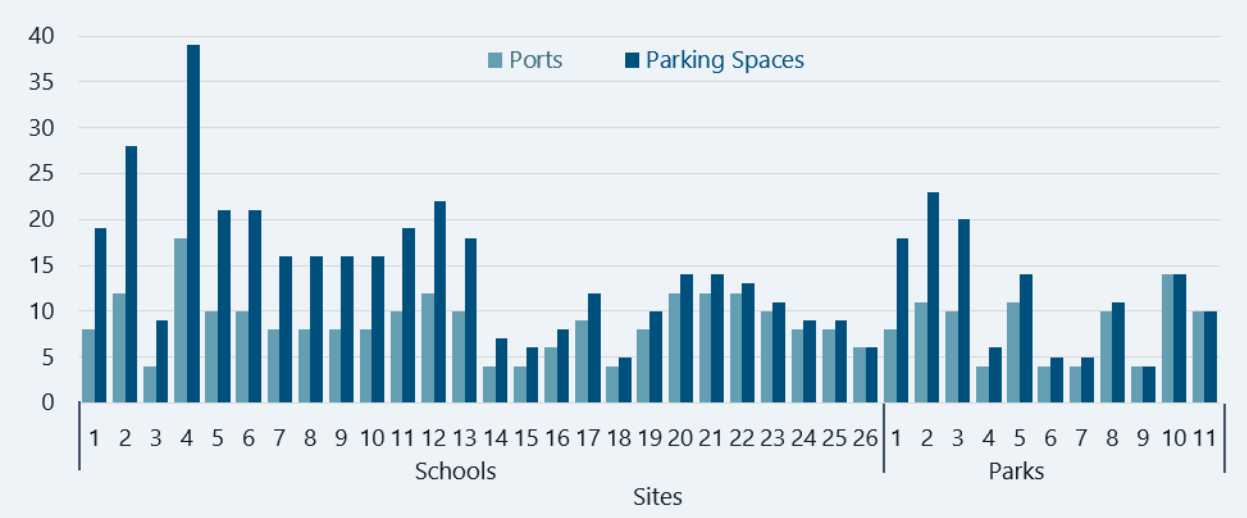


Figure 298 shows the number of ports and the number of parking spaces accessible to those ports at the sites visited by Evaluation Team in the pilot to date. Higher access ratios may increase utilization of charging infrastructure by facilitating turnover of charging ports and enabling resiliency if one or more ports are unavailable. Overall, these sites average 1.6 parking spaces within reach of a charging port. One EY2025 site achieved a ratio of 2.2 parking spaces that can be reached by a single port, which is close to the highest ratio observed for Schools and Parks Pilots of 2.4.

Figure 298. SDG&E Schools and Parks Pilots Visited Sites Charging Port Availability by Site



Unique to SDG&E's portfolio of Schools Pilot and Parks Pilot sites is that the Utility owns all the site charging infrastructure. The Utility contracts with a single NSP, which acts as the customer of record for all

program sites. As in previous years, at the time of site visits, there were EVSE energized but unavailable for public access due to significant delays in commissioning. However, the brand of hardware the sites use is programmed to allow several free charging sessions per EVSE (L2 and DCFC). Some EV drivers have learned that key fobs can begin charging sessions even when the stations are not fully commissioned on the network, allowing them free charging for a limited time period.

The Evaluation Team does not typically ask site hosts questions about the background of these sites. However, because one site had still not been commissioned 11 months after energization, the site host proactively asked the Evaluation Team staff when charging would be available, or how to otherwise expedite their already lengthy wait. According to Utility staff, the NSP has continued to experience extensive staff turnover, which has led to poor communication. However, the NSP expected commissioning times to improve. The Evaluation Team has not communicated directly with NSP staff to understand the specific causes of the delays.

Since SDG&E owns the charging infrastructure, the Utility's NSP passes its TOU rates directly to EV drivers. As a result, all EV drivers receive a message via charging rates on the EVSE display or through the NSP phone application that may help influence their charging habits in ways that support VGI. No idle fees were noted by any of the seven new sites at the time of this report. Additional details can be found in the *Grid Impacts* section.

There are several attributes that distinguish SDG&E from other IOUs. One is that SDG&E owns all of the AB1082 and AB1083 projects, which may provide greater purchasing power for hardware and NSP fees, such as networking and warranties. SDG&E has also elected to use TOU-based tariffs for the customer of record (who receives bills) and for EV drivers charging at these sites. This may help EV drivers at these sites learn how pricing works and adjust their charging patterns to take advantage of lower-cost periods and avoid higher-cost electricity.

Highlights

- SDG&E installed 55 new L2 ports, totaling an additional 344 kW of charging capacity. This brings port totals for PTD sites to 304 L2 and 15 DCFC ports for more than 2.8 MW of installed charging capacity.
- As in past years, extended commissioning delays at times approaching a year have led to low use for the community, questionable perception impacts, and free energy to some drivers.
- Using a single NSP to operate all PTD SDG&E sites (network and maintenance) may have created a dynamic where the vendor is not compelled to provide timely service due to a lack of competition or may have created a bottleneck delaying provision of service.
- All sites provide TOU pricing to drivers, potentially improving VGI.

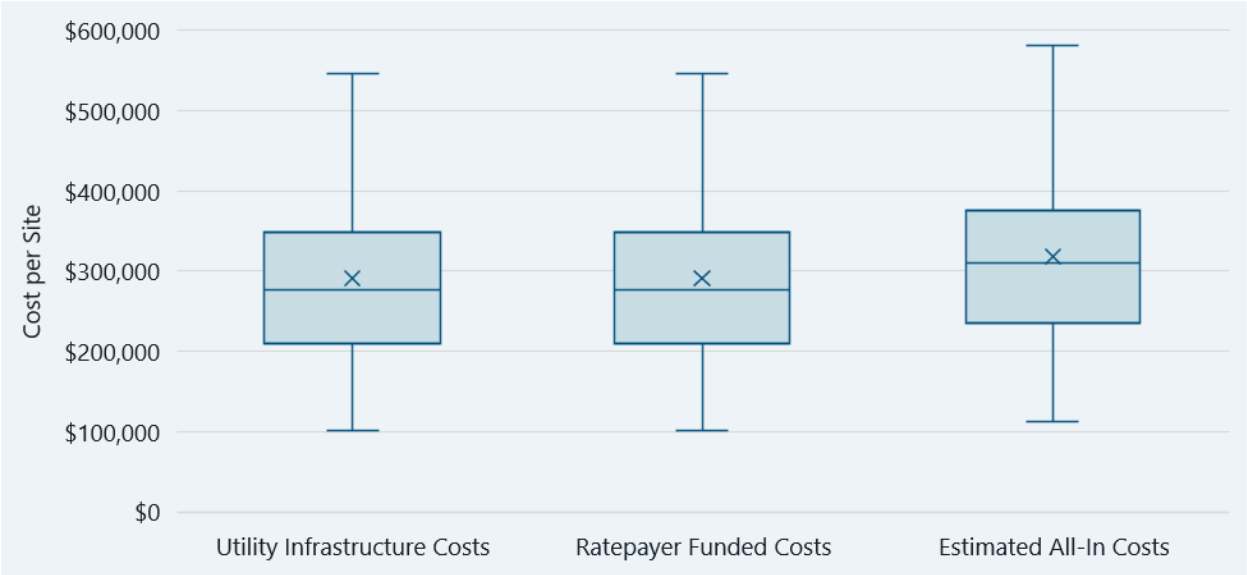
Site Costs

The Evaluation Team conducted a cost analysis of 22 school sites and 11 park sites activated in the pilots to date, with fully closed-out finances as of December 31, 2025. The set of fully closed-out sites is smaller than the set of activated sites because of the time required to perform tasks such as collecting receipts, paying invoices, and obtaining administrative approvals. Cost estimates presented here are in nominal dollars. The 33 sites had a mix of L2 and DCFC ports, with an average of approximately nine ports and 190 kW of installed capacity.

Figure 299 shows the distribution of site-level costs for the 33 sites. The horizontal lines of the boxes show the 25th, 50th, and 75th percentiles of sites; the X denotes the mean site cost; and the three panels are defined as follows:

- **Utility Infrastructure Costs.** Site costs borne by SDG&E for TTM and BTM.[142]
- **Ratepayer-Funded Costs.** All site costs borne by SDG&E, calculated by summing actual TTM costs paid by SDG&E, BTM costs paid by SDG&E, and estimated EVSE rebates paid by SDG&E.
- **Estimated All-In Costs.** The total cost of capital and installation borne by SDG&E and the customer, calculated by summing actual TTM costs paid by SDG&E, BTM costs paid by the customer or by SDG&E, and estimated EVSE costs.[143]

Figure 299. SDG&E Schools and Parks Pilots Program Per-Site Costs Organized by Three Perspectives, Across 33 Closed-out PTD Sites



[142] Values are the same as the ratepayer-funded costs, excluding the EVSE estimates.

[143] The Evaluation Team estimated EVSE equipment costs using an assumption of $3,000 per port for L2 ports and $45,000 per port for DCFC ports.

Figure 300 shows the average estimated all-in costs for the 33 sites. BTM has the largest cost across the sites, followed by TTM and then EVSE. Together, the average all-in TTM, BTM, and EVSE cost is $318,274 through 2025.

Figure 300. SDG&E Schools and Parks Pilots Average All-In Costs, Across 33 Closed-out PTD Sites

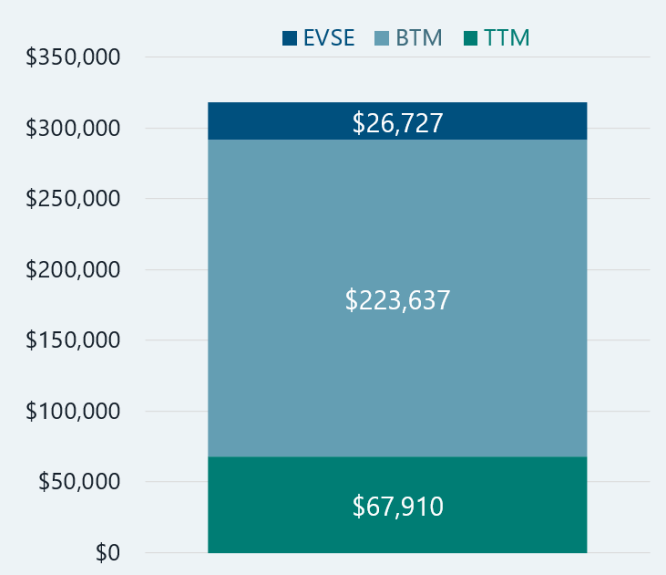


Figure 301 shows the distribution of Utility infrastructure costs (corresponding to the far-left panel in Figure 299) presented per site and per kilowatt. The average Utility infrastructure cost of TTM and BTM borne by SDG&E across PTD sites was $291,547 per site[144] and $2,502 per kilowatt.[145]

[144] Calculated by summing all TTM and SDG&E-sponsored BTM costs and dividing by the number of sites. Number reflects maximum infrastructure rebate offered for sites that have not yet applied for rebates, which may vary significantly from actual infrastructure rebate amount paid.

[145] Calculated by summing all TTM and SDG&E-sponsored BTM costs and dividing by the sum of installed capacity.

Figure 301. SDG&E Schools and Parks Pilots Cost Per Site and Per Kilowatt Across 33 Closed-Out PTD Sites



Highlights

- All-in costs paid by SDG&E vary widely between sites, with an average cost of $318,274 per PTD site. BTM was the largest cost across the sites, followed by TTM and then EVSE.
- The average cost of SDG&E-sponsored TTM and BTM across PTD sites was $291,547 per site and $2,502 per kilowatt.

Grid Impacts

Reporting for SDG&E Schools Pilot and Parks Pilot is divided into two sections. This section focuses on the Schools Pilot sites. The Evaluation Team assessed grid impacts for the SDG&E Schools Pilot by analyzing energy consumption of operational charging stations installed through the Pilot through the end of EY2025, combined with NSP charging session data.

Data Sources

The primary data sources for this section are energy usage data reported at regular 15-minute intervals from AMI and data provided by NSPs. There are several key differences between AMI and NSP data. AMI data reflect only energy usage, whereas NSP data provides energy usage, session start and stop time, the duration of a vehicle's connection to a charging port, the duration of a vehicle actively pulling power, and the specific port used for a session. However, AMI meters track standing loads (such as those the EVSE use for communications, cooling, active power converters, solenoids, and screens), which NSPs typically cannot do. When AMI data are missing from the dataset, the Evaluation Team uses NSP data to fill the gaps.

Summary of Schools Pilot Grid Impacts

Table 130 presents the estimated grid impacts form the SDG&E Schools Pilot.

Table 130. SDG&E Schools Pilot Program Grid Impacts

Impact Parameter	Actual 2025 [a]	PTD Actual	10-Year Projection PTD
Operational Sites	7	25	25
Installed Capacity (kW)	288	1,790	1,790
Electric Energy Consumption, MWh	656	1,444	5,855
On-Peak (4 p.m. to 9 p.m.) MWh (and % of total)	93 (14%)	220 (15%)	N/A
Maximum Demand, kW (with date and time)	483 (10/21/25 9:45 a.m.)	483 (10/21/25 9:45 a.m.)	N/A
Maximum On-Peak Demand, kW (with date and time)	294 (10/9/25 6:30 p.m.)	294 (10/9/25 6:30 p.m.)	N/A

[a] Energy consumption, peak consumption, and demand data are based on PTD activated sites for calendar year 2025.

The remainder of this section offers detailed findings on actual consumption, demand, and charging session-oriented trends of all Schools Pilot PTD sites through EY2025.

Energy Trends

Seven Schools Pilot sites were activated in EY2025, bringing the total activated sites through the end of 2025 to 26. The seven new sites added 288 kW of installed capacity, bringing total installed capacity to 1,790 kW for PTD sites. Sites in the SDG&E Schools Pilot reached 656 MWh of total consumption in EY2025, bringing the total consumption for PTD sites to 1,444 MWh. Maximum demand surpassed 483 kW (at 9:45 a.m. on October 21, 2025). Similar to past evaluation years, maximum demand was approximately one-third of the total installed capacity of nearly 1,800 kW.

Figure 302 plots monthly energy consumption and maximum demand values for the Schools Pilot sites. The figure shows a general upward trend in consumption month over month. Demand grew significantly in September and peaked in October 2025, coincident with the school year.

Figure 302. SDG&E Schools Pilot Monthly Energy Consumption and Maximum Demand

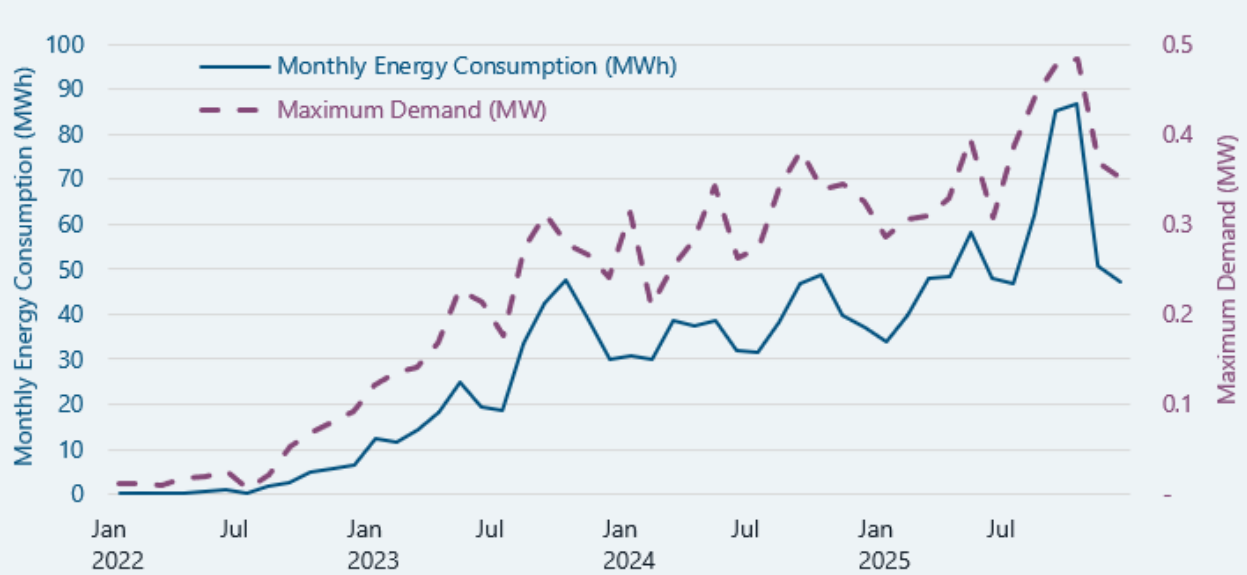


Figure 303 shows daily consumption and maximum demand through 2025. Daily consumption ramped up in the latter half of 2025 to over 4 MWh, before tapering significantly during December, coincident with the school year. This marks a significant increase over EY2024, where daily consumption never exceeded 2.5 MW. Maximum demand also increased throughout EY2025, reaching nearly 500 kW, up from 300 kW in EY2024.

Figure 303. SDG&E Schools Pilot Daily Consumption and Maximum Demand, Pilot-to-Date Sites

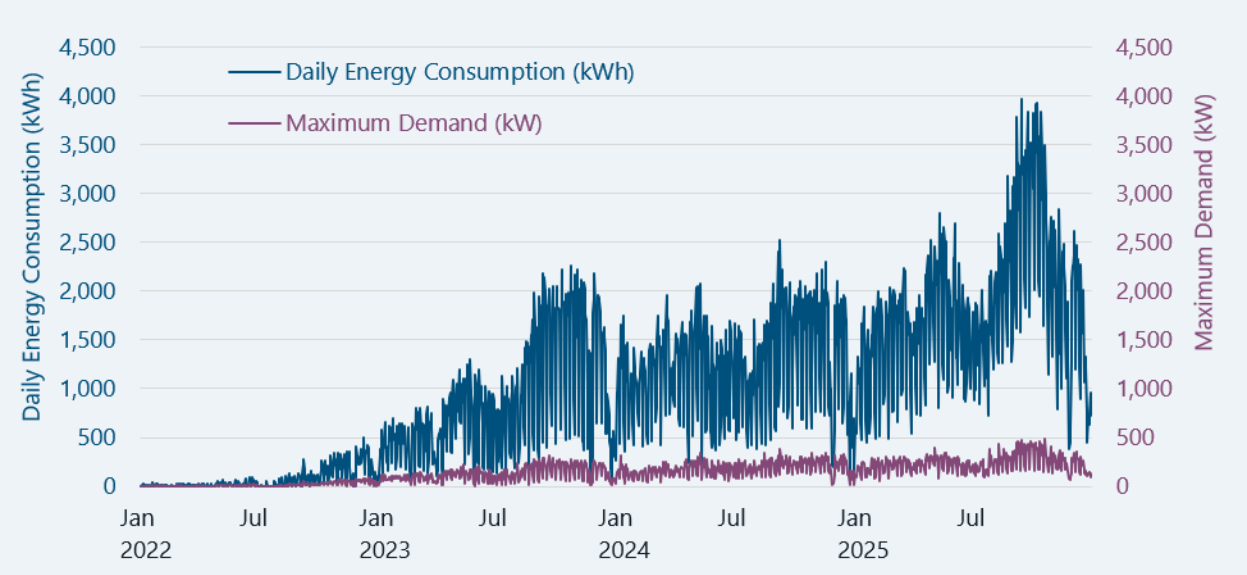
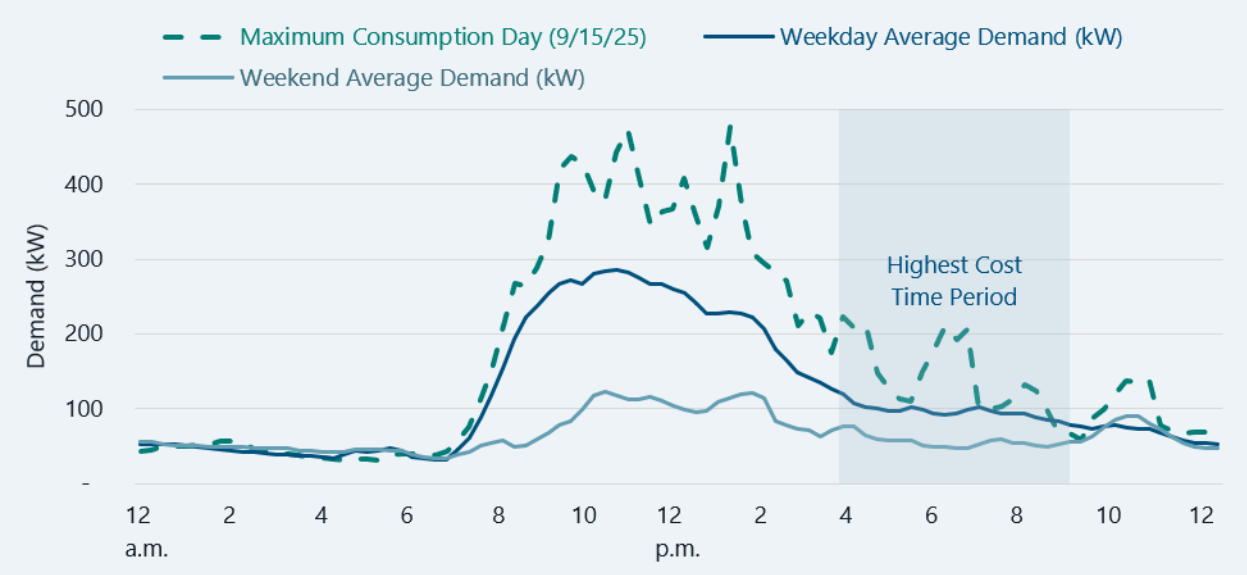


Figure 304 highlights average weekdays, weekends, and the highest utilization day in EY2025. Notably, these are workplace-oriented sites and therefore expected to see activity primarily on workdays during work-hours. However, as shown in the figure, activity occurs in the evenings and on weekends. Weekends

are relatively flat, maintaining 50 kW and increasing in late mornings until late afternoons. Weekdays show a pattern of demand that closely aligns with workday activities, with a strong ramp-up from 7 a.m. to 9 a.m. followed by a slow taper for the rest of the day. A closer look at high utilization sites with unanticipated weekend and overnight charging is found in the next section *Usage Trends*.

Figure 304. SDG&E Schools Pilot Average Weekday and Weekend September through November 2025 Load Curves



Usage Trends

Twenty-six sites were active in the Schools Pilot to close out the year. The Evaluation Team analyzed site performance over time to assess the extent to which the portfolio and individual sites are maturing in terms of utilization. The Team evaluated program characteristics by comparing energy consumption, load factor (a measure of usage consistency), and the total number of charging sessions across sites. The analysis began with a site's initial charging sessions, rather than when AMI data first became available, to eliminate early periods when chargers were powered up but not necessarily commissioned by their NSPs (e.g., during testing) or not available for public use. The Team defined month zero as the month when public access began.

Growth in consumption and number of charging sessions may indicate to what extent EV drivers are aware of these EVSE and find them helpful to their charging habits, or that the new charging availability is influencing drivers of conventional vehicles to transition to PEVs.

Figure 305 and Figure 306 show monthly energy consumption trends for active sites—showing kilowatt-hours by month and load factor by month—grouped by whether they have achieved a 20% load factor to improve data visualization. This allows analysis at the site level, rather than overall pilot reporting on how often sites are used over time. In past evaluation years, multiple sites had extended commissioning timelines; only one site had delayed commissioning in EY2025.

Eight sites have achieved 5 MWh in a single month, displaying customer adoption of the charging site. However, nine sites have consumption largely from the EVSE's standby load. Two of the highest consuming sites also include DCFC ports, whereas all sites have L2 charging.

Figure 305. SDG&E Schools Pilot Monthly Consumption Based on Sites' Operational Time, Load Factor <20%

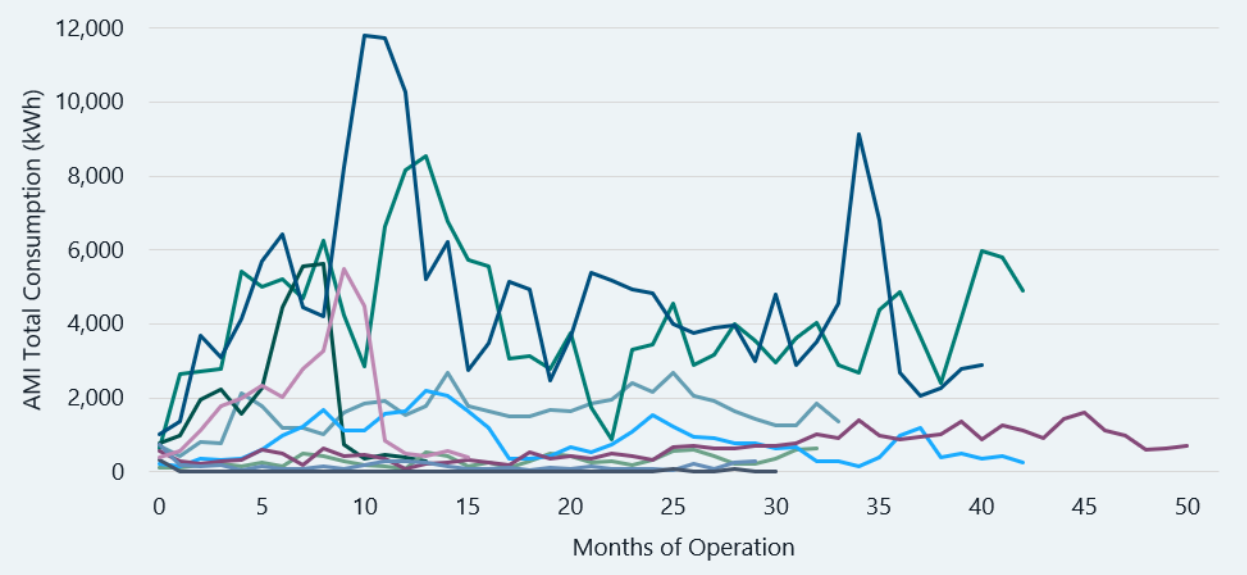


Figure 306. SDG&E Schools Pilot Monthly Consumption Based on Sites' Operational Time, Load Factor >20%

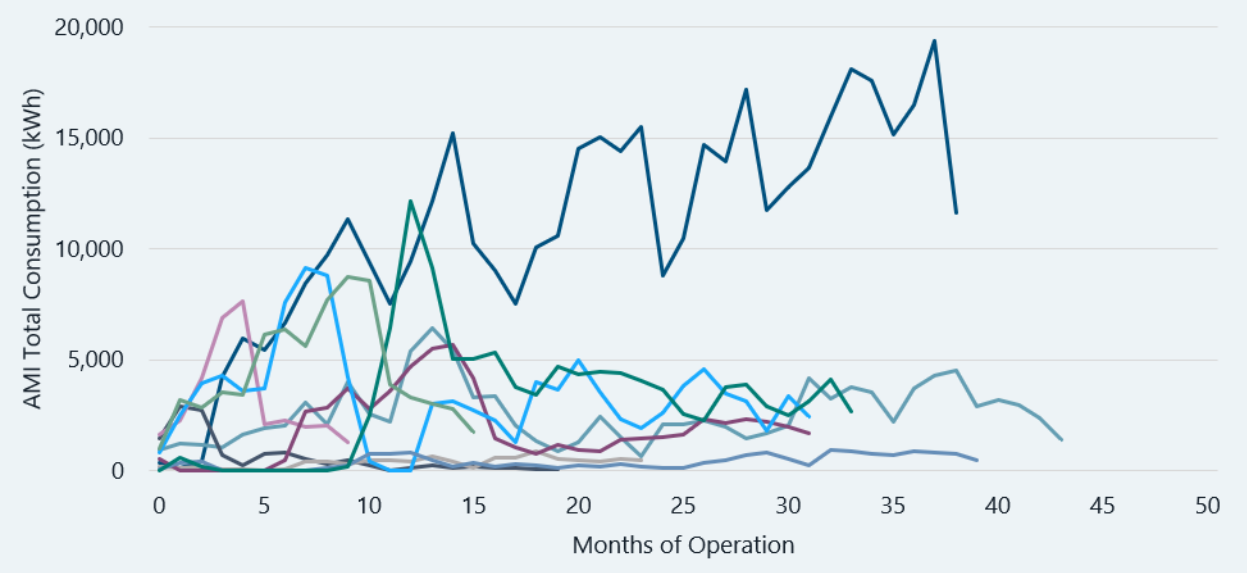


Figure 307 and Figure 308 show the monthly load factor of Schools Pilot sites. Load factors compare a site's actual monthly energy consumption to what it would have been if it had achieved the 15-minute interval of maximum demand for the entire month. A constant demand, for example, would result in a

100% load factor (which is considered impossible). This is not necessarily a marker of how much capacity is being utilized (demand vs. installed capacity).

As shown in Figure 308, several sites regularly approach 20%, with several exceeding that, while a handful of sites with lower utilization have a hard time achieving 5% or even 10%.

Figure 307. SDG&E Schools Pilot Monthly Load Factor Based on Sites' Operational Time, Load Factor >20%

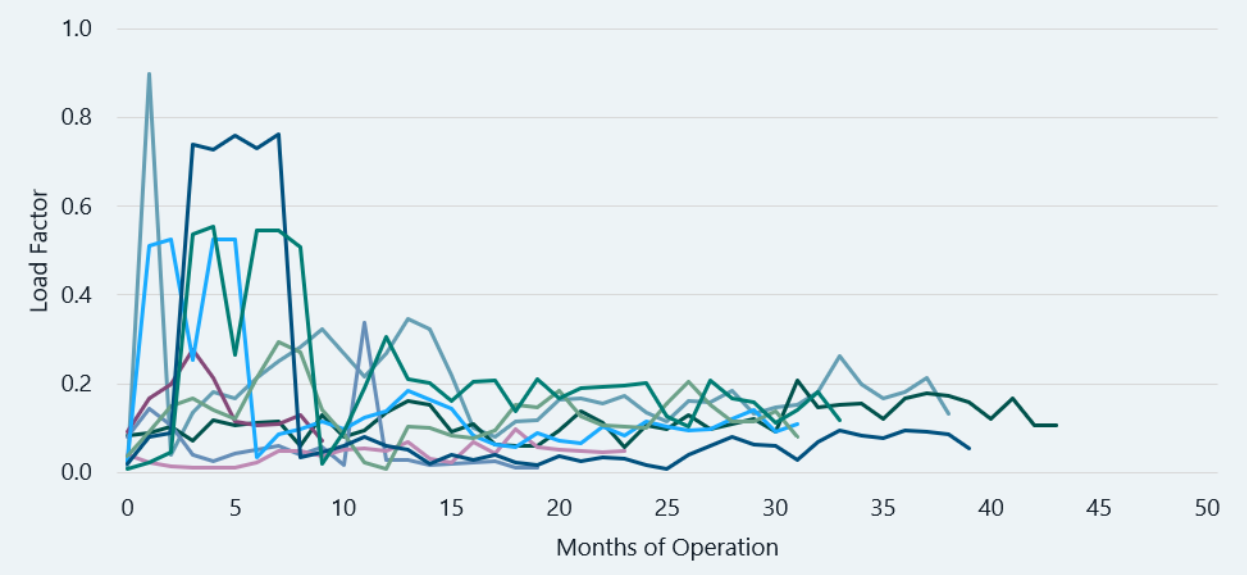
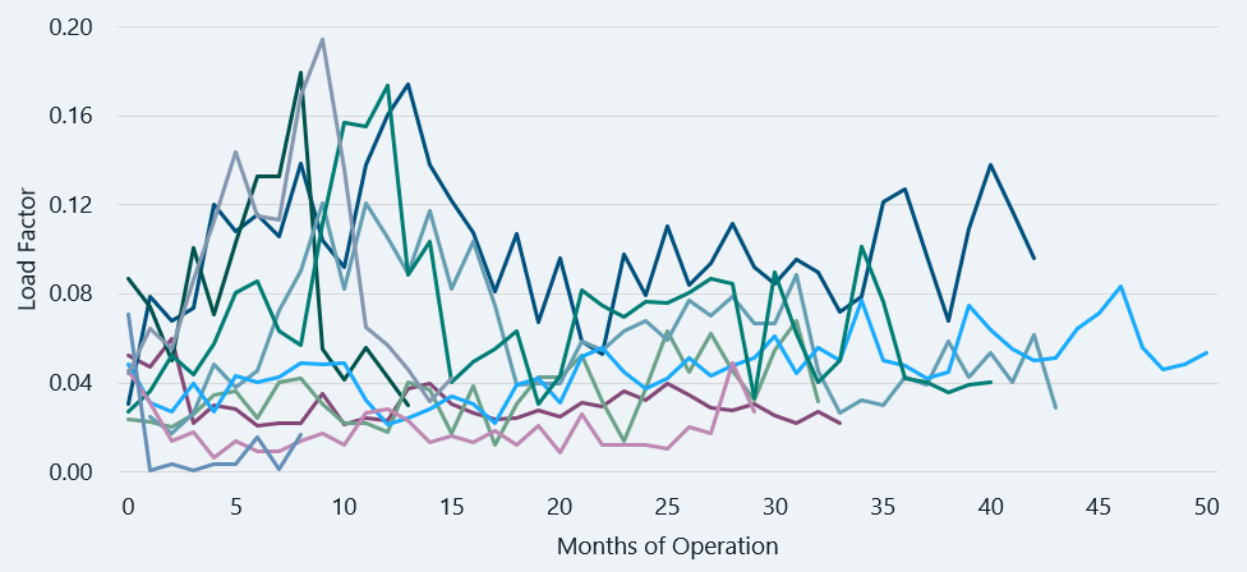


Figure 308. SDG&E Schools Pilot Monthly Load Factor Based on Sites' Operational Time, Load Factor <20%



High Utilization Sites: Weekend and Overnight Examples

Six of the Schools Pilot sites show much higher utilization overnight and or on weekends than would be expected for a workplace charging site. These sites have three distinct charging periods: Monday through Friday business hours, overnight, and weekend, which appear to function as public EV charging resources, rather than private sites. The Baseline Weekday series in Figure 309 includes all active pilot sites and shows a distinct, short-duration increase in load on weekday mornings that tapers off steadily during business hours. At times, the example load curves are more jagged due to higher-power DCFC charging at some sites. Baseline sites have minimal overnight load on both weekdays and weekends. However, the figure also shows that several high-utilization sites have double or triple the demand on weekends and overnight than the baseline average.

Figure 309. SDG&E Schools Pilot Demand per Port Comparing Baseline and High Utilization Sites

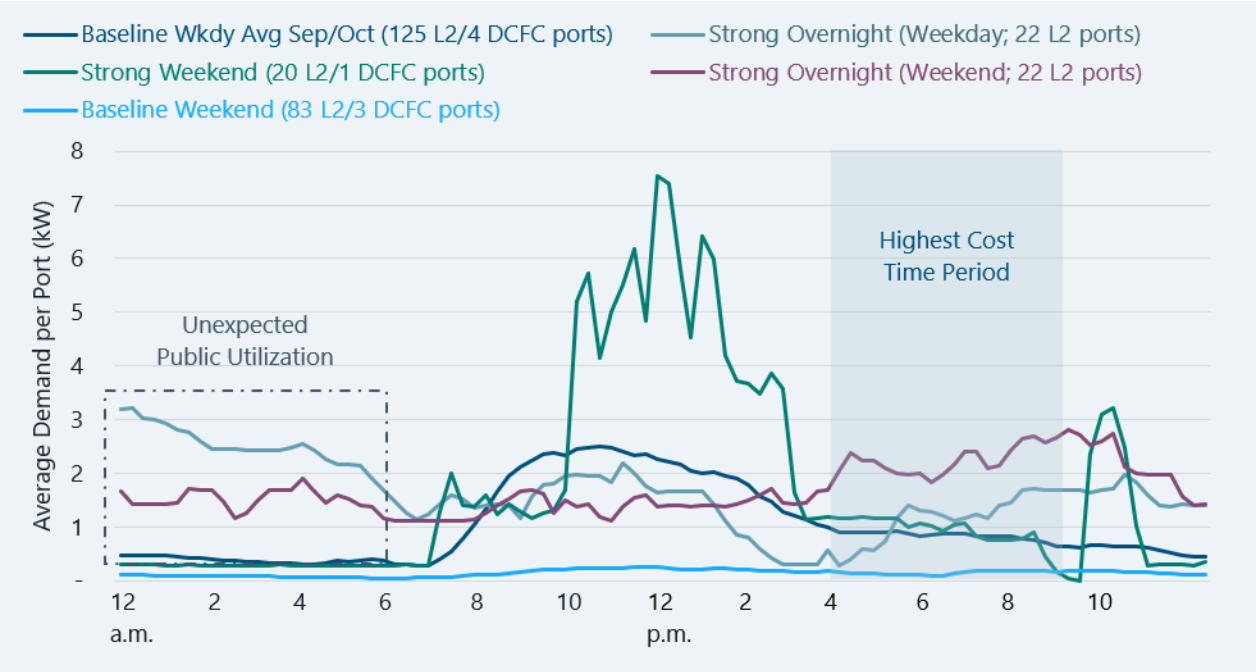


Figure 310 presents the daily rate of the nearly 70,000 total charging sessions at Schools Pilot sites, with approximately 30,000 of these sessions in EY2025. Because the sites are within school districts, utilization dips noticeably during summer and winter breaks. The number of charging sessions increased steadily throughout EY2025, rising from 100 sessions per day to over 175 sessions per day by the end of the year.

Figure 310. SDG&E Schools Pilot Daily Charging Sessions for PTD Sites

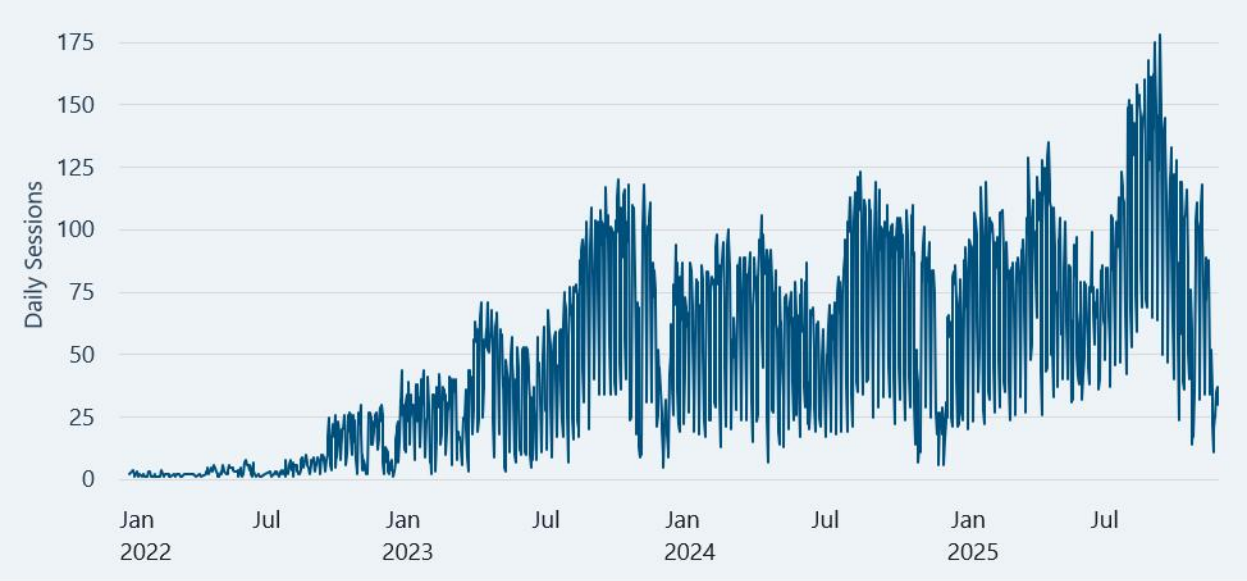


Figure 311 presents the distribution of charging sessions by consumption (kilowatt-hours) for all sites in the Schools Pilot to date. The Evaluation Team did not include erratic charging sessions (below 1 kWh or less than 0.1 hours). As shown, while nearly half of all L2 charging sessions continued to be small (up to 12 kWh), the proportion of small sessions relative to total sessions has decreased compared with previous years. Similarly, large charging sessions of 50 kWh or more increased in frequency in EY2025 compared with prior years. Very few sessions of 50 kWh or more took place with these L2 EVSE but have increased with time.

In comparison, DCFC charging shows 25 kWh to 50 kWh sessions continue to be common, accounting for approximately 40% of all sessions in EY2025 and in each prior year. Large sessions over 75 kWh have grown slightly year over year.

Figure 311. SDG&E Schools Pilot Charging Session Count by Consumption Size for PTD Sites

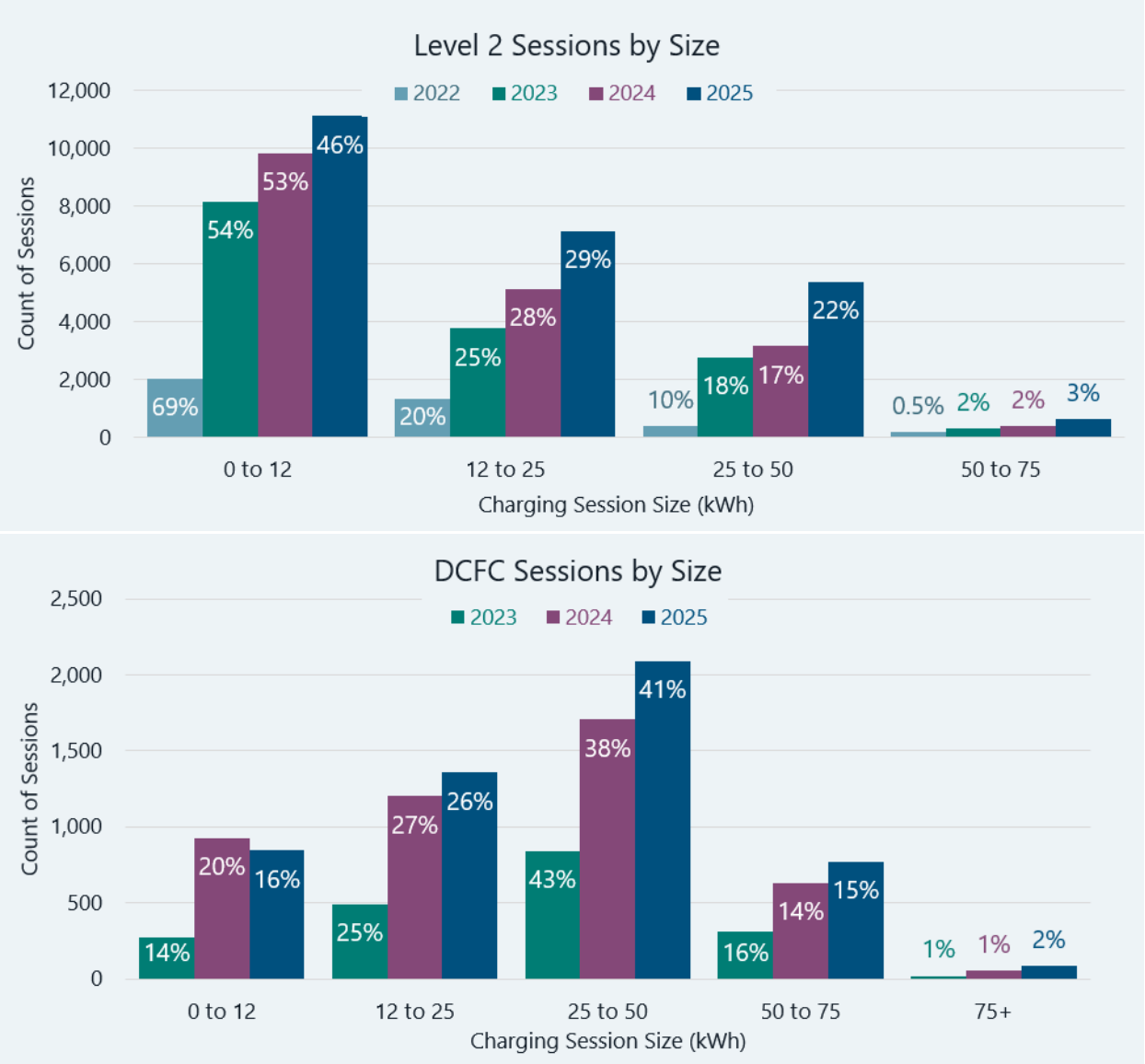
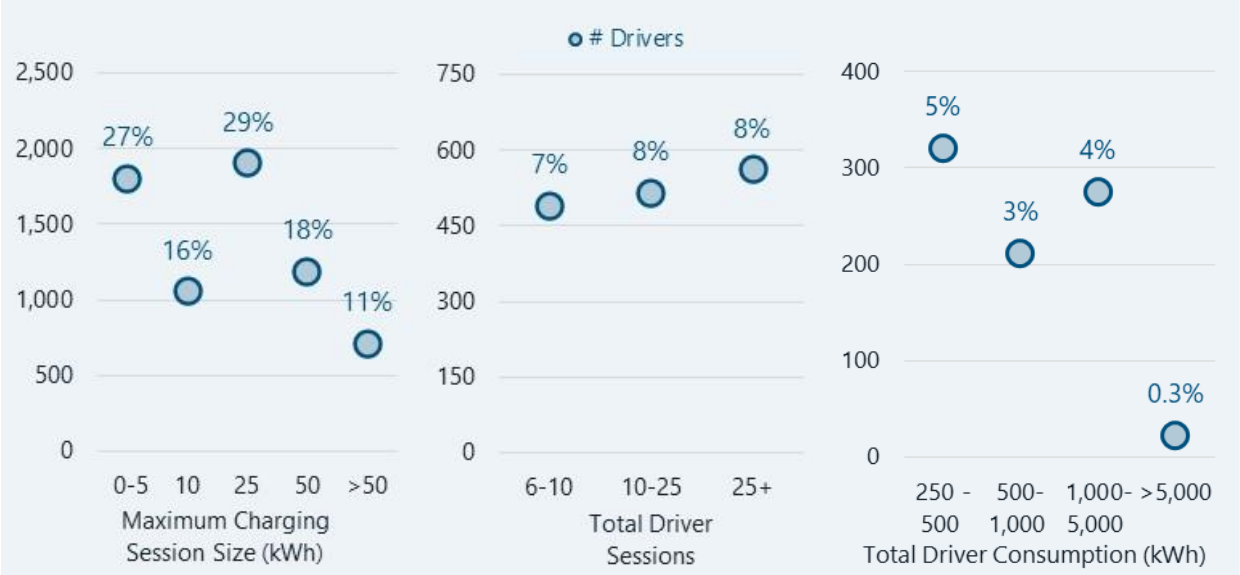


Figure 312 highlights driver statistics. Over 6,600 drivers appear to have used these sites, with nearly 25% charging more than five times, and almost 140 drivers having more than 100 sessions.

Through the end of EY2025, several thousand unique and anonymous drivers were recorded using the Schools Pilot charging sites. As seen in the leftmost chart of Figure 312, just over 75% of these drivers were new or infrequent users, with six or fewer total sessions during the lifetime of the pilot. Approximately 25% of drivers could be considered frequent users with six or more charging sessions. Nearly 5% of drivers are very frequent users, with at least 25 charging sessions. Charging session sizes vary, with a fairly even distribution, as seen in the middle chart. Twenty-three drivers clearly relied heavily on the charging stations, with each consuming between 5,000 kWh and 13,000 kWh in the program to date.

Figure 312. SDG&E Schools Pilot Driver Statistics



Represents 100% of drivers | Represents 24% of drivers | Represents 12% of drivers

Summary of Parks Pilot Grid Impacts

Table 131 presents the estimated SDG&E Parks Pilot program grid impacts.

Table 131. SDG&E Parks Pilot Grid Impacts

Impact Parameter	Actual 2025 [a]	Actual PTD	10-Year Projection PTD
Operational Sites	0	11	11
Installed Capacity (kW)	0	1,016	1,016
Electric Energy Consumption, MWh	570	1,409	3,862
On-Peak (4 p.m. to 9 p.m.) MWh (and % of total)	102 (18%)	253 (18%)	N/A
Maximum Demand, kW (with date and time)	404 (10/11/25 11:45 a.m.)	404 (10/11/25 11:45 a.m.)	N/A
Maximum On-Peak Demand, kW (with date and time)	252 (6/4/25 6:30 p.m.)	252 (6/4/25 6:30 p.m.)	N/A

[a] Energy consumption, peak consumption, and demand data are based on PTD activated sites for calendar year 2025.

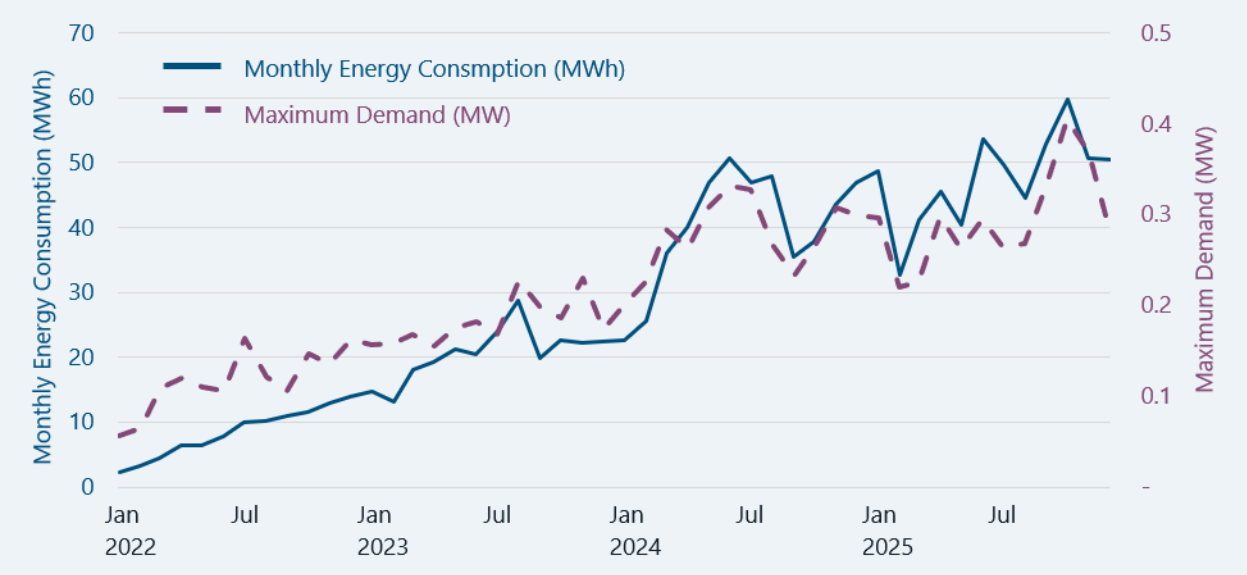
The remainder of this section presents detailed findings on actual consumption, demand, and charging session-oriented trends of the combined sites through calendar year 2025.

Energy Trends

No pilot sites were activated in 2025, and therefore, the total operational sites remained at 11. Figure 313 plots monthly energy consumption and maximum demand values for PTD sites in the Parks Pilot. Parks sites consumed over 570 MWh in 2025, totaling more than 1,400 MWh in the pilot to date. Monthly consumption often exceeded 50 MWh, peaking at 60 MWh at the end of the year. Maximum demand also frequently exceeded 300 kW in 2025, peaking at over 400 kW toward the end of the year, while total

installed capacity was approximately 1,000 kW. This is similar to trends observed in prior evaluation years, with capacity continuing to be several times more than typical demand.

Figure 313. SDG&E Parks Pilot Monthly Energy Consumption and Maximum Demand



As presented in Figure 314, total daily energy consumption generally follows an upward trend over time, with daily consumption and the number of charging sessions continuing to peak in the summer. Consumption approached 2.5 MWh daily midyear, with demand often around 200 kW and peaking above 400 kW.

Figure 314. SDG&E Parks Pilot Daily Consumption and Maximum Demand, Pilot-to-Date Sites

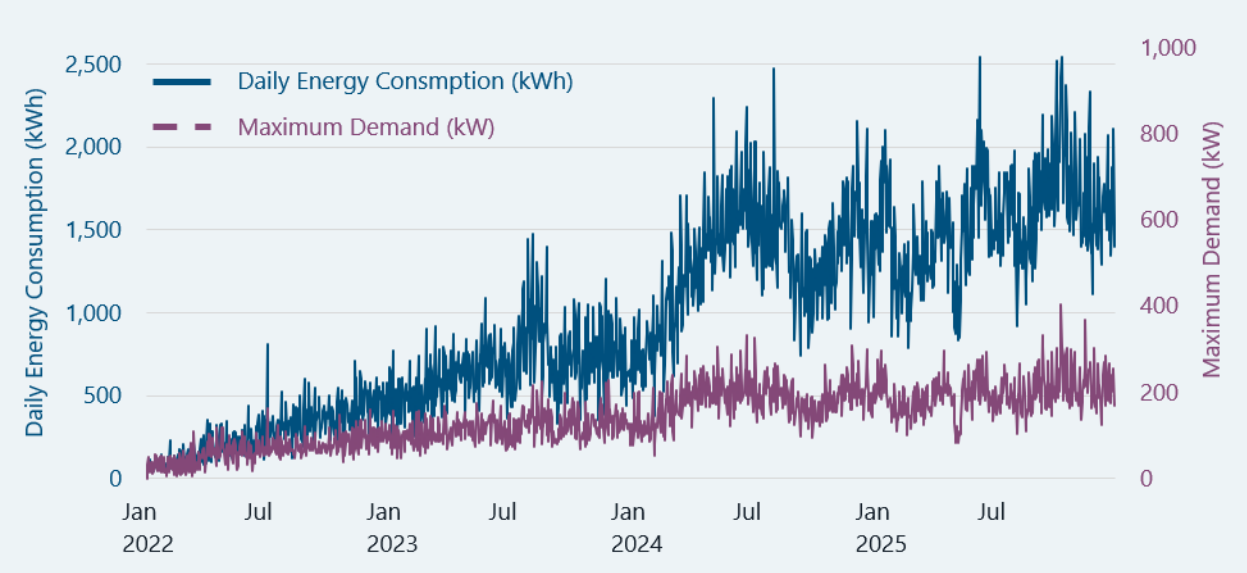
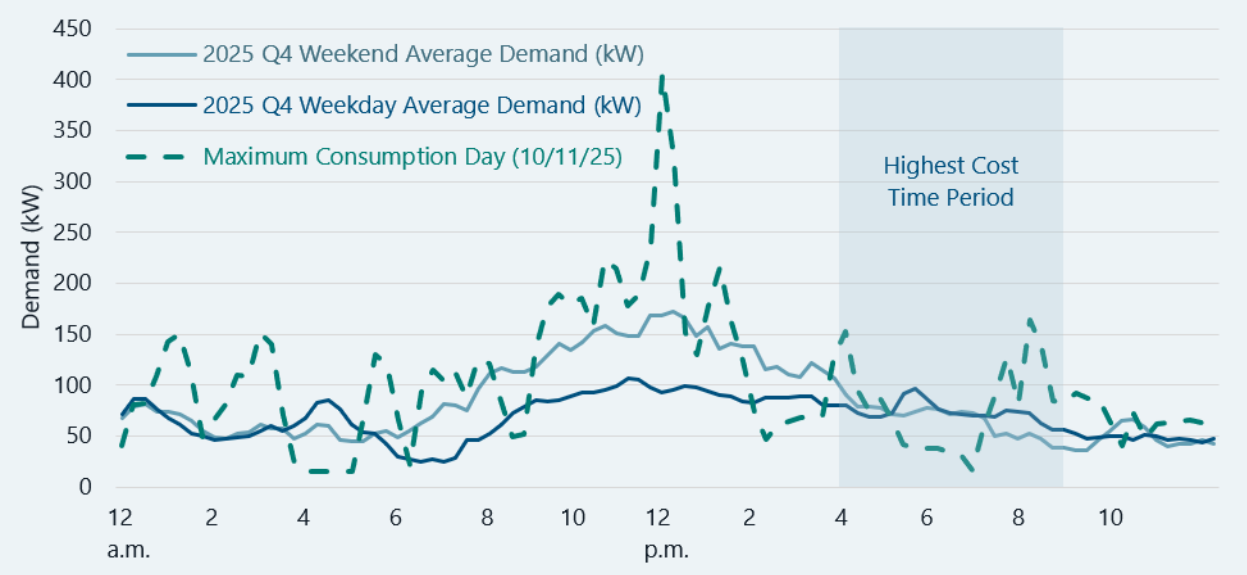


Figure 315 highlights average weekday and weekend load curves in the fourth quarter of 2025, as well as a high utilization day (Saturday, October 11, 2025) that reached 400 kW for comparison. This was more

than double the average weekend demand and almost four times the average weekday demand. Charging load remained fairly flat on weekdays, with a slight ramp-up midday, and generally saw less demand than weekend charging. Each example load curve shows charging very late at night, highlighting public use throughout the day.

All of the Parks Pilot sites bill EV drivers based on one of SDG&E's EV-oriented TOU tariffs. It is expected that this variation in pricing may eventually influence when EV drivers choose to charge at these sites as has been seen in residential examples outside this portfolio. However, the Evaluation Team did not observe a correlation between TOU pricing and consumer behavior at Parks Pilot sites.

Figure 315. SDG&E Parks Pilot Average Weekday and Weekend Q4 2025 Load Curves



Usage Trends

With multiple sites in the Parks Pilot having reached several years of operations (around four years), the Evaluation Team was able to analyze site performance over time. The Team evaluated program characteristics by comparing energy consumption, load factor (a measure of consistency of usage), and total charging sessions across sites. This analysis began with a site's initial charging sessions, rather than when AMI data first became available, to eliminate early periods when chargers were powered up but not necessarily commissioned by their NSPs (e.g., during testing) or not available for public use. The Team defined month zero as the month when public access began.

Figure 316 shows sites' monthly consumption based on operational age, organized by the first month of public charging access for each site, as opposed to the calendar month. Early months with zero or standby only consumption were removed. This allows a comparison of sites based on their age and illustrates how long it takes for a public charging location to mature into a resource for EV drivers.

Five sites show utilization below 2 MWh monthly, while four show regular monthly consumption above 5 MWh. All four top performers have two DCFC ports on site. Six sites have never reached 1 MWh in a month; at least one appears unused and the rest show 50 sessions per month at the most.

Figure 316. SDG&E Parks Pilot Monthly Consumption Based on Sites' Operational Age

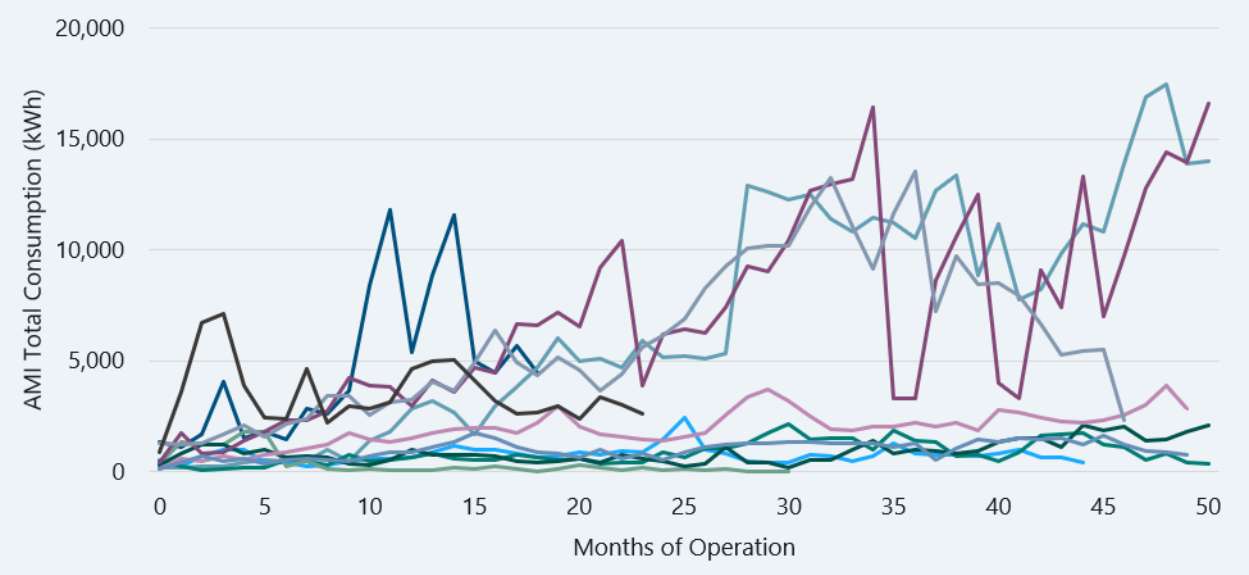
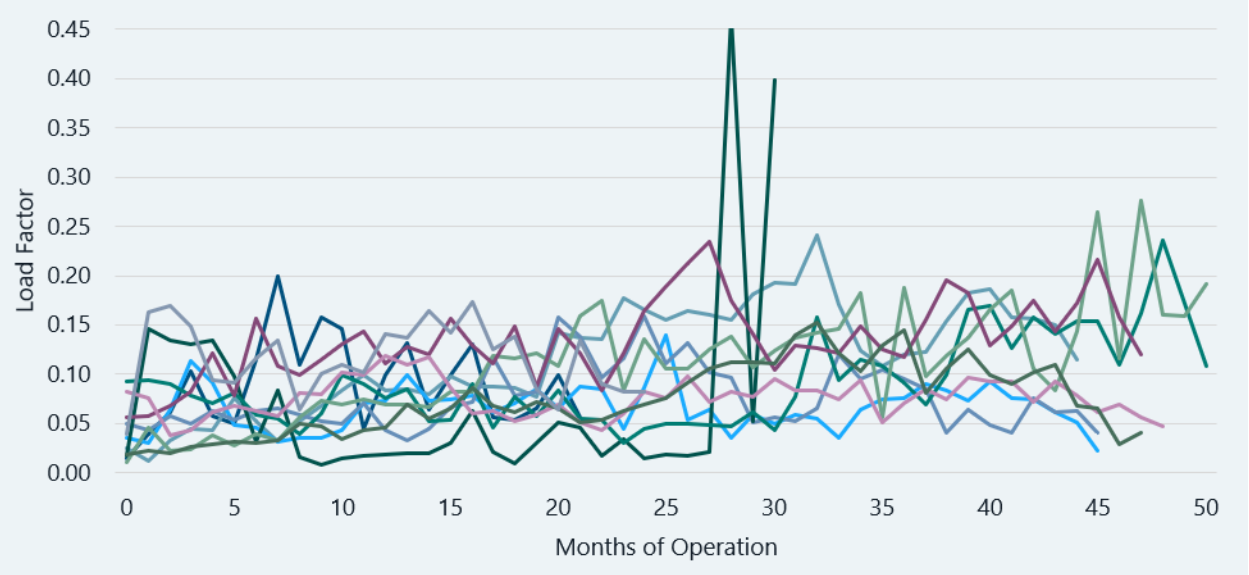


Figure 317 shows the sites' monthly load factor, also based on their operational age. Load factors compare a site's actual monthly energy consumption to what it would have been if it had achieved the 15-minute interval of maximum demand for the entire month. A constant demand, for example, would result in a 100% load factor (which is considered impossible). This is not necessarily a marker of how much capacity is being utilized (demand vs. installed capacity).

Figure 317 reveals the majority of sites in the Parks Pilot have a maximum monthly load factor of typically <20%. Overall, the load factor suggests that maximum demand is highly variable at most sites, reflecting low utilization or slow uptake by EV drivers at these sites.

Figure 317. SDG&E Parks Pilot Monthly Load Factor Based on Sites' Operational Age



High Utilization Sites: Weekend and Overnight Examples

Figure 318 highlights differences between baseline (average) performing Parks Pilots and those with high utilization, either weekend or overnight. The Team averaged load curves over the second half of 2025. The baseline weekday and weekend data are from all pilot-to-date sites. The Strong Weekend is a subset of sites that display greater than average charging during the weekends, while the Strong Overnight displays greater than average overnight charging, both during the week and on weekends.

As shown, several sites had significant overnight usage. Notably, there were load spikes just after midnight, as well as at 4 a.m. Also unique to this subset is the high level of charging taking place from 4 p.m. to 9 p.m., when energy costs are highest.

Figure 318. SDG&E Parks Demand per Port Comparing Baseline and High Utilization Sites

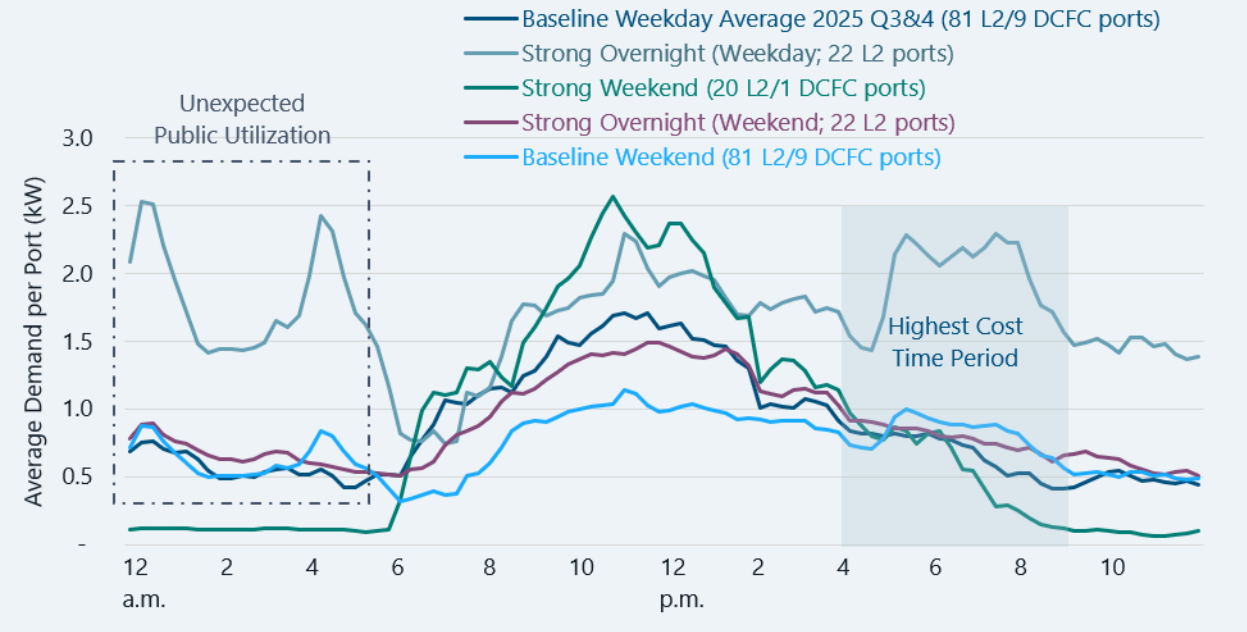


Figure 319 presents the total number of charging sessions in the Parks Pilot to date. Over 65,000 charging sessions have occurred in the pilot to date, with approximately 22,000 in EY2025. The number of daily charging sessions across the population of sites increased less quickly in 2025 despite spiking in mid-2024. Sessions have averaged around 60 daily sessions from mid-2024 through the end of 2025, often ranging between 30 and 80 charging sessions.

Figure 319. SDG&E Parks Pilot Daily Charging Sessions for PTD Sites

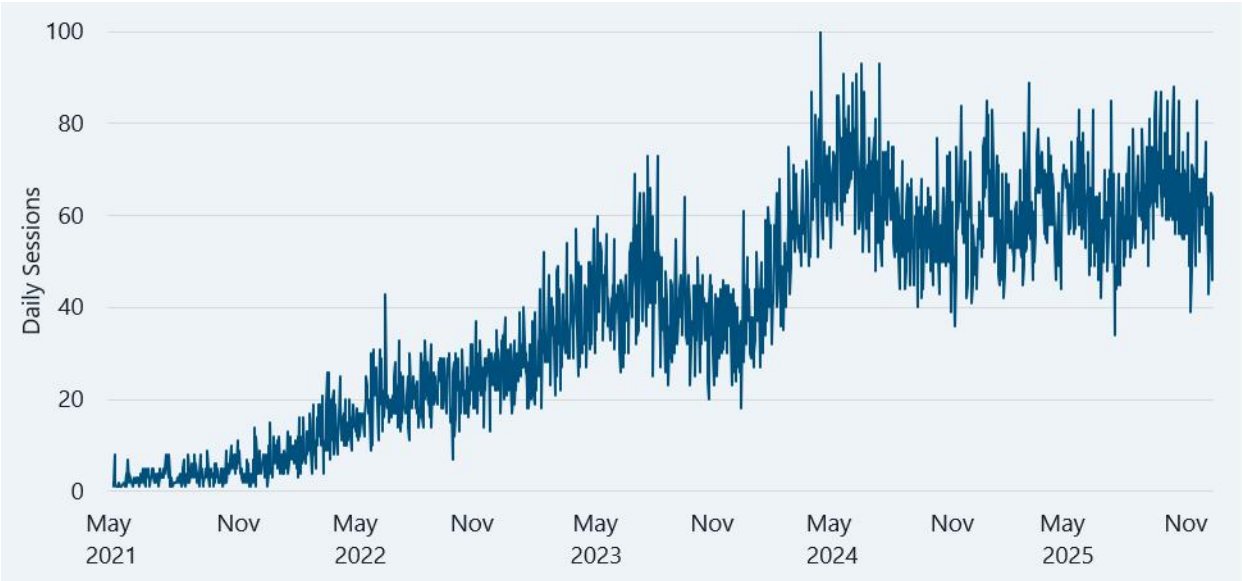


Figure 320 presents the distribution of charging sessions by consumption (kilowatt-hours) for all sites in the Parks Pilot to date. The Team did not include erratic charging sessions (below 1 kWh or less than

0.1 hours). L2 charging sessions of up to 12 kWh dropped to 57% in EY2025 but continued to represent over half of all L2 charging sessions. Charging sessions between 12 kWh and 25 kWh increased to 22% in EY2025, and charging sessions between 25 kWh and 50 kWh increased to 19%. While very few sessions of 50 kWh or more took place with these L2 EVSE, these sessions increased to 3% in EY2025.

In comparison, DCFC charging sessions between 25 kWh and 50 kWh continued to be common, accounting for approximately 40% of all sessions in EY2025 and EY2024. Large sessions over 75 kWh also remained similar between EY2025 and EY2024.

Figure 320. SDG&E Parks Pilot Charging Session Count by Consumption Size for PTD Sites

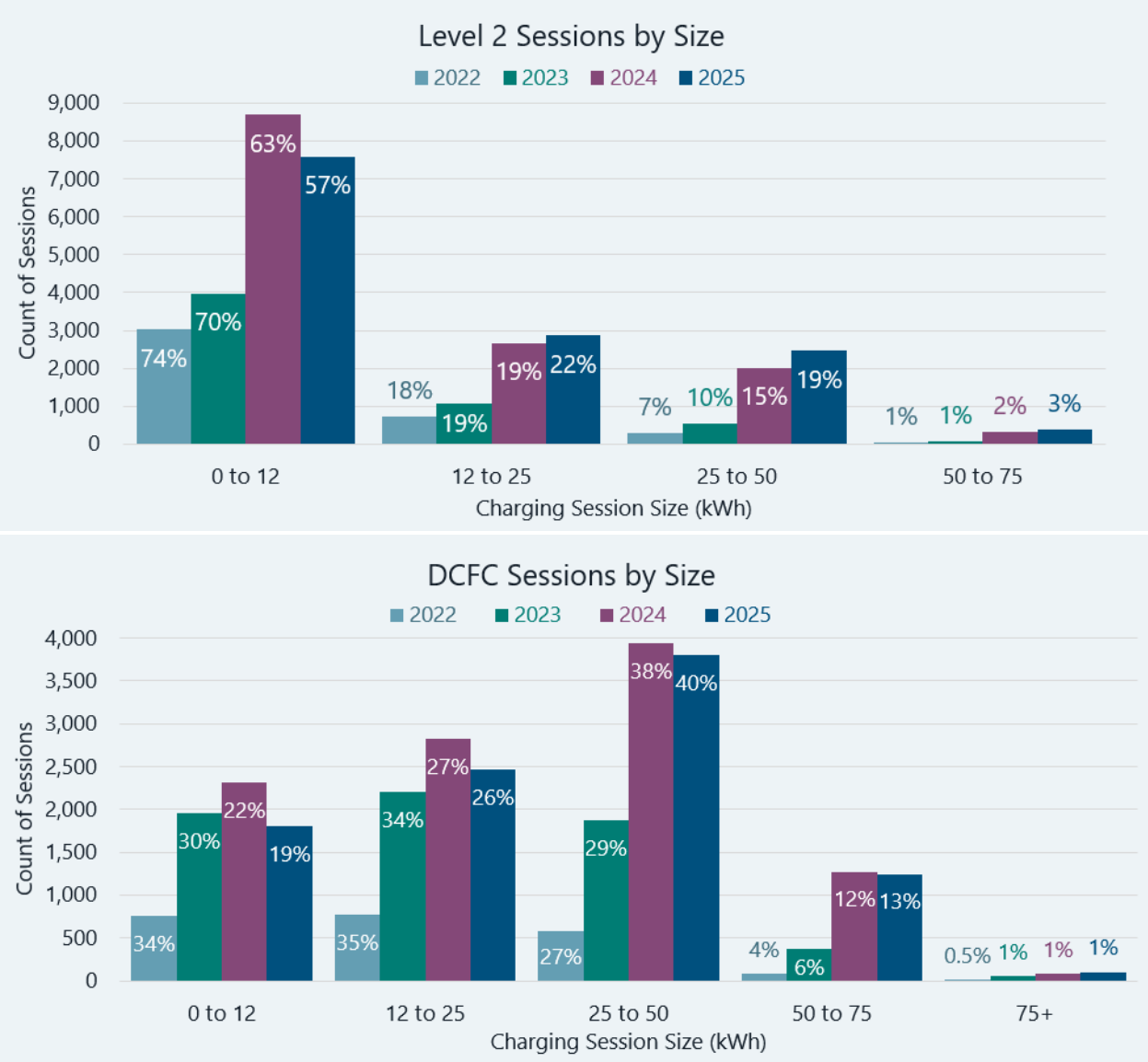


Figure 321 highlights driver statistics. The Parks Pilot appears to have supported nearly 10,000 drivers to date. Of those, over 15% are repeat visitors with six or more charging sessions, and nearly 500 drivers have had 25 or more charging sessions at Parks Pilot sites. As illustrated in the figures, total consumption

by driver shows that around 10% consumed more than 250 kWh. Three hundred drivers have consumed more than 1,000 kWh, while 23 drivers have each consumed between 5,000 and 25,000 kWh, indicating these charging stations have proven a reliable resource.

Figure 321. SDG&E Parks Pilot Driver Statistics



Represents 100% of drivers | Represents 17% of drivers | Represents 11% of drivers

Highlights

- Parks and Schools Pilot sites have a diversity of utilization. Higher-utilization sites may see hundreds of monthly sessions, while low-utilization sites may see only 25 or fewer sessions per month.
- Several Schools Pilot sites support public access to use charging stations on weekends or overnight, which enhances the benefits to the local community and SDGE ratepayers.
- Some Parks Pilot sites show significant overnight usage, which may mean they are supporting EV drivers in nearby multi-unit dwellings, which are well known as challenges to implement EV charging.
- Examples of hundreds of drivers who use these sites regularly show that these sites are reliable and facilitate people's adoption of EVs.
- TOU rates may influence EV driver charging behavior as they become more proficient
- Fewer sites experienced significant delays in charger commissioning in EY2025 than in past years.

Petroleum Displacement

The Evaluation Team estimated pilot-induced petroleum displacement attributable to the 26 Schools Pilot and 11 Parks Pilots sites using three key pieces of information: electricity used for EV charging, calculated annual EV miles traveled, and equivalent annual counterfactual vehicle petroleum fuel consumption. From this information, the Team estimated the reduction in equivalent gallons of petroleum attributable to the Schools and Parks Pilots. Table 132 presents the Schools and Parks Pilots' petroleum displacement

impacts through 2025, including estimated actual impacts for 2025, actual impacts to date for all pilot sites, and a 10-year forecast for PTD sites.

Table 132. SDG&E Schools and Parks Pilots Petroleum Displacement Summary

DAC	Usage (n=37)				Petroleum Displacement (GGE)		
	2025 Actual [a] (kWh)	PTD Actual [b] (kWh)	2025 Actual (miles)	PTD Actual (miles)	2025 Actual	PTD Actual	10-Year Projection
Inside DAC	813,699	1,939,723	2,396,953	5,732,782	65,562	160,516	475,867
Outside DAC	412,361	913,209	1,218,002	2,707,265	30,523	69,045	258,698
Total	1,226,060	2,852,931	3,614,955	8,440,047	96,085	229,561	734,564

[a] "2025 Actual" represents the data from all activated sites from program inception for the 2025 calendar year.
[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Highlights

- The 37 operational Schools and Parks Pilot sites collectively achieved an impact of over 229,000 gallons of petroleum in the pilot to date, with 70% within DACs.
- Over a 10-year period, these 30 sites will displace more than 734,000 gallons of petroleum.

Greenhouse Gas and Criteria Pollutant Impact

The Evaluation Team calculated reduced emissions from displaced fossil fuel use by ICE vehicles that were not in service due to the SDG&E Schools and Parks Pilots. To establish a baseline, the Evaluation Team developed one ICE counterfactual and calculated the emissions associated with these vehicles under conditions that otherwise matched those of the EVs. Although EVs have no tailpipe emissions, the fossil-fuel power plants that supply electricity to the vehicle chargers still release some GHGs and criteria pollutants.

Table 133 presents the GHG reduction resulting from the 26 operational Schools Pilot sites and 11 operational Parks Pilot sites in 2025, along with the pilot-to-date and 10-year totals, by impact location. Overall, the Pilots have resulted in 83% reduction of GHG emissions (1,838 MT) relative to the counterfactual to date (2,204 MT, not shown in the table), with 68.5% of the impact in DACs.

Table 133. SDG&E Schools and Parks Pilots GHG Reductions Summary

DAC	Usage (n=37)				GHG Reduction (MT)		
	2025 Actual [a] (kWh)	PTD Actual [b] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
Inside DAC	813,699	1,939,723	2,396,953	5,732,782	532	1,260	4,120
Outside DAC	412,361	913,209	1,218,002	2,707,265	263	578	2,360
Total	1,226,060	2,852,931	3,614,955	8,440,047	795	1,838	6,480

[a] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.
[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Of the local emissions, the pilots had the highest impact in reducing CO, resulting in an estimated annualized reduction of nearly 192 kg and a projected 10-year reduction of more than 21,000 kg (Table 134).

Table 134. SDG&E Schools and Parks Pilots Local Emissions Net Reductions

Emissions	EY2025 Sites Annualized (n=7)			PTD Sites (n=37)	
	Inside DAC	Outside DAC	Total [a]	Actual	10-Year Projection
PM_{10} (kg)	0.20	0.24	0.44	9.09	31.1
$PM_{2.5}$ (kg)	0.19	0.22	0.41	8.36	28.6
ROG (kg)	2.06	2.42	4.48	156.10	613.6
CO (kg)	88.15	103.63	191.78	5,274	21,049.3

[a] Columns may not sum to total due to rounding.

Figure 322 shows the current mix of electricity from the CAISO grid used for charging vehicles in the SDG&E Schools and Parks Pilots sites.[146] Based on the real-time grid conditions when EV charging occurred, the overall energy mix comprised about 63% zero emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear), 26% natural gas, and 11% imports. As the CAISO grid adds more renewables to meet the Renewable Portfolio Standard, GHG and criteria pollutant emissions will continue to decrease over time.

Figure 322. SDG&E Schools and Parks Pilots Net Electricity Mix, Pilot-to-Date Sites

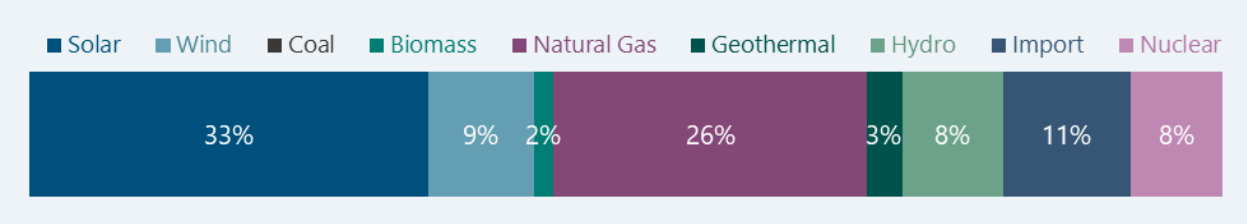
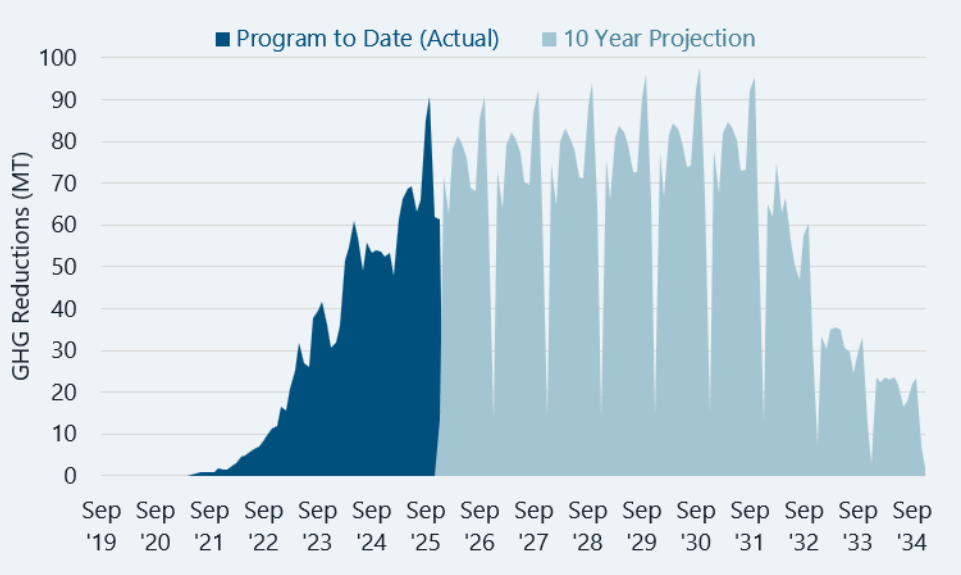


Figure 323 shows how pilot GHG reductions have increased to date and how these reductions are expected to grow over time for all activated sites. The analysis period ranges from the activation of the first pilot sites through the end of 2025. The analysis incorporates the net reduction (counterfactual emissions minus utility emissions) for each site in the Schools and Parks Pilots. Pilot-to-date emissions reductions are shown in dark blue, and anticipated benefits based on annualization are presented in a lighter blue. Since each site has its own starting date of operation, the 10-year sunset for each site will gradually taper off of pilot benefits starting in 2032. This taper reflects that benefits are no longer counted after 10 years, as this is beyond the useful life of the chargers, although the sites could continue to use the infrastructure beyond 10 years. While each year's operations appear similar, several key factors drive variations, such as seasonality of Utility generation sources (high Utility emissions appear as a dip on the

[146] The power associated with imports comes from a mixture of hydro, nuclear, and natural gas plants located outside of the CAISO grid.

curves), holidays occurring on weekends versus weekdays, and inaccuracies in predicted operations for sites that became operational late in 2025.

Figure 323. SDG&E Schools and Parks Pilots Historical and Forecasted GHG Reductions, Pilot-to-Date Sites



Highlights

- In 2025, the Schools and Parks Pilots sites resulted in an 83% reduction of GHG to date, with 68% of the impact occurring within DACs.
- The greatest reduction in local emissions in 2025 was CO, with a projected 10-year period reduction of more than 21,000 kg.
- Based on the real-time grid conditions when the EV charging occurred, the overall energy mix contained about 63% zero emissions or renewable sources of electricity (including solar, wind, hydro, geothermal, biomass, and nuclear) and 26% natural gas.

Health Impacts

The Evaluation Team calculated public health impacts (as benefits and costs) of reductions in criteria pollutants from vehicle electrification. The pollutants included in the analysis are primary $PM_{2.5}$ and precursors of secondary $PM_{2.5}$, including NO_X, SO_2, NH_3, and VOCs. This analysis considered only tailpipe emissions reductions rather than full lifecycle emissions (such as power plant emissions). The Evaluation Team used the EPA's COBRA tool to evaluate the health benefits associated with the emissions reductions. COBRA estimates county-level monetized benefits for the county where emissions are reduced. The tool also estimates monetized benefits for all counties in the United States (since emissions disperse beyond the source county), although most impacts are felt in nearby counties, and the Team's analysis only examines California counties.

The morbidity-related monetary benefits include avoided lost wages, avoided medical costs, and the money people are willing to pay to avoid an illness or condition, such as a respiratory disease. The monetary benefits associated with mortality are measured by the value of a statistical life associated with premature mortality. COBRA reports both a low and a high impact for mortality, representing the uncertainties in the estimates.

The total value of the health benefits associated with emissions reductions from the SDG&E Schools and Parks program for activated PTD sites is between $21,737 and $28,240. Table 135 shows the health benefits in California broken down by health endpoint.

Table 135. SDG&E Schools and Parks Pilots California Health Benefits for PTD Sites in 2025

Health Endpoint	Change in Incidence (Annual Cases)		Monetary Value (Annual, 2025 Dollars)	
	Low	High	Low	High
Mortality	**0.002**	**0.002**	**$18,802**	**$25,306**
Avoided Medical Care				
Hospitalization, Respiratory	< 0.000	< 0.000	$2	$2
Hospitalization, Cardiovascular	< 0.000	< 0.000	$2	$2
Hospitalization, Other	< 0.000	< 0.000	$4	$4
ER Visits, Respiratory	0.002	0.002	$4	$4
ER Visits, Cardiovascular	< 0.000	< 0.000	$0	$0
Out of Hospital Heart Attacks	< 0.000	< 0.000	$0	$0
Nonfatal Heart Attacks	< 0.000	< 0.000	$23	$23
Stroke	< 0.000	< 0.000	$2	$2
Lung Cancer	< 0.000	< 0.000	$2	$2
Asthma	1.558	1.558	$1,314	$1,314
Hay Fever	0.064	0.064	$74	$74
Lost Productivity				
Minor Restricted Activity Days	0.384	0.384	$49	$49
Work Loss Days	0.065	0.065	$21	$21
School Loss Days	0.821	0.821	$1,436	$1,436
Total Health Effects	-	-	$21,737	$28,240

As part of this analysis, the Evaluation Team also examined health benefits within DACs, which may be disproportionately burdened by sources of pollution (including air pollution from ICE vehicles). Because COBRA estimates effects at only the county level, the Evaluation Team disaggregated health benefits by census tract using the relative population of each tract from the most recent ACS. For example, the Team allocated 10% of the value of the health benefits to a census tract with 10% of the county's population. The Evaluation Team then estimated the total benefits allocated to DACs and non-DACs.[147] This approach assumes that the benefits of emissions reductions are distributed evenly throughout the county. If the

[147] DAC census tracts are defined as those included in the SB 535 Disadvantaged Communities List (2022), which includes DAC categories for CalEnviroScreen 4.0 Top 25%, CalEnviroScreen 4.0 High Pollution Burden Score and Low Population Count, and 2017 Disadvantaged Community (CalEnviroScreen 3.0 only).

sites reside in DACs, and the emissions reductions are greater in the tracts near the sites, this approach understates the potential benefit to DACs. Additional information about emissions dispersion within counties would provide more precise estimates of health benefits to DACs and non-DACs.

In the Team's analysis, San Diego County had 54% of the total benefits, followed by Riverside County (20%), Los Angeles County (8%), Orange County (8%), and San Bernardino County (6%). Overall, 15% of the total benefits are in DACs.

Highlights

- Cumulative health benefit estimates in California in terms of monetary benefits produced by the Schools and Parks sites range from $21,737 for the low estimate and $28,240 for the high estimate.
- San Diego County had the highest share of health benefits, with 54% of the total benefits, followed by Riverside County (20%), Los Angeles County (8%), Orange County (7%), and San Bernardino County (6%).
- Overall, 15% of the health benefits are in DACs.

Utility Insights

In addition to monthly check-in calls with key SDG&E staff to discuss the status of the Schools and Parks Pilots, the Evaluation Team conducted a close-out interview with SDG&E staff in February 2026 to review overall pilot challenges and successes in 2025. The following section presents challenges and successes that apply to both pilots, followed by those that apply to only one or the other.

Schools Pilot and Parks Pilot

Starting in 2021 SDG&E staff reported that site construction costs were higher than anticipated. These costs were compounded by labor constraints, higher material costs than originally anticipated in 2018 (when the pilots' funding caps were established), and permitting changes. Several years into implementation, pilot staff have learned to deal with the reality of increased costs when planning; however, these costs continue to strain program budgets:

- **Changes in Permitting**. Continuing from previous evaluation years, in 2025 SDG&E staff said that updated permitting requirements and ADA-related upgrades have continued to complicate the construction process and increase program costs. As in previous years, these varying jurisdiction-specific parameters have led to permitting delays and increased administrative burdens. Although the ADA requirements were less robust for Parks Pilot sites than for Schools Pilot sites, the lack of consistency across park jurisdictions has made accurately anticipating costs a challenge for the program. In 2025, SDG&E staff also reported that inconsistencies with third-party DSA inspection standards specifically for Schools Pilot sites led to permitting delays.

Schools Pilot

SDG&E staff noted several other challenges specifically relating to the Schools Pilot, including issues with commissioning and vandalism:

- **Commissioning Delays**. In 2025, SDG&E staff reported some challenges with EVSE vendor staff turnover, which delayed the commissioning process for multiple sites. These delays extended the commissioning process beyond initial expectations for some sites. Throughout the year, SDG&E worked to identify a consistent point of contact to manage the commissioning of Schools Pilot sites. Despite the delays, all sites were completed in 2025.
- **Site Damage.** SDG&E staff reported several instances of vandalism at Schools Pilot sites in 2025, as well as some weather damage in remote areas. Although staff noted that the incidents were not particularly impactful to the sites, did not strain the Schools Pilot budget, and were quickly resolved, vandalism and weather damage issues remain on program staff's radar as the Schools Pilot moves into the long-term monitoring and maintenance stage.

Despite these challenges, SDG&E staff reported success in completing the remaining Schools Pilot sites and continuing to engage stakeholders:

- **Final Sites Completed.** In 2025, SDG&E successfully completed and energized the final seven Schools Pilot sites, bringing the total to 26 sites. With the Schools Pilot moving into the close-out stage, SDG&E took steps in 2025 to prepare for the sunsetting process, which is planned to begin in 2026.
- **Streamlined Material Ordering.** To combat supply chain challenges faced in previous years, in 2025 SDG&E developed and implemented a streamlined material-ordering process to ensure that all materials and equipment are readily available to sites and that the Schools Pilot's funds are utilized effectively.
- **Strong Relationships and Trust.** Over the years of implementing the Schools Pilot, SDG&E staff have built strong, mutually beneficial relationships with school districts and have received positive feedback from staff of participating schools, with some expressing interest in additional sites. The districts have often helped SDG&E find the correct decision-makers to address permitting issues and serve as cheerleaders for the pilot. In 2025, SDG&E continued to receive positive feedback from school districts, and program staff reported that the chargers are well utilized.
- **Continuing Permitting Conversations.** Despite some challenges with permitting for the remaining sites, SDG&E staff remained consistent in their communication with the DSA and inspectors to ensure that the permits were completed correctly and efficiently. By continuing to proactively communicate and follow up with the DSA, SDG&E was able to advance the permitting process and complete the final sites for the Schools Pilot in 2025.
- **Dedicated Construction Crews.** Since site construction started for the Schools Pilot, SDG&E has repeatedly used the same specific crews from construction contractors. In 2025 as in 2024, SDG&E staff observed that the dedicated construction crews have developed extensive site-building experience, which both accelerated the construction of the civil engineering components of sites and enabled all stakeholders to work together more efficiently, contributing to the successful completion of the Schools Pilot.

- **Expanded Interest in EVs.** SDG&E staff said that several K–12 schools that had already completed site installations through the Schools Pilot reached back out to SDG&E hoping to acquire more private (non-public-facing) Utility-owned EVSE infrastructure. School staff noted that they are seeing an increase in charger usage—not just from existing staff who purchased EVs since the chargers were installed, but also from new hires that were attracted to the district in part because of the availability of charging. In addition, previous participants have been actively recommending the Schools Pilot to staff at other schools, which SDG&E staff cited as being especially effective at gaining traction within the same school district. In 2025, SDG&E staff noted that some site hosts have observed shifts in vehicle purchasing and are particularly enthusiastic about the chargers attracting a younger audience. These trends have led site hosts to express interest in transitioning to hybrid or EV entirely and changing or expanding their chargers.

Parks Pilot

In previous evaluation years, SDG&E's Parks program experienced delays at the state level due to drawn out negotiations over the MPA between SDG&E's and the DPR's legal teams about which parties would assume responsibility for costs, liabilities, and risks. The MPA was approved in 2024 and signed in April 2025. With the MPA executed, SDG&E began to plan sites and start the permitting process. SDG&E staff reported one key challenge related to the site planning process:

- **Coordination with State and Local Parks.** SDG&E staff noted that staff turnover at the state level, as well as inconsistencies with permitting requirements across the three Parks districts, has delayed the permitting process for the State Parks sites. At the end of 2025, SDG&E was still working through the permitting process. Staff anticipate receiving the necessary permits by the May 2026 deadline but said that the timeline is still unclear.

Despite the challenges with the permitting process, SDG&E staff reported success with executing the MPA in 2025:

- **Execution of the MPA.** After several years of negotiations, SDG&E was able to finalize and execute the MPA with the DPR in 2025. Staff noted that having an executed MPA has given the Parks Pilot additional momentum as it moves closer to construction of the State Parks sites.

SDG&E's unique experience serving local parks[148] through the Parks Pilot has already been successful in that this effort allowed SDG&E staff to foster committed, positive, long-term relationships with local customers and move toward sunsetting the Parks Pilot:

- **Opportunities for Further Engagement.** As in previous years, SDG&E staff reported that trusted relationships have continued to allow them help customers fast-track sites (both EV and non-EV) that require SDG&E's approval, insight, or support, further strengthening the relationship beyond the Parks Pilot. Additionally, by maintaining a positive reputation through its performance at these sites, in 2025 SDG&E continued to receive interest from municipalities in non-DAC territories and other entities not included in the Pilot, signaling opportunities for future programs.

[148] Local parks are defined as city or county parks.

- **Reduced Vandalism.** In previous evaluation years, SDG&E staff reported issues of vandalism, which impacted the use of chargers and strained the program's budget. However, in 2025, staff surmised that as more people use the chargers and become more comfortable with the technology, they tend to respect them more, which has led to fewer instances of vandalism in 2025 than in previous years.
- **Sunsetting Activities.** In 2025, program staff began the sunsetting process as the Parks Pilot moves toward completion. Activities included closing out the completed sites, moving the technology to internal management, and completing the financials for those sites.

Highlights

- **Schools and Parks Pilots:** Similar to previous evaluation years, site costs continued to be a challenge in 2025. In particular, rising equipment and material costs, decreasing availability of infrastructure, and increased permitting costs have strained the program's budget.
- **Schools Pilot:** SDG&E has successfully built strong relationships with school districts, which has led to the site hosts supporting SDG&E through the permitting process and sharing the success of the program with other districts. This outreach helped generate additional interest in EV offerings through SDG&E.
- **Schools Pilot:** Having dedicated construction crews working on Schools sites has allowed SDG&E and its contractors to become experts, leading to quick construction of the civil components of the sites.
- **Parks Pilot:** Although multiorganizational coordination remained a challenge, ultimately, SDG&E was able to execute the MPA in 2025 and begin the site planning process for the final Parks Pilot sites. Program staff have continued to work with district staff at the selected sites to ensure that they remain engaged.
- **Parks Pilot**: By maintaining strong customer relationships and a positive reputation across its local park sites, SDG&E continued to receive interest from municipalities and other entities not included in the Parks Pilot in 2025, signaling opportunities for future programs.

6.2.3. Lessons Learned

Schools and Parks Pilots

Although SDG&E staff made meaningful progress toward meeting the Schools Pilot's goals through new construction, the Parks Pilot remained unchanged, and neither pilot secured additional contracts. In EY2025, SDG&E completed construction and activated seven additional Schools Pilot sites, bringing the total number of activated sites to 26. No additional contracts were signed in EY2025. The utility also deployed 55 additional L2 charging ports at the seven sites, increasing the total number of installed ports to 227 (220 L2 ports and seven DCFC ports). The 26 activated sites represent 87% of the pilot's per se reasonableness goal of 30 sites. The 220 L2 ports meet 100% of the pilot's per se reasonableness goal of 184 L2 charging ports. The seven DCFC ports meet 58% of the pilot's per se reasonableness goal of 12 DCFC ports. Fifty percent of Schools Pilot sites are in DACs, exceeding the pilot's DAC metric of 40%.

SDG&E did not complete construction or activate any Parks Pilot sites in EY2025. As a result, the total number of charging ports installed in the Parks Pilot remains 90 (82 L2 ports and eight DCFC ports), across 11 activated sites. The 11 activated sites represent 50% of the pilot's per se reasonableness goal of 22 sites. The 82 L2 ports meet 50% of the pilot's per se reasonableness goal of 164 L2 charging ports. The eight DCFC ports meet 62% of the pilot's per se reasonableness goal of 13 DCFC ports. Ninety-one percent of Parks Pilot sites are located in DACs.

No additional contracts were signed for either pilot in EY2025. The total contracts signed for the duration of the pilot is 27 for the Schools Pilot and 11 for the Parks Pilot, unchanged from EY2024.

Despite continued site cost and permitting challenges, program staff worked to mitigate costs and secure sites through active coordination. SDG&E launched the Schools and Parks Pilots during the COVID-19 pandemic, a period marked by unprecedented economic disruption across nearly every market. As a result, the cost estimates used in Decision 19-11-017, which established the pilots and their funding levels, no longer reflected actual implementation costs.

As in prior evaluation years, Schools and Parks Pilots site development continued to face cost and schedule pressures in 2025. Key challenges included rising labor and material costs. supply chain delays, updated permitting requirements and ADA-related upgrades, jurisdiction-specific permitting processes that increased administrative burden and delayed approvals, and inconsistent third-party DSA inspection standards for Schools Pilot sites, which contributed to further permitting delays.

To address supply chain issues identified in earlier years, SDG&E developed and implemented a streamlined material-ordering process in 2025 to help ensure that materials and equipment would be available when needed and that Schools Pilot funds were used efficiently.

Although permitting challenges remained for the final sites, SDG&E maintained regular communication with the DSA and site inspectors to help ensure that permits were completed accurately and efficiently. Through this proactive coordination and follow-up, SDG&E advanced the permitting process and completed the remaining Schools Pilot sites in 2025.

SDG&E Schools and Parks Pilots continued to successfully promote regional EV adoption. In 2025, the Schools and Parks Pilots increased the number of operational sites by seven and zero respectively to bring the total to 26 and 11 for the pilots to date. The Schools and Parks Pilots contributed to the adoption of 150 and 41 EVs, respectively in the pilots to date for households neighboring the infrastructure.

The Schools and Parks Pilots sites are helping to displace petroleum, reduce GHG and local emissions, and achieve nominal health impacts overall and within DACs. The SDG&E Schools and Parks Pilots sites have displaced over 229,561 gallons of petroleum to date, with 70% of the impact within DACs. Since their inception the pilots have resulted in an 83% reduction of GHG, with 69% of the impact and 15% of the health benefits in DACs, and total monetized health benefits ranging from $21,737 to $28,240. These sites all positively contributed to lowering local emissions, with CO reduction showing the most prominent projected reductions of more than 21,000 kg over a ten-year period.

Schools Pilot

Utilization of Schools Pilot sites is rising, with a growing number of sessions and increases in total consumption and demand. Seven new sites were activated in the SDG&E Schools Pilot in 2025, adding a total of 288 kW of new installed capacity in EY2025, bringing total installed capacity to 1,790 kW in the program to date. Overall, energy consumption increased by 48%, rising to 656 MWh in EY2025, up from 450 MWh in EY2024. Nearly 70,000 charging sessions have taken place in the pilot to date, with approximately 30,000 sessions occurring in EY2025. Monthly energy consumption rose steadily throughout EY2025, from approximately 45 MWh in January to 85 MWh at the end of the year, with dips in consumption in the summer months, coinciding with breaks in the school year. The amount of energy consumed per charging session has increased year over year, with 29% of charging sessions dispensing over 25 kWh, upon from 22% in EY2024. Demand peaked at 483 kW in EY2025, up from 381 kW in EY2024. Charging activity outside of school hours at some sites, including on the weekends, indicates that sites are supporting the local community in addition to school employees.

Parks Pilot

With the MPA signed in April 2025, the Parks Pilot has moved beyond the extended negotiation phase and into site planning. However, differing permitting requirements across the three Parks districts have continued to delay the construction timeline. The original 2021 plan called for the utilities to enter into a collective participation agreement with the DPR. Over time, however, the utilities determined that their program needs were distinct, which led each utility to pursue a separate MPA. SDG&E continued negotiating the terms of its MPA throughout 2022, 2023, and 2024. In 2024, SDG&E and DPR legal teams approved the agreement language, and the MPA was fully executed in April 2025. After the MPA was executed, SDG&E began site planning and initiated the permitting process; however, permitting has been delayed by state-level staff turnover and inconsistent requirements across the three Parks districts. Currently, staff expect to receive permits in May 2026.

Despite these delays, finalizing the MPA after several years of negotiations marked a significant milestone. Staff noted that the executed agreement has given the Parks Pilot additional momentum as it moves closer to construction at the State Parks sites.

Utilization of Parks Pilot sites is rising, with a growing number of sessions and increases in total consumption and demand. While no need sites were activated in EY2025, energy consumption grew by nearly 20%, rising from 480 MWh in EY2024 to 570 MWh in EY2025. Nearly 65,000 charging sessions have taken place in the pilot to date, with approximately 22,000 of sessions occurring in EY2025. Monthly energy consumption rose steadily throughout EY2025, from approximately 40 MWh in January to 60 MWh at the end of the year, The amount of energy consumed per charging session has increased year over year, with 22% of L2 charging sessions dispensing over 25 kWh, up from 14% in EY2024, and 14% of DCFC sessions dispensing over 50 kWh, up from 10% in EY2024. Some Parks Pilot sites show significant overnight usage, which may mean they are supporting EV drivers in nearby multi-unit dwellings.

7. Liberty Utilities Transportation Electrification Programs

7.1. Schools and Parks Pilots

7.1.1. Overview

This overview provides a detailed description of the Liberty Schools and Parks Pilots; summarizes the pilot implementation process, materials review, performance metrics, and budget; and provides a timeline of major milestones. Following the overview are detailed findings, highlights, and lessons learned.

Pilot Description

Schools Pilot: Through its Schools Pilot, Liberty aims to increase access to available charging at schools and educational facilities throughout its service territory. Liberty provides charging infrastructure to support electric school buses and light-duty charging for parents, teachers, and students. At the time of Decision 19-11-017, Liberty had identified 17 potential sites, with 15 at K–12 schools, one at Lake Tahoe Community College, and one (a bus barn) for the Lake Tahoe School District. There are no DAC requirements for the Liberty Pilots, as there are no CES 4.0–defined DACs in the service territory.[149] Per Decision 19-11-017, Liberty plans to install 56 L2 charging ports and two DCFCs across all sites.[150] Liberty's ownership model for all charging stations in the Schools Pilot covers the cost of EVSE, network software, transformers, permitting, electrical work, and trenching. Liberty also installs safety bollards and snow melt and lighting equipment, where appropriate.

Schools Pilot Target

56 L2 and two DCFC charging stations.

Schools Pilot Design Goal

Enable schools to offer public charging to staff, students, parents, and the greater community.

Parks Pilot: Because the Tahoe region is a destination for many nonresidents, Liberty staff designed the Parks Pilot to increase access to available charging at state parks throughout its service territory for park staff and visitors. Prior to Decision 19-11-017, Liberty staff worked with parks staff to determine the optimal locations for EVSE by considering both the needs of the parks and their proximity to town and regional centers, retail centers, beaches, recreation areas, education

Parks Pilot Target

Five dual-port pedestal EVSE at three sites.

Parks Pilot Design Goal

Encourage staff at state parks and beaches to charge their own EV fleets and offer charging to staff and patrons with LDVs.

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149 The bus barn for Lake Tahoe School District is included in the Schools Pilot as a part of Liberty's goal to replace 50% of the district's diesel bus fleet (as of 2019) with electric school buses.

150 To meet the overall desired timeline for the project, Liberty's cutoff date for accepting applications for the Schools Pilot was April 29, 2024. Ultimately, Liberty secured participation agreements with three schools and is planning to install three chargers (two L2 and one DCFC) at the remaining two sites. As of February 2026, these sites were still in design.

facilities, and large marinas. Through the Parks Pilot, Liberty planned to install five dual-port pedestal EVSE at three California park locations. Similar to the Schools Pilot, Liberty's ownership model for all charging stations covers the cost of EVSE, networking software, transformers, permitting, electrical work, and trenching.

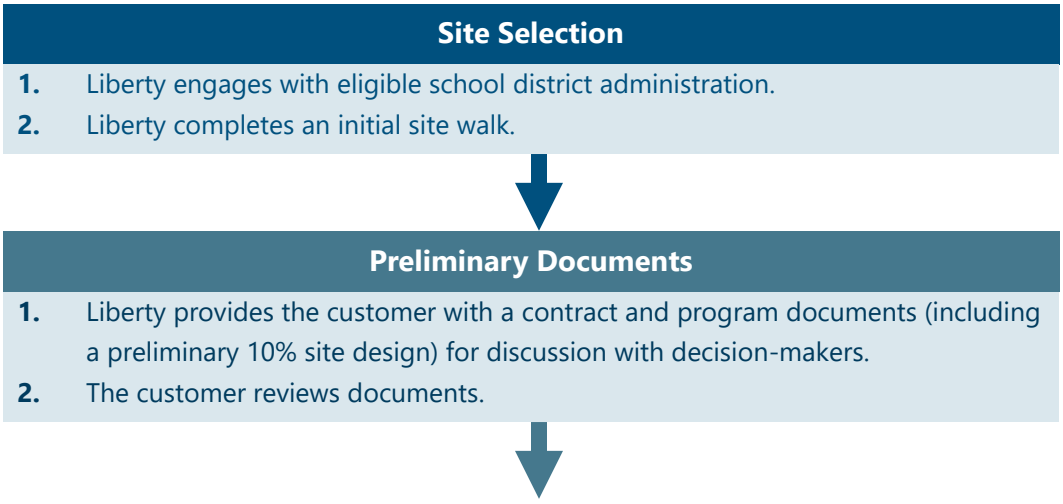
Liberty designed both pilots to help meet the growing demand for EV charging from residents and visitors to the Lake Tahoe region. Through these pilots, Liberty will increase the share of EV miles traveled in the Tahoe region, which supports the community's sustainability and environmental improvement objectives, including reducing GHG and criteria air pollutant emissions.

Implementation

Liberty staff began site recruitment in 2019 in preparation for Decision 19-11-017 by directly engaging with potential sites prior to filing AB1082-3. From 2021 through 2023, staff focused their efforts on cultivating interest in site construction from schools and parks personnel. In EY2024, Liberty completed all recruitment for the Schools Pilot, securing two additional sites. The Utility is planning to install one site through the Parks Pilot. [151]

Figure 324 describes Liberty's implementation process for the Schools Pilot, and Figure 325 describes the implementation process for the Parks Pilot.

Figure 324. Liberty Schools Pilot Implementation Process



[151] To meet the overall desired timeline and budget for the project, Liberty expects to have one site for the Parks program. As of February 2026, Liberty plans to finalize the number of sites and secure site-specific addendum agreement(s) after the Utility signs the MPA with the State Parks Department.

Participation Agreement

1. Liberty and the customer execute the Participation Agreement based on the preliminary design.

Contractor and Equipment Selection

1. Liberty develops an RFP for procurement of hardware and software and for electrical and construction work.
2. Liberty selects a contractor and equipment for site construction.

Final Design and Permitting

1. Liberty and the customer finalize site designs.
2. Liberty submits requests for and acquires permits.

Construction and Energization

1. The site is constructed and energized.
2. Liberty owns, operates, and maintains the charging stations for a term of eight years.

Figure 325. Liberty Parks Pilot Implementation Process

Site Selection

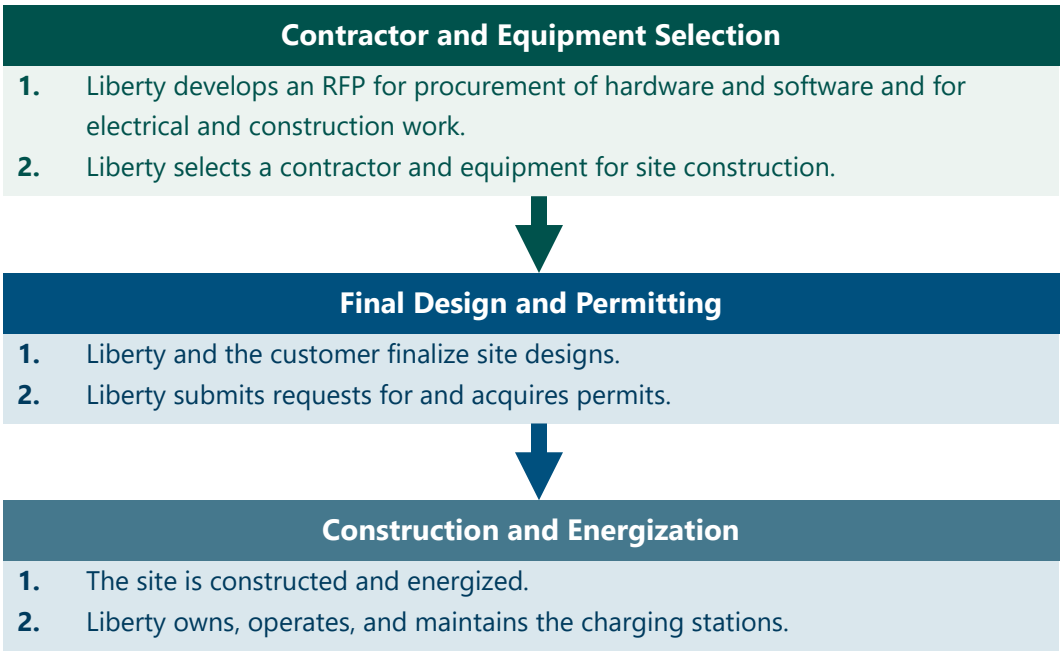
1. Liberty engages with eligible Parks district.
2. Liberty completes an initial site walk.

Preliminary Documents

1. Liberty provides a contract and program documents for discussion with decision-makers.
2. The customer reviews documents.

Participation Agreement

1. Liberty and the State Parks Department develop and execute the MPA.



Pilot Materials Summary

Liberty did not develop any new program materials in 2025.

Pilot Performance Metrics

As of December 31, 2025, Liberty had one operational site with eight L2 ports and had secured two additional sites for the Schools Pilot. Construction for these sites was initially expected to begin in 2025 but was delayed to 2026. The first site is configured with a single L2 port, and the second site has plans to install six L2 ports and a low-power DCFC port.

No Parks Pilot sites were secured in EY2025.

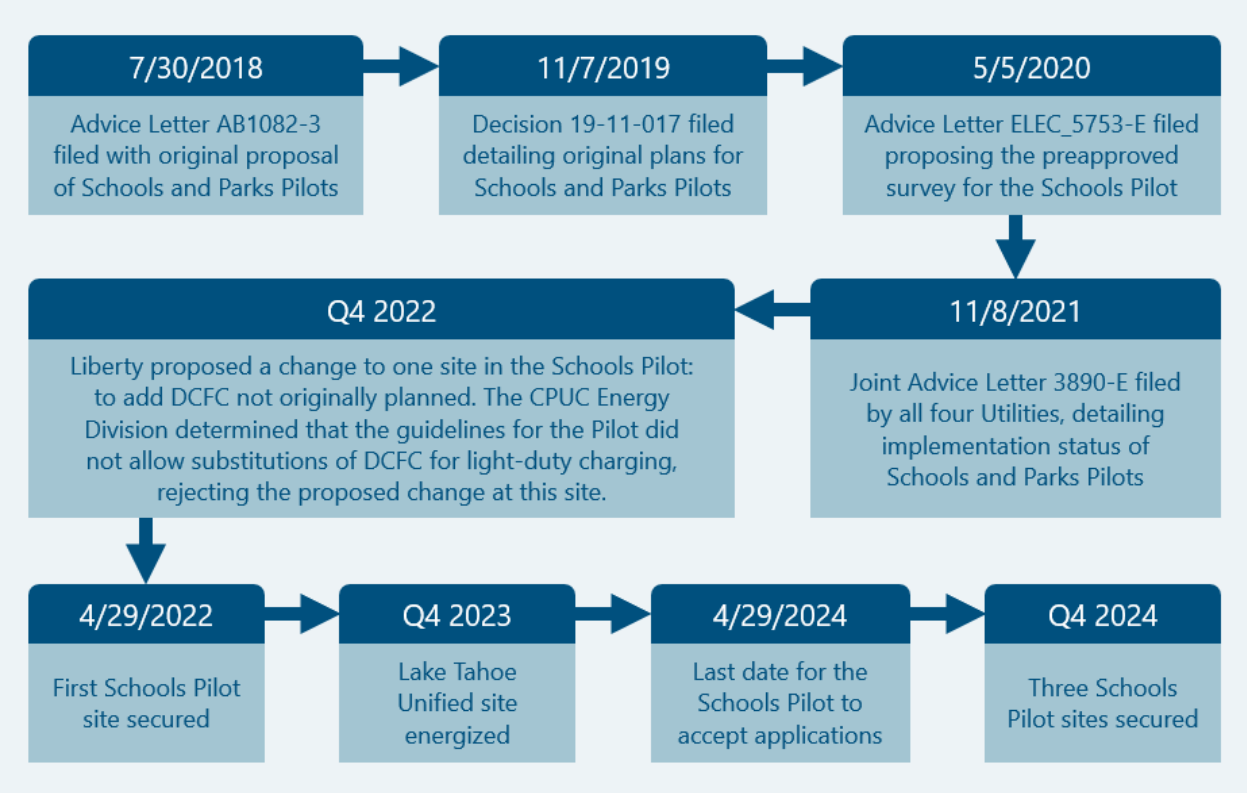
Budget Summary

Through the end of 2025, Liberty had spent $308,180 of $3.9 million on the Schools Pilot and has spent none of the approved $0.78 million Parks Pilot funds.

Timeline

Since the beginning of the Schools and Parks Pilots, Liberty has filed three Advice Letters: one pertaining to the Schools Pilot and two to both the Schools and Parks Pilots. In 2023, the Lake Tahoe Unified site was energized. In the second quarter of EY2024, Lake Tahoe Community College signed an agreement for one DCFC site and one L2 charging site, and the Colville district signed a contract to install one L2 bus charger. Figure 326 shows all major milestones since the pilots' inceptions.

Figure 326. Liberty Schools and Parks Pilots Key Milestones



7.1.2. Findings

As discussed in the *Overview* section, Liberty has one operational Schools Pilot site that was activated in early EY2024, and no new sites were activated in EY2025. The Parks Pilot had no activated or operational sites in 2025. This section provides findings from the Utility staff interviews, site visits, grid impacts, petroleum displacement and GHG and criteria pollutant reductions.

Site Visits

The Evaluation Team visited the single completed Schools Pilot site soon after it was completed in EY2024. The site is part of a large complex including a middle school, the district office, and transportation facility. Eight single-port L2 EVSE were installed at the site inside the bus barn to support charging the school bus fleet. The site included a new utility service with a new transformer, meter pedestal, and main switchgear located at the edge of the public right of way and under the overhead distribution lines as shown in Figure 327.

Figure 327. Liberty Schools Pilot Site Utility Service Equipment



The switchgear had an 800 A main disconnect and was raised off the ground to accommodate snow accumulations. Power was trenched approximately 60 feet from the switchgear to the building, where conduit emerged from the ground and entered the bus depot above the entrance. The charging bays were located in the center of the building and provided clearance to underground diesel storage tanks located at the other end of the building.

Within the building, large conduit runs were hung from the ceiling, with individual circuits branching down interior poles or walls to ground mounted EVSE. The overall design minimized required trenching and used the shortest conduit runs possible for the site layout as shown in Figure 328.

Figure 328. Liberty Schools Pilot Site Conduit Run Down Pole



The ground-mounted EVSE were selected because they offer 80 A capacity and were more easily procured by the school district than other equipment. EVSE that mount directly to the existing roof support posts may have been possible but would have taken additional time and effort to procure without offering significant cost savings or operational benefits. Vehicles park in rows of two between the posts (see Figure 329). This close vehicle spacing likely reflects a building design to support heavy snow load on the building's flat roof.

Figure 329. Liberty Schools Pilot Site Rows for Charging



At the time of the site visits, the district had four EVs: one Type A Microbird and three Type D Blue Birds. The Micro Bird had been in service for more than a year and used one L2 EVSE installed on the regular building electrical service. The district had placed an order for four additional buses from a different manufacturer that were scheduled for delivery in early EY2024. However, the manufacturer was unable to deliver vehicles that matched the order specifications and later declared bankruptcy. This delayed full utilization of the charging stations, but in late 2025 the site's energy use profile showed that all stations were in use.

At the time of the site visit, the EVSE screens were displaying a 50 A power level (11 kW), although staff indicated that this had not been set intentionally and they intended to use the full 80 amps available for each charging port. The vehicles had adequate range for regular usage, including during inclement weather, but needed to be charged midday to have adequate charge for afternoon routes. In addition, the district had not set up load management controls to shift charging from higher cost evening peak periods to low cost overnight periods.

The EVSE has been reliable and adequate even at the lower power level. The district is interested in adding higher-power DCFCs in a future project which would give more flexibility.

Highlights

- The site layout minimized trenching from the new utility service into the building, and overhead conduit used straight runs, minimizing material costs.
- The site had four vehicles ready to charge at time of activation, but additional vehicle deliveries were delayed due to manufacturer issues.
- The district said bus performance and charging reliability have been fine; however, the district is interested in higher-power charging in future sites to provide more flexibility.

Grid Impacts

The Evaluation Team determined grid impacts for the Liberty Schools Pilot based on analysis of energy consumed by operational EVSE installed through the program by the end of 2025, combined with NSP charging session data.

Data Sources

The primary data source used in this section is energy usage data from Utility AMI and NSPs.

Summary of Grid Impacts

Table 136 presents the estimated Schools Pilot program grid impacts.

Table 136. Liberty Schools Pilot Grid Impacts

Impact Parameter	Actual 2025	Actual PTD	10-Year Projection PTD
Operational Sites	0	1	1
Installed Capacity (kW)	0	130	130
Electric Energy Consumption, MWh	115	185	1,593
On-Peak (4 p.m. to 9 p.m.) MWh (and % of total)	45 (40%)	71.4 (38.6%)	N/A
Maximum Demand, kW (with date and time)	125 (10/10/25 10:15 a.m.)	125 (10/10/25 10:15 a.m.)	N/A
Maximum On-Peak Demand, kW (with date and time)	125 (10/10/25 10:15 a.m.)	125 (10/10/25 10:15 a.m.)	N/A

Energy Trends

Consumption and Maximum Demand

Figure 330 depicts two years of energy consumption and maximum demand trends for the single activated school's site. Both consumption and maximum demand have grown slowly over time, with significant variation month-to-month. The site has eight L2 EVSE offering 130 kW of installed capacity. The final two months of the year show maximum demand nearing total installed capacity, which likely indicates that all vehicles in the customer VAP have been delivered and are in operation. Though maximum demand was very similar in November and December, consumption dropped significantly during the holiday periods. In addition, in both EY2024 and EY2025 there were notable drops during the summer months, coincident with the school calendar

Figure 330. Liberty Schools Pilot Monthly Energy Consumption and Maximum Demand

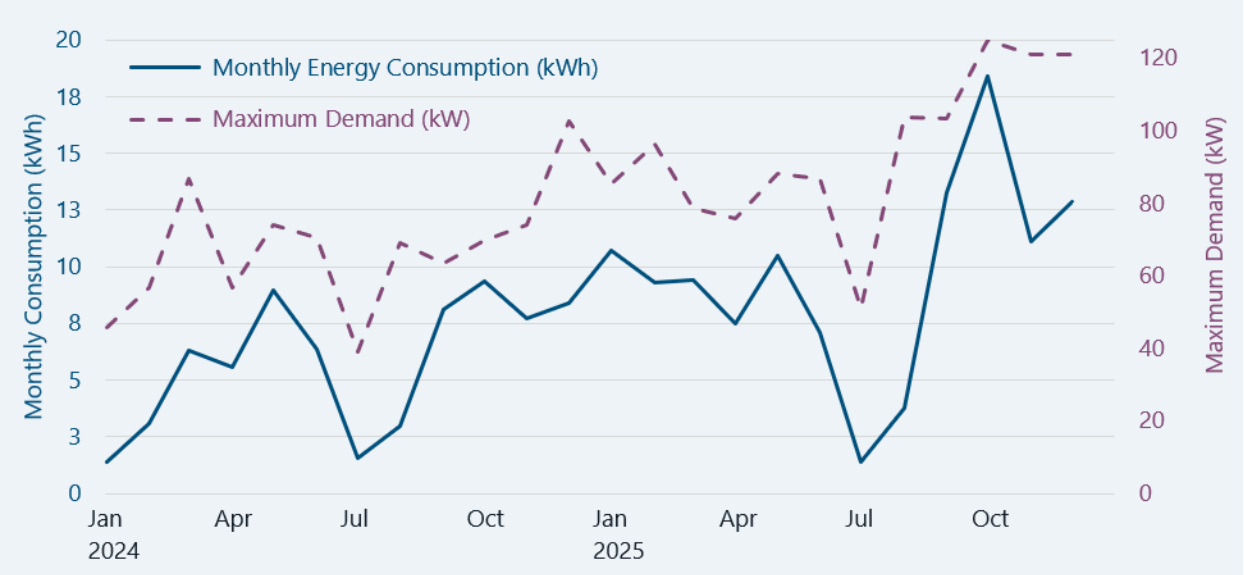


Figure 331 shows lifetime daily energy consumption for the site. The end of 2025 showed increasing daily consumption, approaching 1 MWh at the end of 2025. Weekends show nearly zero consumption, meaning that some weekday overnight charging could be shifted to low cost and low emissions (midday) weekends.

Figure 331. Liberty Schools Pilot Daily Energy Consumption for PTD Sites

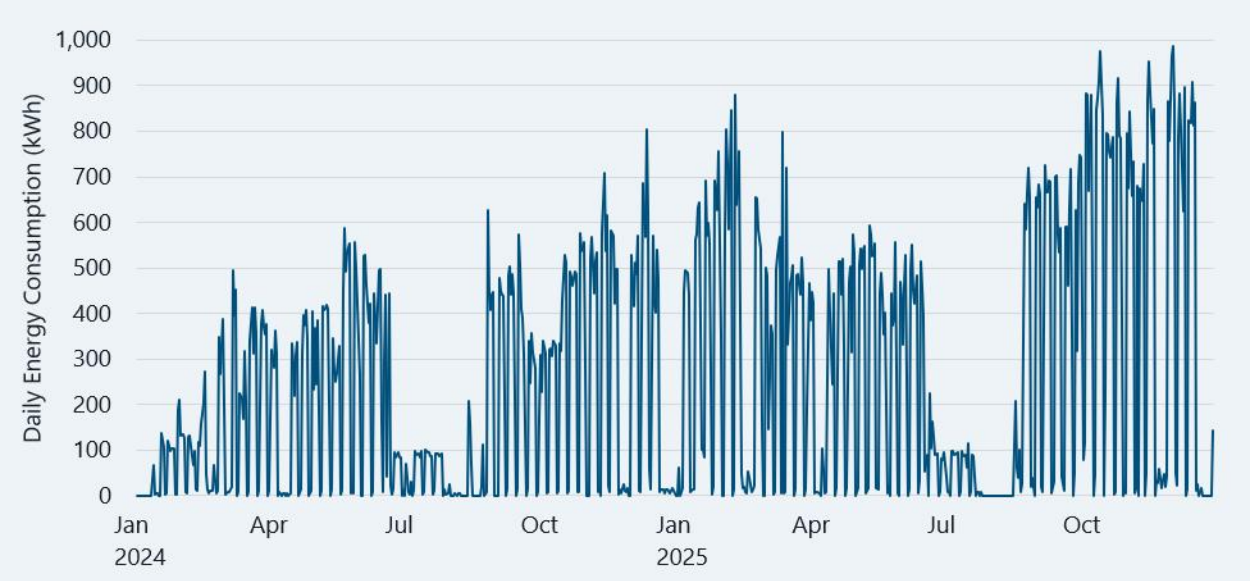


Figure 332 shows maximum daily demand, which has trends closely aligned to those of daily consumption, which the highest maximum daily demand occurring at the end of 2025.

Figure 332. Liberty Schools Pilot Daily Maximum Demand for PTD Sites

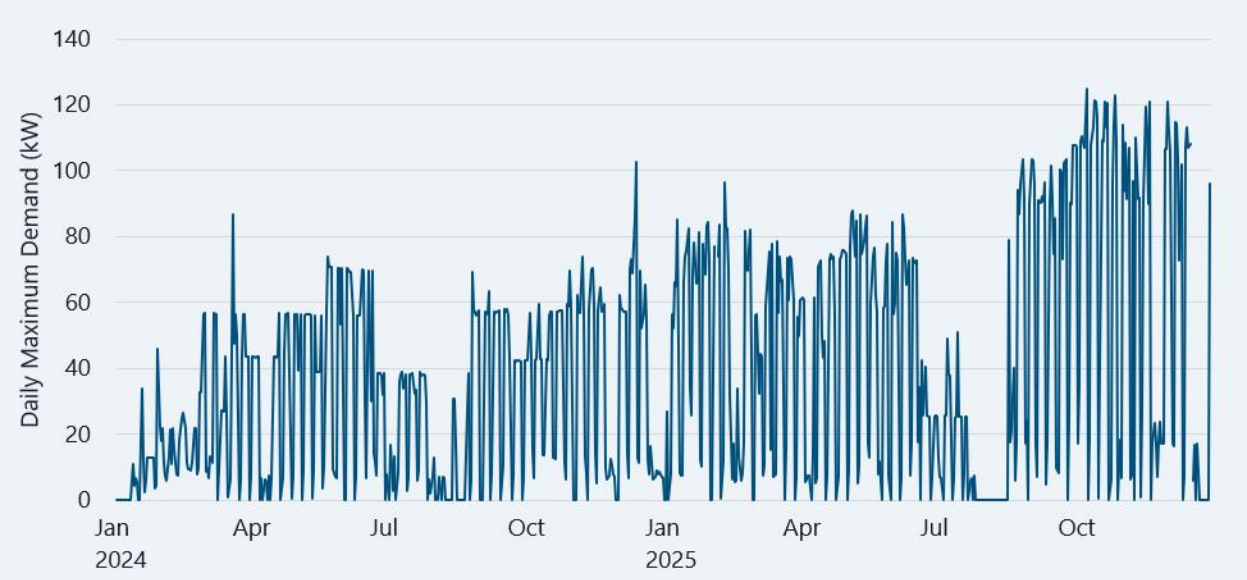
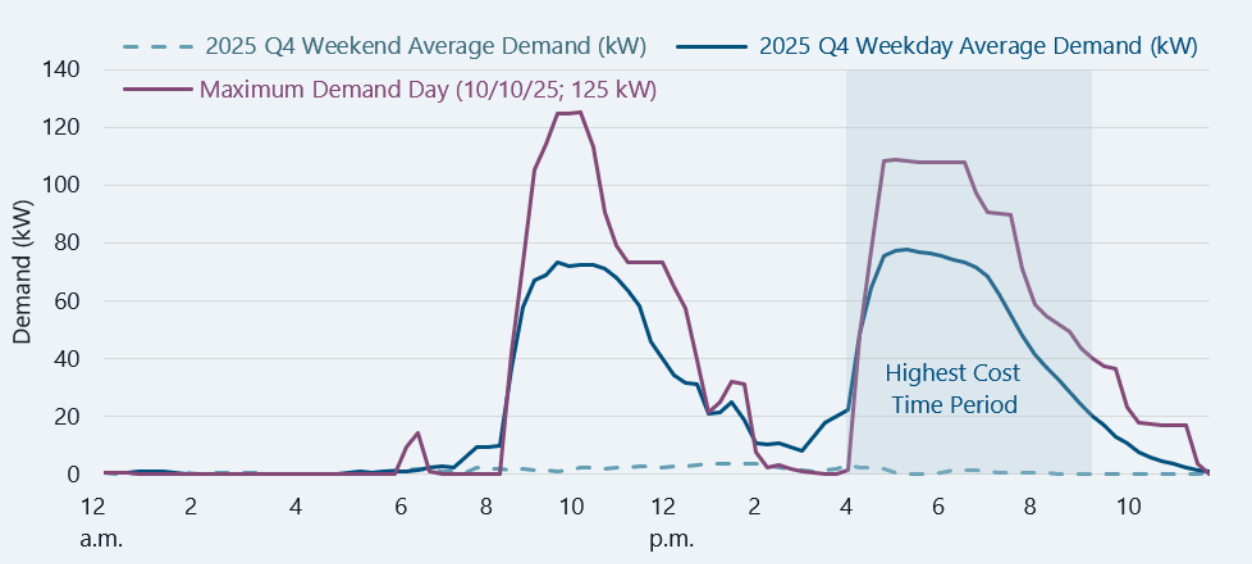


Figure 333 depicts load curves of an average weekday and weekend in the fourth quarter of EY2025 along with the day of highest demand. Weekday charging behavior does not show implementation of load management for school bus charging for morning and afternoon sessions. This charging behavior takes advantage of lowest-cost energy for morning charging sessions, but evening charging sessions take place almost entirely during the 4 p.m. to 9 p.m. highest-cost period. The fleet unnecessarily consumes

approximately 40% of its energy during the highest-cost period which could be shifted to lower-cost overnight charging. This has increased energy costs 20% to 30% per month over the lifetime of the project.

Figure 333. Liberty Schools Pilot Average Weekday and Weekend Q4 EY2025 Load Curves



Load Management and Charging Flexibility Analysis

This section describes considerations around load management and charging flexibility. Load-managed sites adopt techniques to avoid charging vehicles during periods of peak energy prices. Where applicable, load management can also reduce peak demand to mitigate the cost impacts of utility tariff demand-oriented pricing.

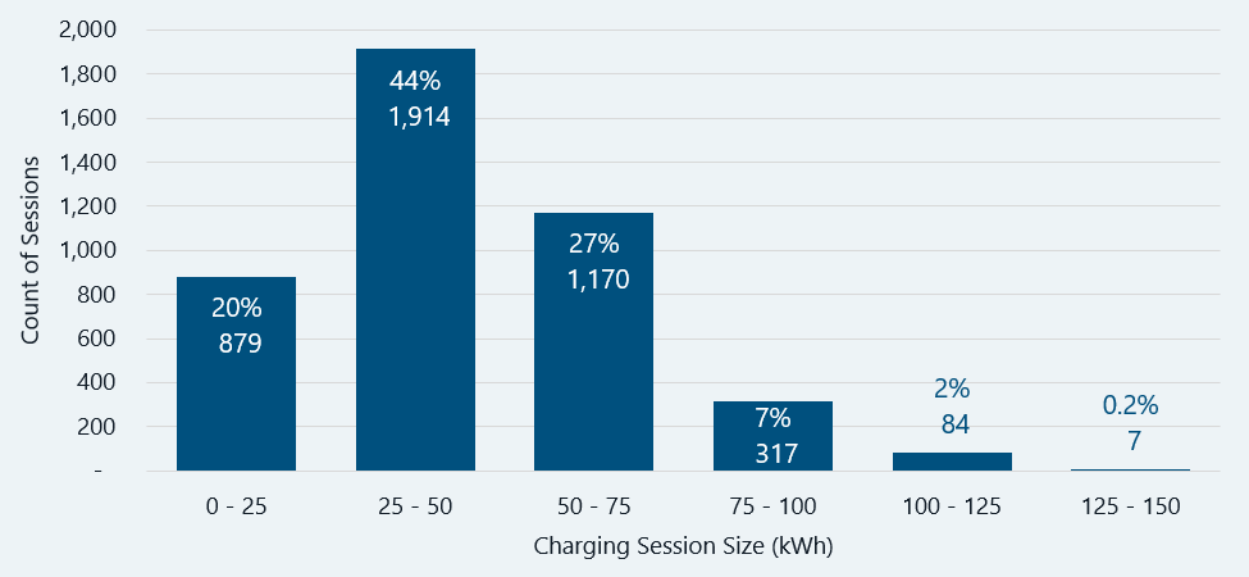
At the time of reporting this site does not have adequate billing data to allow reporting or analysis. However, the Evaluation Team has visited the site and spoken with the operator. This has allowed the Evaluation Team to understand fleet operational needs, installed charging equipment and which NSP serves the site. The NSP used at the site confirmed they offer load management capabilities to fleet customers. Therefore, the Evaluation Team is confident that if load management were used, the fleet could reduce consumption from 4 p.m. to 9 p.m. from approximately 40% to below 15% and reduce peak demand. The Evaluation Team estimated that this would reduce the cost of monthly utility billing by 20% to 30%. For the tariff applicable to this site, energy costs are 15% to 20% higher during the peak period from 4 p.m. to 9 p.m. compared with other periods, and demand charges are $3.00/kW.

Charging Flexibility

At the time the Evaluation Team conducted a site visit the fleet had three small (~100 kWh each) and one large (130 kWh) Bluebird school buses. Recent NSP data shows that the fleet is conducting 15 to 20 charging sessions daily, which indicates that additional vehicles have been delivered. To better understand the fleet's operations, Figure 334 looks at frequency of charging session sizes by kilowatt-hours consumed. Two-thirds of sessions have consumption that is less than 50% of bus battery capacity. Less than 3% of charging sessions are over 100 kWh (likely limited to the larger buses), which would represent

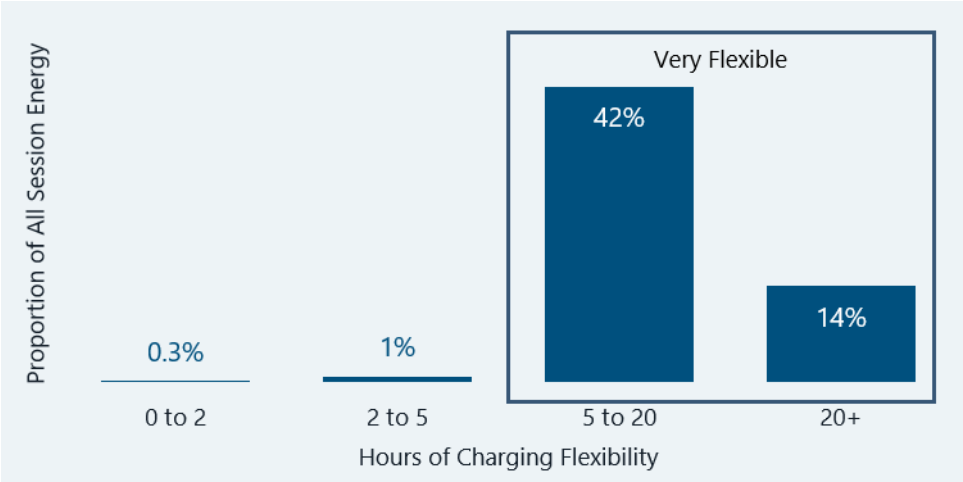
80% of battery capacity. The significant portion of charging sessions below 50 kWh indicates substantial energy-based charging flexibility.

Figure 334. Liberty Schools Pilot Charging Session Count by Consumption Size



The Evaluation Team used site charging data to determine the amount of time vehicles are connected to a charging port but not actively consuming energy. This allowed the Team to assess time-based charging flexibility, or the ability for a vehicle to shift charging from periods of high-cost electricity to periods of low-cost electricity without impacting vehicle operations. NSP data shows that over 55% of charging sessions are between 4 p.m. to 9 p.m. (Figure 335), only slightly higher than the proportion of energy consumed then (40%). Nearly all of those overlapping sessions had more than adequate flexibility of over five hours to completely avoid the higher energy. The large charging flexibility also means charging power and speed can be slowed down significantly, potentially by more than half.

Figure 335. Liberty Schools Pilot Charging Flexibility for PTD Sites in Sessions Overlapping the Time Period Between 4 p.m. and 9 p.m.



Potential Benefits of Load Management

The Evaluation Team analyzed charging session data to estimate the value of optimal load management, considering each site's observed operating patterns and potential ability to shift vehicle charging loads. This analysis included the one operational Liberty Schools Pilot site.

The Evaluation Team developed and executed an optimization routine that reviews daily charging behavior at the site and shifts energy consumption from the peak time period to lower-cost periods of the day with both unused charging capacity and vehicle charging availability. The Team used NSP charging session data to ascertain how many vehicles had been plugged in and how many kilowatt-hours of energy could have been shifted during each time period. For hours in the same TOU rate period, the Team used carbon intensity of the electric grid (evaluated from CAISO 2025 GHG emissions factors) and BAU charging load as tiebreakers to determine vehicle charging priorities. The optimization algorithm also incorporates monthly demand charges from vehicle charging and minimizes the site's total charging costs in the optimization. The Team calculated the resulting costs and GHG emissions for the load-shifted case and compared the results to the BAU case to determine cost-reduction and GHG-reduction potential. Results of this analysis should be viewed with the following context:

- This analysis considers the volumetric (cost per kilowatt-hour) component of the site's electricity costs as well as any demand charges that may apply under the Utility's rate structure. Optimal load management has the potential to also reduce demand charge subscriptions, which could impact costs substantially in lower-volume months. The cost-minimization approach developed in this analysis minimizes the total monthly cost (energy consumption plus demand charges), which allows for an increase in monthly peak demand as long as any applicable demand charges for increased demand are more than offset by cost savings resulting from load shifting to less expensive TOU time periods. In most cases, monthly peak demand either stayed the same with load shifting, having no impact on costs, or decreased, resulting in additional cost savings.
- These results reflect only the portion of the site's vehicle fleet that was electrified in EY2025. A fully electrified fleet would see higher cost reduction potential from load management.
- This analysis considers the cost-saving potential of load management but does not consider the potential of load management to generate revenue via LCFS Smart Charging credits.
- This analysis examined actual charging behavior at the site (using actual recorded plug-in and unplug times) to determine charging opportunities and does not account for other operational or scheduling improvements for charging electrified fleets, which could enable more-effective load management, resulting in higher potential cost reduction.

Table 137 provides these results for the one operational Liberty Schools Pilot site. Overall, optimizing load shifting to minimize charging costs could reduce the site's energy consumption costs by 43.0% with an increase in attributed electricity grid GHG emissions of 45.8%. Load shifting to minimize GHG emissions could achieve GHG emissions reductions of 18.4%, but these reductions would come with lower cost savings of 12.3%.

Table 137. Liberty Schools Pilot Site Potential Cost and Attributed GHG Emissions Reductions

	School Bus Site
2025 Total Number of Fleets	**1**
2025 Total Operating Days	**364**
Cost-Minimization Load-Shifting	
Cost Reduction Potential ($)	20,400
GHG Reduction Potential (kg CO_2e)	-6,240
Cost Reduction Potential (%)	43.0%
GHG Reduction Potential (%)	-45.8%
GHG-Minimization Load-Shifting	
Cost Reduction Potential ($)	5,800
GHG Reduction Potential (kg CO_2e)	2,510
Cost Reduction Potential (%)	12.3%
GHG Reduction Potential (%)	18.4%

Highlights

- The site in the Schools Pilot reached total consumption of 115 MWh in EY2025, bringing the total to 185 MWh over its two years of operation.
- The charging patterns for this site align with those of typical school bus operators that do not use load management and charge in the morning and afternoon resulting in unnecessary high-cost charging.
- Analysis of NSP data suggests that the 40% of total energy consumption occurring from 4 p.m. to 9 p.m. could be shifted almost entirely to lower-cost and lower-emissions periods. Charging more slowly would also mitigate demand-oriented costs.
- Charging sessions show that the school buses typically use less than half of their battery capacity. This means that buses could run longer routes between charges to avoid charging during peak periods, or charge management could be implemented to control when the buses charge to avoid higher-cost periods, which would lower monthly utility bills in the future.

Petroleum Displacement

The Evaluation Team estimated petroleum displacement from the one operational Liberty Schools Pilot site using three key pieces of information: electricity used for vehicle charging, EV annual miles traveled, and annual counterfactual vehicle fuel consumption. Table 138 presents petroleum displacement impacts for the Liberty Pilot site through 2025, including estimated actual impacts for 2025, actual impacts for all sites in the pilot to date, and a 10-year forecast.

Table 138. Liberty Schools Pilot Petroleum Displacement Summary, PTD Sites

	Usage (n=1)				Petroleum Displacement (DGE)		
	2025 Actual [a] (kWh)	PTD Actual [b] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
School 1	115,290	185,162	89,594	143.58	9,757	15,671	134,742

[a] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.
[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Highlights

- The one operational site achieved an impact of over 15,000 gallons of diesel fuel avoided in the pilot to date.
- Over a 10-year period, this site will displace nearly 135,000 gallons of diesel.

Greenhouse Gas and Criteria Pollutant Impact

The Evaluation Team calculated reduced emissions from displaced fossil fuel use from ICE vehicles that were not in service as a result of the Liberty Schools Pilot. The Team first developed one ICE counterfactual, then calculated the emissions associated with this vehicle under conditions that otherwise matched the EVs to provide a baseline. Although EVs have no tailpipe emissions, the fossil-fuel power plants that supply electricity to the vehicle chargers still release some GHGs and criteria pollutants.

Table 139 presents the GHG emissions reductions resulting from the one operational Schools Pilot site in 2025 and the program to date along with a 10-year projection Overall, the Schools Pilot achieved a reduction of 86% of GHG emissions (143 MT total) relative to the counterfactual to date (166 MT, not shown in the table).

Table 139. Liberty Schools Pilot GHG Reductions Summary, PTD Sites

	Usage (n=1)				GHG Reduction (MT)		
	2025 Actual [a] (kWh)	PTD Actual [b] (kWh)	2025 Actual Use (miles)	PTD Actual Use (miles)	2025 Actual	PTD Actual	10-Year Projection
School 1	115,290	185,162	89,594	143.58	89	143	1,299

[a] "2025 Actual" represents the data from all activated sites from program inception for the calendar year 2025.
[b] "PTD Actual" represents the data from all activated sites from program inception for all program years.

Of the local emissions, the Schools Pilot had the highest impact in reducing CO, resulting in an estimated reduction in the pilot to date of 40.8 kg and a projected 10-year reduction of more than 380 kg (Table 140).

Table 140. Liberty Schools Pilot Local Emissions Net Reductions

Emissions	PTD Sites (n=1)	
	Actual	10-Year Projection
PM_{10} (kg)	0.31	3.2
$PM_{2.5}$ (kg)	0.30	3.0
ROG (kg)	1.40	13.9
CO (kg)	40.8	381.3

Highlights

- In EY2025, the Schools Pilot achieved a net GHG emissions reduction of 85 MT.
- Over 20 years, the site is expected to avoid nearly 1,300 MT of CO_2.

Utility Staff Insights

In addition to periodic check-in calls with Liberty staff to discuss the status of the Schools and Parks Pilots, the Evaluation Team conducted a close-out interview with staff in February 2026 to review overall pilot challenges and successes in EY2025. The following sections present these challenges and successes organized by pilot.

Schools and Parks Pilot

In EY2025, Liberty program staff reported that due to continued internal constraints and competing responsibilities, they had been unable to devote significant time and resources to the Schools and Parks Pilots, which contributed to limited activity for the pilots during the year. At the end of EY2025, Liberty was planning to increase its focus on the pilots and bring on additional support for 2026.

Schools Pilot

Just before the application period closed in mid-2024, Liberty staff secured two additional sites for the Schools Pilot. Construction was originally expected to start in 2025 but was delayed to 2026. The first site will have a single-port L2 bus charger. The second site is targeted to have a total of three dual-port L2 chargers, and is the only site approved for lower-power DCFCs, with all of the charging stations available to the public. At the end of 2025, both sites were in the procurement stage, with Liberty staff reporting challenges around procurement and permitting, concerns about timelines and long-term usefulness of the installed chargers, and an ongoing lack of interest from schools in the pilot:

- **Managing Timeline Concerns.** Liberty staff reported that they had expected to start construction for the remaining two sites in 2025, but internal constraints delayed construction. In addition to resource constraints, program staff expressed concerns over the limited window of time, as construction at schools cannot begin until mid-May and must finish by mid-October. Liberty staff hope to be as prepared as possible prior to the construction window to ensure that the final sites are constructed in 2026. Liberty advanced procurement activities in 2025, including developing a preliminary design to guide contractor bids and initiating RFP and RFQ processes for construction and equipment.

- **Procurement and Permitting Challenges.** In 2025, Liberty's procurement team reported challenges managing the permitting requirements set forth by the DSA. The team is mitigating those difficulties while it searches for a contractor for the remaining sites.
- **Concerns over Long-Term Usefulness of Installed Chargers**. Liberty staff reported that at the completed site with eight bus chargers, the buses primarily use the chargers during the dwelling period between morning and afternoon runs; however, the chargers' usefulness is limited because the buses cannot fully recharge during that period. It is also unclear how useful these L2 chargers will be at the end of the eight-year term because a higher-power fast charger installed at the site through a different program seems to be better serving the fleet's needs.
- **Limited Interest in Public Charging from K–12 Schools.** In previous evaluation years, despite ensuring that all eligible Schools Pilot customers were aware of the pilot, Liberty staff observed limited interest in the Schools Pilot due to safety and liability concerns and a lack of demand for chargers from drivers. When the Schools Pilot was initially designed, Liberty expected that the incentive offerings for chargers would drive the procurement of EVs. However, in 2025, Liberty staff noted that the K–12 schools that had participated in the pilot installed bus chargers, and their participation followed rather than led to procurement of the buses, indicating that the incentives had not motivated these schools to electrify their fleet.

Despite the challenges of implementing the Schools Pilot, Liberty staff continued to plan for the construction of two additional sites in 2025. Staff remained optimistic about the future of transportation electrification within schools and highlighted the positive impact of installed chargers at the first completed site:

- **Planned Sites.** Liberty staff expressed optimism about the Schools Pilot sites, which are secured and still interested in participating in the pilot. Staff expect construction to begin in 2026. To the extent possible, Liberty's procurement team continued to work through the permitting process in 2025 to secure a contractor for the sites.
- **Ongoing Satisfaction at Completed Site.** In 2025, despite a lack of clarity about the long-term utility of the L2 chargers, Liberty staff reported that the chargers installed at the first Schools Pilot site, which was completed in 2023, continue to meet the site's current needs.
- **Clarity of the Maintenance-Ownership Models.** The Schools Pilot has a maintenance-ownership model in which Liberty owns and operates public-facing chargers, and site hosts pay for the chargers that are limited to staff use. Liberty staff expressed that distinguishing between the different uses of the chargers supports the goals of the Schools Pilot while ensuring that Liberty will not own the chargers at the end of the eight-year term.

Parks Pilot

Liberty had initially intended to sign on to a collective Utility MPA with the DPR in 2021. However, in 2022, the Utilities separated their negotiations to ensure that all legal team requirements could be met. Liberty staff opted to wait until the other Utilities had signed their own agreements and planned to leverage the acceptable terms that the DPR established. In 2025, the DPR finalized and executed MPAs with the other Utilities. However, due to staffing constraints at both Liberty and the DPR, Liberty maintained limited communication with DPR staff in 2025.

As in EY2024, Liberty staff noted concerns with the number of sites secured and timing for the Parks Pilot in 2025:

- **Site Consolidation.** Because of budgetary and timeline concerns, Liberty is currently considering consolidating the proposed three sites into one site with more ports. While they will make a final decision after the MPA is signed, Liberty staff still see an opportunity to reduce costs with site consolidation and plan to continue discussions to prepare for this path forward. However, Liberty staff noted that additional district-level coordination might be needed to make a final decision on the number of sites.
- **Pilot Design and Timeline.** While Liberty staff are hopeful about signing the MPA in 2026, they expressed concerns about the overall progress that will be made in 2026 according to the deadline prescribed by the initial decision. In addition to needing time for discussions about the agreement with the DPR, Liberty staff anticipates potential difficulty for procurement and contracts with vendors in time to start construction in the dig season from May to October.

Although Liberty staff are prepared to experience challenges with site-level coordination after the MPA is signed, they remain optimistic about the Parks Pilot and working with the State Parks Department as a result of the successful signing of the other Utilities' participation agreements:

- **Learning from Other Agreements Completed.** In previous evaluation years, Liberty monitored other Utilities' progress of participation agreements, which were ultimately finalized in EY2024. As they restart negotiations with the DPR, Liberty staff plan to leverage other MPAs and the lessons learned from the other Utilities' coordination with state and district staff to make these conversations more efficient and cost-effective.

Highlights

- **Schools and Parks:** Liberty staff reported significant challenges with staffing and competing priorities, resulting in limited activity for both Pilots in EY2025.
- **Schools:** Liberty continues to plan for the construction of two Schools sites in 2026, with both sites in the procurement and permitting processes.
- **Schools:** In EY2025, Liberty staff observed limited interest in public charging from K–12 schools, noting that schools that participated in the Pilot did so because they had already purchased electric buses and needed chargers, contrary to how the incentive structure was designed.
- **Parks:** As noted in previous evaluation years, to mitigate the cross-jurisdiction coordination challenge, Liberty plans to leverage acceptable terms of the MPA that the DPR established with the other Utilities in 2024 and is hopeful for its own signed MPA in 2026.
- **Parks:** Liberty staff continued to voice concerns about the Parks Pilot's timeline and planned number of sites, particularly in relation to the site-level coordination that constructing these sites will entail.

7.1.3. Lessons Learned

Schools Pilot

Liberty continues to prepare for construction of two Schools Pilot sites, with procurement and permitting activities laying the groundwork for the next phase of implementation. As noted in prior years, Liberty's Schools Pilot is designed to serve a targeted market sector by expanding public charging access in the Lake Tahoe area. From the outset, however, the pilot has faced challenges unique to K–12 school sites that have slowed progress. Due to internal constraints and competing responsibilities, both Schools Pilot sites remained in the procurement stage at the end of 2025. Liberty staff also reported difficulties navigating the permitting requirements administered by the Division of State Architect.

Despite these obstacles, Liberty staff advanced several procurement activities in 2025. These efforts included developing a preliminary design to support contractor bids and initiating RFP and RFQ processes for construction and equipment.

The Schools Pilot sites are helping to displace petroleum and reduce GHG and local emissions. The Liberty Schools Pilots sites to date have displaced over 15,000 gallons of petroleum and reduced 85 MT of GHG emissions. These sites all positively contributed to lowering local emissions, with CO reduction showing the most prominent projected reductions of more than 381 kg over a 10-year period.

EY2025 was the first full year of operation for the Liberty Schools Pilot site, and slow progress is being made toward meeting program targets. The one operational site in the Liberty Schools Pilot in EY2025 was activated in EY2024. This site has eight single-port 16 kW L2 chargers with a total installed capacity of 130 kW. The eight L2 charging ports meets 14% of the Schools Pilot Target of 56 L2 ports. No DCFC ports have been installed to date, so no progress has been made in meeting the target of two DCFCs. No sites have been activated in the Liberty Parks Pilot to date, so no progress has been made in reaching the target of five dual-port EVSE at three sites.

Utilization of the Schools Pilot sites is rising slowly, with higher consumption and demand in EY2025 than EY2024. The Schools Pilot site could shift significant charging to lower cost time periods and reduce monthly utility billing. Consumption from the single Liberty Schools Pilot site totaled 115 MWh in 2025, bringing total consumption in the pilot to date to 185 MWh. Total installed capacity remained at 130 kW in 2025. Both consumption and demand have grown slowly over time, with drops during the summer months aligning with the school year. Peak demand reached 125 kW, or 96% of installed capacity, in October of 2025 and continued through the end of the year. This indicates that all vehicles in the customer VAP have likely been delivered to the site. The Liberty Schools site consumed 45 MWh of energy (40% of total consumption) during the highest-cost time period of 4 p.m. to 9 p.m., and 56% of all charging sessions showed enough flexibility to be entirely shifted to lower-cost periods. The Evaluation Team estimates that if optimized through use of load management, the site could save up to $20,400 annually.

Parks Pilot

Liberty is well positioned to begin Parks Pilot negotiations with the DPR, drawing on the other Utilities' MPAs to inform its approach; however, deadline challenges persist. As noted in prior years, the original 2021 plan for the Parks Pilots was for all Utilities to enter into a collective participation agreement with the DPR. During the joint negotiations, Liberty followed the lead of the other Utilities. When the Utilities shifted in 2022 to pursuing separate agreements with the DPR, Liberty paused negotiations and instead began building its relationship with the DPR state office. Because most Utility MPA terms were negotiated in 2024 or earlier, Liberty used 2025 to reflect on lessons learned from the other Utilities' coordination with state and district staff as it prepared to restart negotiations. Liberty is aiming to execute an MPA with State DPR staff in 2026. However, staff also expressed concern about the pace of progress given the deadline established in the initial Decision. To stay on track, Liberty is working to be as prepared as possible before the construction window so that the remaining sites can be built in 2026.

Appendix A. Deep Dives

Barriers to Load Management

Heavy Freight Operator – SCE and PG&E

Heavy Freight Operator – SCE

Heavy Freight Operator – SCE

Medium-Duty Delivery Operator – SDG&E and PG&E

Barriers to Load Management

Introduction

Since EY2021 the Evaluation Team has consistently identified that most fleet operators (80%) in Utility MDHD programs are not practicing load management. In all evaluation year reports prior to EY2025, the Team provided assessments of the causes for this behavior in the *Statewide* chapter and the *Site Visit* section of each Utility report. In EY2023 and EY2024 the Team provided a detailed analysis of the potential annual cost savings and emissions reductions that program participants could achieve through adoption of load management practices. This analysis used charging session data to estimate how much electricity consumption could be shifted from the highest-cost time period to lower-cost time periods based on available power and time, and by how much sites could reduce maximum demand if they were subject to tariffs that included demand charges.

To gain greater insight into factors that have prevented fleets from implementing load management, the Evaluation Team undertook deep dive interviews with fleet operators in EY2025. To select appropriate fleets, the Evaluation Team modeled potential cost savings and emissions reduction for 160 sites with sufficient data (AMI and NSP) out of 250 operational sites in EY2024. Of the 160 analyzed sites, 100 showed achievable cost savings ranging from 25% to 45%. These 100 sites served as the pool of potential interviewees for barriers to load management deep dives in EY2025. Of these 100 fleets, 42 participated in semi-structured interviews.

This pool of 42 fleets represents nearly 60 EV charging installations, accounting for 57 MW of installed charging capacity and 31 MW of demand. As a point of reference, the best performing load-managed sites across Utility MDHD programs can limit electricity consumption during highest-cost period (4 p.m. to 9 p.m.) to 5% to 15% of total consumption. The 42 interviewed fleets often approach 50% of total consumption during peak periods.

All participating fleet managers consented to providing feedback about their fleet operations and experience with vehicle charging and load management and expressed a desire to understand how to improve fleet operations to reduce costs. Each fleet manager the Team interviewed reported that the interviews improved their understanding of electricity prices and gave them strategies to improve charging performance. Some fleet managers noted that they had already been working with the Transportation Electrification Advisory Services (TEAS) team at their respective Utility prior to engaging with the Evaluation Team.

Deep dive interviews were designed to assess several main characteristics of the selected fleets:

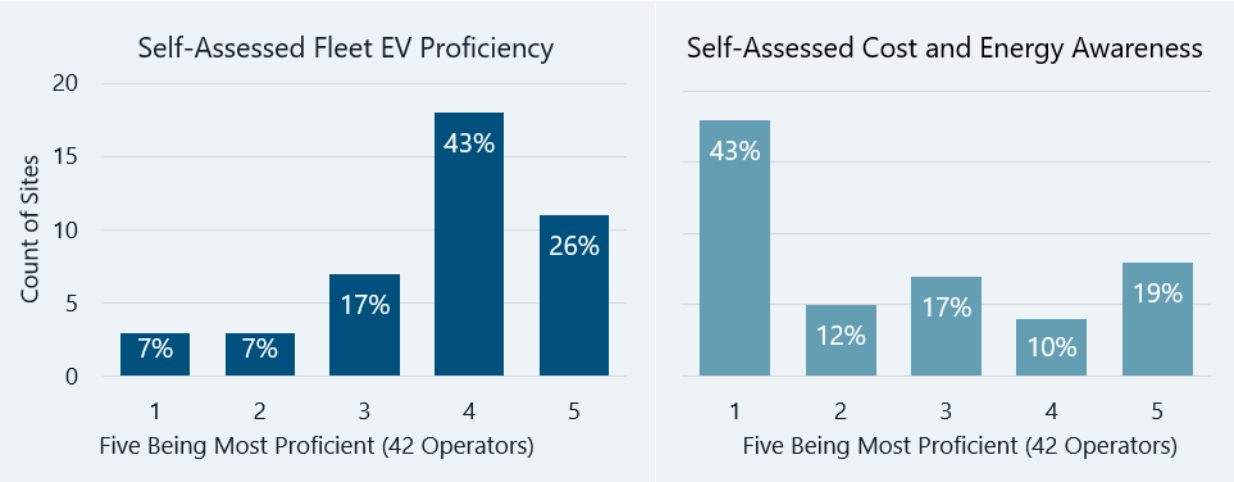
- Awareness of energy consumption trends
- Awareness of utility billing costs
- Barriers to use of load management, also known as charging management, with NSPs
- Solutions to fill existing gaps in operational knowledge or ability

Findings

To establish a baseline of understanding between participants and the Evaluation Team, the interviews began with fleet operators providing a self-assessment of their EV fleet operational proficiency on a scale of 0 (least proficiency) to 5 (most proficiency), considering variables like equipment and vehicle reliability, consistency of operations, and user experience. The same scale was used for an initial assessment of their awareness of energy usage trends and utility bills.

Figure 1 shows that nearly 14% of the interviewed fleet staff (n=42) reported low proficiency in EV operations compared with 26% reporting their fleet as highly proficient. The remaining 60% of fleet managers reported their proficiency as relatively good with room for improvement.

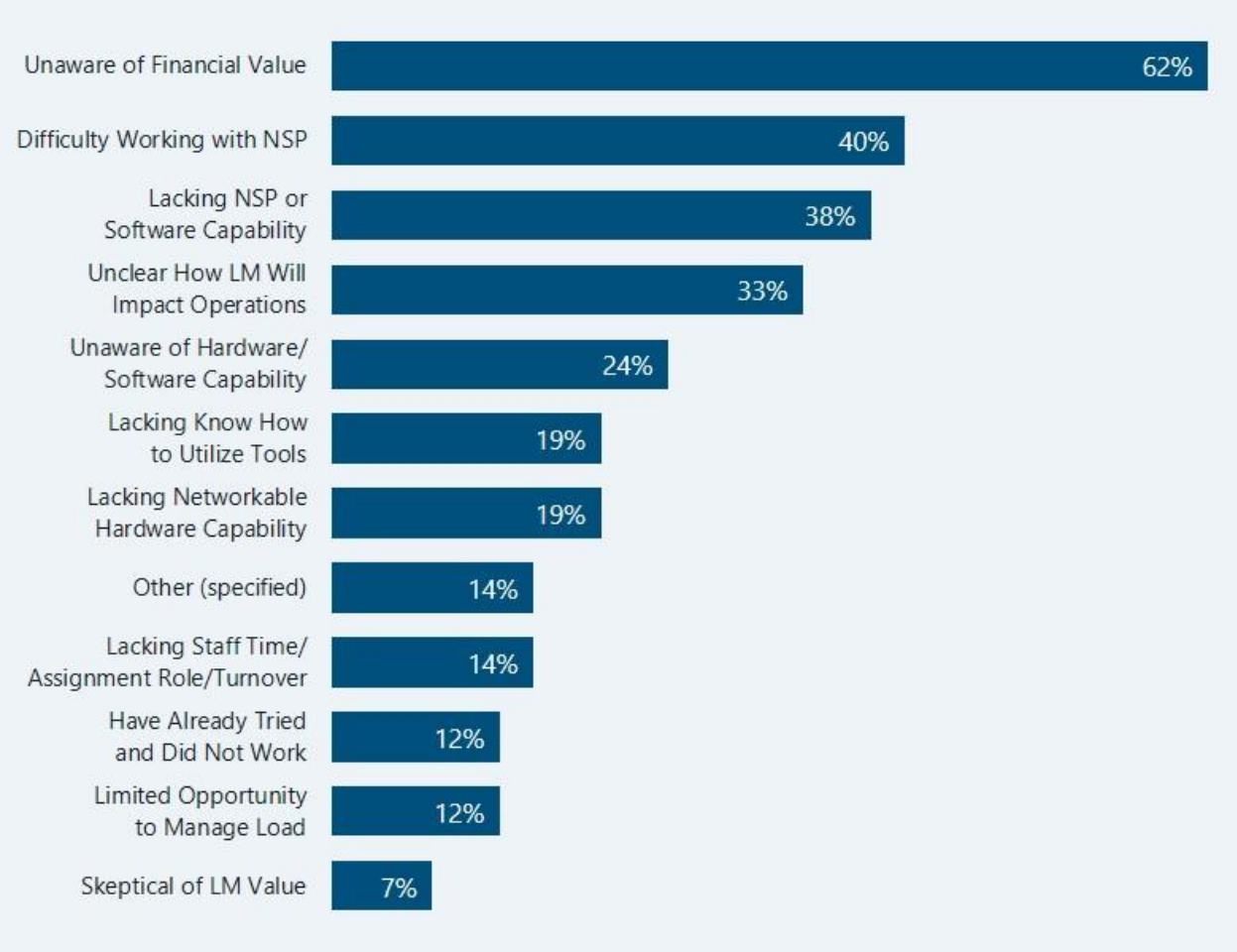
Figure 1. Fleet Self-Assessed EV Proficiency and Awareness of Cost and Energy



Interviews then shifted to knowledge and awareness of utility billing. Over 40% of fleet managers (15) stated they had little to no awareness of their utility billing (relevant to operational costs) or their site's general energy trends. Only 19% of fleets (8) reported high awareness. When digging deeper into the load management behavior of these eight fleets, the Team found that four had recently initiated load management, two had an interest in initiating load management, and one was actively working to initiate load management at the time of the interview. These self-assessments indicate that many fleets are approaching consistent operations but fleet managers lack awareness of their fleet's actual energy use and the variables that contribute to high or low energy costs.

The next set of questions were designed to identify barriers that may be keeping fleets from reliably using load management and determine potential solutions to enable adoption (see Figure 2). Fleet managers were presented with a list of potential barriers and solutions, then asked to identify all that applied to their operations.

Figure 2. Barriers to Load Management Cited by Fleets



The two barriers fleet managers most frequently identified were lack of financial awareness and difficulty communicating with NSPs. Many fleet managers did not have access to billing data, were not aware of their historical electricity costs, and did not know how those costs compared to examples of best-in-class fleet operations on similar utility tariffs.[1] Common issues with NSPs fleet managers mentioned included unresponsiveness to maintenance duties and lack of load management software that would enable sites to avoid high-cost energy consumption. Some fleet managers said that having signed long-term contracts with their NSP they feel they have little recourse to select a better-performing vendor. Notably, onboard charge management (time and power; charging speed) is largely unavailable in the commercial vehicle market despite having been common in the LDV market since 2011.

The Evaluation Team collects data from over 30 NSPs that serve customers across Utility programs. Of these 30 NSPs, 18 have customers that demonstrate a strong use of load management. However, as shown in Table 1, of the 30 NSPs servicing Utility MDHD programs, only two demonstrate high uptake of

[1] As a reference, the best in-class billed costs for each Utility is approximately $0.20/kWh under BEV-oriented tariffs among the three Utilities.

load management by the fleets they serve (FlipTurn and BP Pulse). These NSPs each serve more than ten customers across Utility programs. Both NSPs have also been reported as providing strong customer service regarding load management in deep dive interviews. This has resulted in high load management subscription rates (82% and 64%) across their customer sites. Four additional NSPs with load management capability also serve more than ten sites in this portfolio, however their subscription rates are below 25%. There are ten NSPs that serve between two and nine sites and have subscription rates that range from 10% to 40%. The two remaining NSPs each have a single site, both of which are implementing load management.

Table 1. NSPs with Fleet Sites Showing Load Management (Software or Manual Implementation)

NSPs with Load Management		Sites Showing Strong Load Management	Total Operational Sites	Strong Load Management Proportion
1	FlipTurn	9	11	82%
2	BP Pulse	7	11	64%
3	Redacted	7	46	15%
4	Redacted	6	28	21%
5	Redacted	4	9	38%
6	Redacted	2	16	13%
7	Redacted	2	21	10%
8	Redacted	2	5	33%
9	Redacted	2	9	22%
10	Redacted	2	4	50%
11	Redacted	1	5	20%
12	Redacted	1	6	17%
13	Redacted	1	6	17%
14	Redacted	1	8	13%
15	Redacted	1	8	13%
16	Redacted	1	2	50%
17	Redacted	1	1	100%
18	Redacted	1	1	100%

There are 18 NSPs that serve the deep dive interview participants. The Team used AMI and NSP data and deep dive interviews to determine the following information about these 18 NSPs:

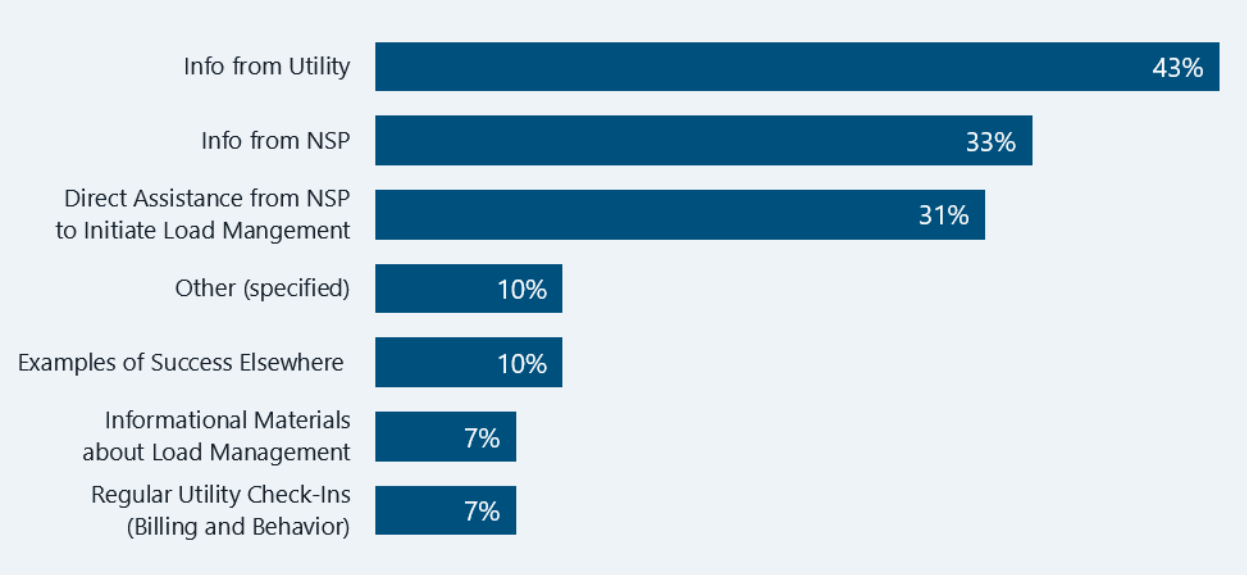
- Two were cited as having an excellent history of providing load management to fleet customers (as highlighted in Table 1).
- Five appear to show load management capability, but customers expressed challenges with getting support to implement this feature.
- The remaining 11 (over 60%) have not shown any evidence of load management capability, including from direct contact between the Evaluation Team and NSPs to verify information from fleet manager interviews.

When discussing strategies to overcome barriers to load management (Figure 3), the solution fleet managers most commonly reported was that fleets need and want more information and more feedback, because historically little has been provided. This could come from utility experts or vendors involved in

project operations. Improving fleet awareness of load management is likely to encourage adoption. Regular sharing of information would also mitigate process and information loss due to staffing turnovers for both fleets and vendors.

Another commonly discussed solution was for NSPs to provide more direct education and outreach or even hands-on support to fleets to initiate load management. Finally, several fleets requested case studies highlighting examples of fleets that had successfully implemented load management. This would help fleet operators to build feasible use cases, which they could share with their organizations to promote load management adoption. This topic was also identified in the Deep Dive sections of Utility MDHD program reviews in evaluation reports from EY2022 to EY2024.

Figure 3. Areas of Support Cited by Fleets



Through 42 fleet operator interviews, the Evaluation Team discussed several additional topics, resulting in the following findings:

- Eleven fleet operators (26%) have recently switched NSPs to reduce utility bills and better manage their fleet charging. Some fleets pivoted to different NSPs and hardware for subsequent infrastructure phases to improve control over fleet charging.
- Ten fleet operators (25%) are now using load management but were not during EY2024. Many other fleets reported making efforts to adopt load management.
- Twenty-two fleet operators (52%) are aware of load management concepts and its impact on operational costs for the fleet.
- Most fleets reported that issues with vehicle reliability and charger reliability had been corrected in the first two years of project operations. However, manufacturer bankruptcies have created lasting issues for some fleets, including leaving vehicles grounded indefinitely.
- At least five fleets that initially attempted load management ceased efforts because software and hardware challenges adversely affected their operations.

The paramount concern fleet operators communicated was reliability of vehicles and equipment to perform daily operations. Fleets will cease using load management best practices and infrastructure that enables load management if vehicles are insufficiently reliable for regular fleet operational needs. Multiple sites attributed reliability issues to communications between charging equipment and vehicles, hardware issues (cords, electronics modules, etc.), or both among other challenges.

Fleet managers noted that some vehicles go to sleep (shut off) when they do not begin charging within a certain amount of time after plugging in. As a result, vehicles would not begin charging at 9 p.m. when charging was set to initiate. One solution some fleets employ is to provide vehicles with a minimum trickle charging current to keep them awake instead of throttling to no power from 4 p.m. to 9 p.m. In these instances, demand ranged from approximately 1 kW to 5 kW, depending on the vehicle and EVSE. Some operators have also developed checklists for staff to support charging vehicles.

A large portion of school bus fleet operators within these interviews and previous site visits have expressed willingness to share information and reciprocate charger use with other school districts when visiting each other's locations. This may allow school districts to use EVs for extracurricular routes outside of their students' regular commutes to other school districts (such as field trips and sporting events) or venues that would otherwise be out of vehicle range. However, these fleets often need additional support to build a like-minded and prepared network.

Final Takeaways

Fleets participating in barriers to load management deep dive interviews had between one and six years of experience integrating EVs into their regular operations. Many have diligently worked through growing pains to improve vehicle utilization, whether challenges to reliability were presented by EVSE, vehicles, or NSPs. Despite these efforts, many have not been able to improve load management with current equipment or NSP vendors and some have either switched or are considering switching to another NSP or a different EVSE vendor. To improve vendor performance, the Evaluation Team recommends that fleets leverage performance-based contracts that allow more flexibility to switch providers in the event of underperformance.

To close each interview, the Team gave participants an overview of their fleet energy, billing and charging data and a comparison of their fleet's performance with that of best- and worst-performing fleets across all Utility programs. Each interviewee shared that this data-driven discussion improved their operational awareness and, for those not currently practicing load management, increased their motivation to initiate load management soon. The Evaluation Team estimates that the interviewed fleets could save an average of 35% on lifetime utility bills through load management, which is associated with similar emissions improvement as discussed at the end of each Utility *Grid Impacts* section.

To help fleets avoid on-peak consumption through load management, the Evaluation Team makes the following suggestions:

- NSPs participating in publicly funded programs should be required to both offer load management capabilities such as rules-based charging and conduct proactive outreach to fleets to increase awareness of load management practices and methods to avoid on-peak consumption.
- To be on the approved product list, all EVSE should be capable of load management and designed to avoid commercial obsolescence due to lack of network capabilities.
- Fleets need to review their energy trends and utility billing costs at least twice a year to develop familiarity and therefore appetite for engaging Load Management. Third Party providers and Utilities are in key positions to provide this information and ensure fleets understand the status and potential savings. Reviewing how long vehicles are connected but not drawing power may inspire fleets to change charging behavior. As highlighted in the *Charging Flexibility Analysis* of the *Statewide* chapter and each Utility *Grid Impacts* section, most vehicles are connected to chargers for much longer than they are consuming energy, which presents opportunities to shift consumption to lower-cost (and lower-emissions) periods.
- Success implementing TOU-based load management further allows fleets to take advantage of increased morning/afternoon charging. This is especially true for schools, which can potentially charge less at night, and for businesses operating Monday to Friday that can shift Friday night consumption to weekends.

Case Study: Freight Operator (SCE and PG&E)

Fleet Focus Points: Experimentation, Cost Parity, and Operational Flexibility

Vehicle Deployment and Operational Data

This site is a large heavy-freight hauler currently operating three sites within SCE territory and one site in PG&E territory in Southern California. In addition to their internal fleet of Class 8 vehicles—comprising models from Nikola, Tesla, BYD, Volvo, and, formerly, Freightliner—the operator offers charging to other heavy drayage fleets in the area. The vehicles' daily duty cycles vary by site and conditions, but the fleet cumulatively operates around 100,000 miles per week, largely as drayage vehicles, with around 75 vehicles in its Southern California fleet in late 2025. The fleet ultimately plans to operate 123 EVs across four SRP sites throughout California.

Fast Facts

Site Type	Multi-site freight operator
Electric Vehicles	Nikola Tre, BYD ETH8, Volvo VNR Electric, and Tesla Semis
Charging Stations	48 of 360 kW dual-port PhiHong DCFC (96 ports)
ICE Fuel Type	N/A, new fleet



Fleet vehicles are shared between the four operational Charge Ready sites, including Nikola Tre, BYD ETH8, and Volvo VNR Electric EVs, as well as an undisclosed number of recently acquired Tesla Semis. The fleet operator manages additional sites throughout the United States, and while their operations in California have maintained course, they have experienced business slowdowns at sites in the central and eastern United States, directly correlating with the loss of federal funding. However, along the West Coast, the fleet manager has seen increased customer demand and continues to expand its electric truck operations. The table below summarizes each of the four sites' vehicles, charging stations, installed capacity, and any unique characteristics.



Site	Chargers	Vehicles	Unique Site Characteristics	Installed Site Capacity
SCE 1	13x 360 kW PhiHong	14x Nikola 10x BYD 5x Volvo Tesla Semi	Drayage operation	5 MW
SCE 2	12x 360 kW PhiHong		Second phase built due to significant demand and extremely high usage	4.3 MW
SCE 3	6x 360 kW PhiHong		Low utilization (~400 kW)	2.2 MW
PG&E	16x 360 kW PhiHong	5x Nikola	Onsite grid buffering	5.7 MW

Across the four sites, the fleet manager has gained significant insight into the reliability and capabilities of each manufacturer's offerings. Freightliner, while initially trialed as part of the fleet, was ultimately deemed unsuitable for the fleet's operations due to low charging speeds, despite the truck's ability to leverage two separate charging ports simultaneously. Nikola and Tesla vehicles have shown good reliability so far; however, Tesla's vehicles have been in operation for only a short time, and their long-term durability is not fully tested. BYD and Volvo fall in the middle of the pack, offering adequate maintenance support but still face some weaknesses, namely, BYD's limited dealer network and Volvo's reliance on a third-party maintainer.

Chargers and Charging Usage Patterns

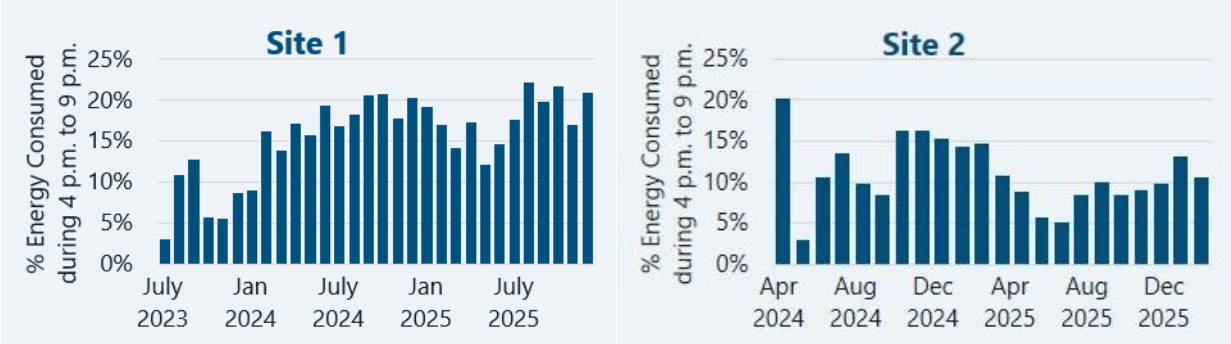
The fleet uses AmpControl software installed on 360 kW PhiHong DCFC chargers at each site to limit and allocate charging power based on the number of vehicles actively charging. The software does not effectively manage load, so most sites experience significant charging usage during the 4 p.m. to 9 p.m. peak period. This is largely because the sites serve as semi-public or "opportunity" charging hubs.



However, the significant site charging throughput at other hours of the day means that even with the unrestricted charging, the sites generally use less than 20% of their energy during the 4 p.m. to 9 p.m. peak period, as shown in the figures below.



While the fleet manager does not specifically manage charging, they achieve among the lowest average cost-per-kWh in the program, where three of the operator's four sites are averaging $0.25/kWh. This is due to the exceptionally high energy throughput at the site.



Two of the fleet's three SCE sites and the PG&E site are experiencing low demand, meaning that their charging demand is significantly less than the site's built-in electrical capacity. This is because their vehicles only accept 100 kW to 150 kW of power, versus the charging stations' maximum output of 360 kW. SCE Site 2, however, frequently exhibits an extremely high load factor, peaking at 43%.[1] To reduce the impact of frequent, heavy use, the site currently uses a nearby unaffiliated commercial charging installation to handle overflow. With expected increased usage, the fleet manager plans to expand this site with a second phase of 25 to 30 chargers. Staff at SCE Site 1 are examining how to reduce their demand during the peak period to spread power consumption over a wider period and help lower costs. The fleet's PG&E site operates some of its chargers on an off-grid solar battery installation, and the remainder on a solely grid-tied installation; their battery chargers are prioritized during daylight hours. This allows them to "coast" on stored power through the highest-cost 4 p.m. to 9 p.m. peak period and into the evening, when the grid-tied chargers are prioritized for usage.

The fleet manager is actively expanding in California and Oregon, with additional sites in the San Francisco Bay area and Sacramento. With these additional sites, the fleet will establish a corridor between Los Angeles and San Francisco Bay and expects utilization patterns to change as routes expand and Southern California vehicles begin to move outside of their current region.

Final Takeaways

The fleet manager is aggressively expanding its operations on the West Coast and is pursuing thoughtful deployments that consider the environmental context for charging stations. The fleet manager leverages as much solar generation and battery storage as is economically and logistically possible in PG&E's territory. The fleet manager ensures that its sites are largely open for use by other operators and that the "ecosystem" of each site (power, availability, and usage) is matched to the requirements of both the regional fleet and the other operators they serve. Their sites generally see high usage, and the fleet has contributed substantially to the number of heavy-duty electric vehicle miles traveled in California. Upcoming expansions are expected to significantly increase the number of EVs and the associated miles.

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[1] Load factor is calculated as: $\left(\frac{Total\ energy\ usage}{Maximum\ 15\text{-}minute\ demand * 96\ 15\text{-}minute\ periods * 30\frac{days}{mo}}\right)$

Case Study: Freight Operator (SCE)

Fleet Focus Points: Experimentation, Cost Parity, Operational Flexibility

Vehicle Deployment and Operational Data

This fleet is a large heavy-freight hauler currently operating a site within SCE territory in Southern California. The operator's electric fleet currently consists of 14 Class 8 trucks and five yard tractors. Of the Class 8 trucks, the operator has 10 Freightliner eCascadias and four Kenworth T680Es; yard tractors are all from Autocar. The site was an early adopter of electric heavy-duty vehicles and has used a variety of vehicles and chargers with varying levels of production readiness.

Fast Facts

Site Type	Freight Operator
Electric Vehicles	10 Freightliner eCascadias, Four Kenworth T680E Class 8 trucks, Five Autocar EACTT yard tractors
Non-Electric Vehicles	700+ diesel trucks across multiple sites (sleeper cab configuration)
Charging Stations	18 dual-port ABB Terra 184 (180 kW), Two single-port ABB Terra HP 175 (up to 350 kW when paired)
ICE Fuel Type	Diesel

The site's Class 8 trucks operate on local routes throughout Southern California, primarily within the Los Angeles basin but with some routes to nearby regions. The vehicles operate on a single shift, generally departing the depot between 5 a.m. and 8 a.m. and returning between 6 p.m. and 7 p.m. This schedule limits the vehicles' ability to charge during the day. The fleet manager expressed an interest in additional vehicles with longer ranges and faster charging capabilities to support its longer-haul operations and to minimize EV downtime. The fleet manager expected PACCAR to manufacture these longer-range vehicles thanks to fiscal support by the DOE Supertruck 3 project, but the project is currently on a funding hold.



The fleet manager noted that they had explored multiple Class 8 truck makes and models of various levels of production readiness as potential options for the full fleet deployment. Multiple trucks the fleet procured from one manufacturer had major issues early on, and three years later the fleet is still working to remove that reputation with drivers who are hesitant to use the trucks. The fleet's five electric yard tractors generally have low utilization, and charge infrequently as a result.

Chargers and Charging Usage Patterns

The fleet charges its vehicles on 18 dual-port ABB Terra 184 180 kW charging stations and two single-port ABB Terra HP 175 175 kW chargers. The Terra HP 175 chargers are designed for flexibility and can pair together and dispense 350 kW if only one vehicle is connected. The Terra 184 units are deployed such that each charging space has a single Terra 184, with the second cable providing redundancy in the event of charging issues. Charger reliability is good overall, though the HP 175 units had issues during commissioning and did not charge reliably when pairing together.



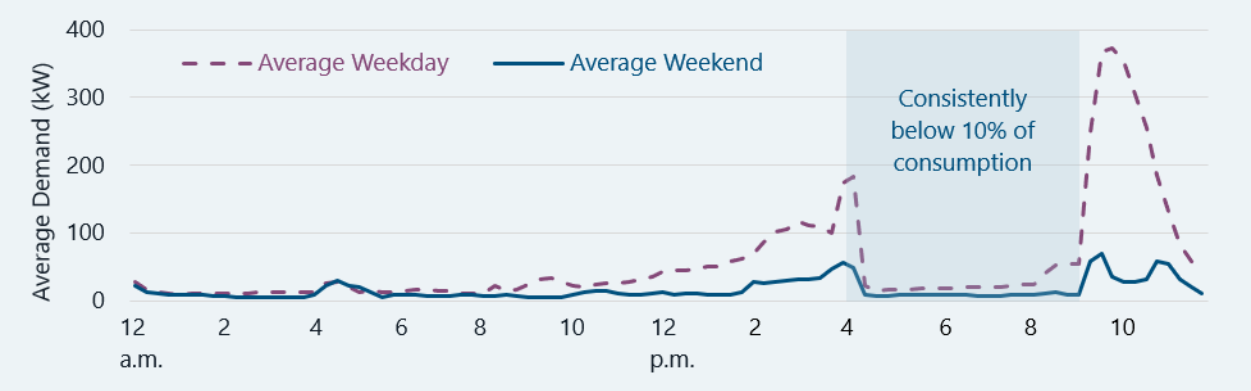
The charging stations operate on the Flipturn network. Chargers are split between two installations: the Charge Ready Transport site, which is connected to a traditional grid-tied system; and a non-program deployment tied to an off-grid solar photovoltaic (PV) battery energy storage system (BESS) installation. Each installation is metered separately. The site uses the two installations to assess how the EV costs per mile compare to the cost of diesel vehicles under the two distinct charging paradigms these installations provide.

Drawing power from the 450 kW solar PV array, the 1 MWh BESS is heavily used to minimize consumption during the highest-cost periods of the day and throughout the day in sunny weather. The conventional grid-tied chargers are used for overnight charging. Opportunity exists to increase storage and solar utilization, with an estimated four to five hours of generation being curtailed during the summer. The site plans to work with SCE to implement net metering to avoid curtailing its excess generation, but the fleet manager expressed that this is a relatively low priority. Overall, the fleet uses the PV-BESS installation for approximately 65% of the energy delivered to vehicles with the remaining 35% coming from the grid-tied charger installation.



The site limits charging to 5 kW during the peak-rate period, and returns to providing full power after the period ends. This low level of charging prevents vehicles' onboard charging systems from entering sleep mode, allowing them to automatically resume full-power charging upon the lifting of the power restriction. This charging strategy results in extremely low energy usage during the peak period, averaging around 10% of total monthly energy consumed since the project's activation and lowering overall costs to around $0.25/kWh, which is among the lowest billed costs among SCE customers.

Average Weekday and Weekend Demand



The fleet manager estimated that the solar PV array produces around 1.8 MWh of energy daily. The BESS is sized to serve eight to nine trucks per day during the summer and four to five trucks during the winter due to the seasonal reduction in solar insolation and the resulting slower charge rate to the BESS. The fleet manager expressed interest in potentially shifting charging from Friday night into daylight hours on Saturday, which would allow the fleet to avoid draining the battery and to take better advantage of the solar energy production.

The fleet manager noted that the Charge Ready Transport program provided useful financial support. However, the addition of the PV-BESS system added complexity and required coordination for site construction, and ultimately delayed progress on site installation. Lack of supporting infrastructure affected the timing of the first truck delivery. In addition, the supply voltage for the project was limited to 480V; the site had hoped for higher voltage to allow for expansion but based on the expected load of the chargers on the transformer the program limited the supply voltage. Originally, the site had planned for 30 chargers but decided to scale back the site to 20 chargers after the finalization of the 480V service.



Final Takeaways

While the Charge Ready Transport program site represents a traditional grid-tied setup, the fleet's on-site PV generation and BESS represent a significant source of energy for fleet operations. This approach allows the fleet to compare the costs of operation for each approach to that of diesel, and assess how effectively each avoids expensive peak-rate energy consumption. The Class 8 trucks operate adequately and are able to fulfill their duty cycles, but the fleet is eager for next-generation vehicles to arrive with additional range and faster charging speed to allow for less downtime, particularly with its yard tractors.

Case Study: Freight Operator (SCE)

Fleet Focus Points: Operational Continuity, On-site Generation, Vehicle Reliability

Vehicle Deployment and Operational Data

This fleet is a large heavy-freight hauler currently operating one site within SCE territory in Southern California. The operator's Charge Ready Transport electric fleet consists of 40 Class 8 trucks manufactured by Freightliner and formerly included six trailers with electric transport refrigeration units (TRUs). The TRU manufacturer that ceased operating within the TRU sector and the vehicles were pulled from the fleet. This site was the fleet's only current participant in the Charge Ready Transport program when the fleet manager interview took place in early 2026; the fleet operates 130 EVs across North America, all of which are manufactured by Freightliner.

Fast Facts

Site Type	Freight Operator
Electric Vehicles	40 Freightliner eCascadias trucks, Six unspecified eTRUs (defunct)
Non-Electric Vehicles	61 diesel trucks
Charging Stations	40 dual-port ABB Terra 184 (180 kW)
ICE Fuel Type	Diesel



The site's Class 8 trucks are equipped with either single- or dual-axle drivelines. Vehicles operate Monday through Saturday on local routes throughout southern California, averaging between 80 and 90 miles per route, with dispatchers aiming for round trips of between 100 and 150 miles. The vehicles operate on a single 12-hour shift, generally departing the depot between 4 a.m. and 5 a.m., and returning between 4 p.m. and 5 p.m. When operations began in early August of 2024, vehicle reliability was suboptimal, with the fleet manager estimating that at any given time, 25% of the EVs at the site were not operating. However, at the time of the interview in January 2026, vehicle reliability had significantly improved, with the fleet manager noting that it was rare to have more than two vehicles down on any day. The fleet manager credits their local Freightliner dealer for this improvement, reporting that the dealer dedicated significant time and staff resources to identifying and solving problems, which involved spending weeks on site troubleshooting.

The fleet manager said that drivers enjoy and have had positive experiences with the EVs but did not disclose details about their experiences in the interview.

The fleet planned to charge the six TRU units that the fleet no longer owns using six ESL-manufactured charging stations on a central island; however, the TRUs required 240 V power and the ESL chargers are 480 V. Because of this mismatch, the TRUs were originally charged on the other infrastructure, so the island's TRU chargers have not received significant usage.

Chargers and Charging Usage Patterns

The site charges its vehicles on 40 ABB Terra 184 180 kW charging stations with two ports. The chargers are deployed such that each charging space has a single Terra 184, with the second cable providing redundancy in the event of charging issues. According to the fleet manager, charger reliability has been fair; the chargers frequently require tending, charging sessions commonly terminate prematurely, and vehicles frequently require several attempts to successfully initiate a charging session. Staff walk the aisle frequently to ensure that trucks continue to charge as expected.



The charging stations operate on the BP Pulse network and are tied to a solar-battery storage installation. Two on-site 2.1 MWh batteries store and dispatch power generated by a 1.5 MW solar array. The fleet manager estimates that the solar photovoltaic (PV) system generates 2.25 million kWh per year; Utility data show that the site consumed 2.24 million kWh over the course of 2025, meaning that this site's entire annual usage could be offset by its solar PV generation. The site also sells electricity back to the grid, allowing the company to generate revenue during midday when few vehicles are charging.



The site implemented BP Pulse's automated load management capabilities to limit the amount of charging starting at 4 p.m. and ending at 8 p.m. During 2025, the site consistently showed that the

proportion of energy consumed during the peak-rate period of 4 p.m. to 9 p.m. was less than 10%, despite dispensing between 140 MWh and 200 MWh monthly. This is an excellent avoidance of the 4 p.m. to 9 p.m. period, made possible by the use of on-site storage for charging during this time. However, the need for operational continuity drives fast charging speeds all coming online at the end of the scheduled throttling period, which results in a massive and rapid increase in grid load. On average in 2025, demand ramped from 140 kW at 8 p.m. to 1,320 kW at 10 p.m., with two major spikes (140 kW to 550 kW in 15 minutes, and 611 kW to 1,120 kW in 15 minutes) making up most of the rapid increase in consumption. The scale and rate of these increases in grid load raise concerns about the ability of the grid to support load management induced peaks however, the pending implementation of SCE demand charges may provide price signals that help smooth out energy consumption. Reviews of the site's vehicles, routes, and charging stations indicate that the site may be able to slow charging by 25% without impacting vehicle operations, allowing for a more gradual ramp and putting less strain on the grid.

Final Takeaways

Overall, the fleet prioritizes seamless operation and does not monitor differences in costs per mile between its diesel and electric models. Despite a difficult start, the EVs now operate reliably, thanks to the efforts of the fleet's Freightliner dealer and technicians. The site's PV array generates enough energy to cover the annual energy consumption of the on-site EVs, allowing the site to store significant amounts of energy to provide a smooth transition into evening charging and avoid the expensive 4 p.m. to 9 p.m. period. The panels also generate revenue for the site, as SCE allows for the generation of Energy Export credits with the solar PV system. While the site's TRU units performed well, the intended charging stations' power was incompatible with the units themselves. Additionally, the TRU manufacturer withdrew from the TRU sector, taking its units out of service and forcing the fleet to explore alternative options for electrifying its TRUs.

Case Study: Delivery Operator (SDG&E and PG&E)

Fleet Focus Points: Multi-Site, Multi-Utility, and Significant Vehicle Deployment

Vehicle Deployment and Operational Data

This medium-duty vehicle logistics fleet participated in Utility MDHD Fleet programs with five sites within PG&E territory and one site in SDG&E territory. All of the fleet's EVs at these six sites are BrightDrop ZEVO 600 cargo vans. While the fleet currently operates around 50 electrified sites throughout California, these six are the only current participants in the EV Fleet and Power Your Drive for Fleets programs. The fleet plans to continue building out infrastructure at more sites, upgrade existing sites with more network capability, and standardize equipment, and implement a uniform network provider across all of its sites.

Fast Facts

Site Type	Multi-site delivery vehicle operator
Electric Vehicles	BrightDrop ZEVO 600 cargo vans
Charging Stations	50 of 25 kW dual-port BTC Power DCFC (100 ports) 58 of 16.5 kW single port L2
ICE Fuel Type	Diesel

As of December 31, 2025, the operator had 67 BrightDrop electric delivery vans across its sites in PG&E territory, generally operating between 45 and 100 miles per day, and 21 vehicles at the site in SDG&E territory, which averaged 100 miles a day and approached 150 miles on particularly heavy days. Sites were originally scheduled to receive vehicles from a different manufacturer; however, that company ceased operation in 2021, forcing the fleet to change its sourcing plans. At many of the sites, the fleet uses DCFCs procured from and installed by BTC Power. The stations were manufactured in 2020, but the sites took until early 2024 to be fully built out and energized. The table below summarizes site characteristics.



Site	Chargers	Vehicles	Unique Site Characteristics	% of Energy Consumed from 4 p.m. to 9 p.m.
PG&E 1	13x 25 kW DCFC dual port 8x 16.5 kW L2 single port	15x BrightDrop Zevo	100-mile routes	20% – 25%
PG&E 2	50x 16.5 kW L2 single port	29x BrightDrop Zevo	60-mile routes	30 – 35%
PG&E 3	11x 25 kW DCFC dual port	8x BrightDrop Zevo	Routes not specified	30 – 40%
PG&E 4	10x 25 kW DCFC dual port	6x BrightDrop Zevo	No usage since August 2025. Site decommissioned and vehicles redeployed	10 – 15%
PG&E 5	5x 25 kW DCFC dual port	9x BrightDrop Zevo	45 – 80-mile routes	40 – 50%
SDG&E	11x 25 kW DCFC dual port	21x BrightDrop Zevo	80 – 150-mile routes	30 – 35%

Differences between sites are primarily due to the number of vehicles, though two sites operate 16.5 kW L2 chargers, a departure from the operator's standard deployment of the 25 kW BTC Power DCFCs. The fleet manager noted that for their purposes, L2 charging was likely adequate, considering the vehicles' long dwell times and short routes, and that the DCFCs may be more powerful than needed. Switching from DCFC to L2 would likely extend the vehicles' charging time but might also reduce demand charges by reducing charger peak power by nearly half.

Chargers and Charging Usage Patterns



Across its five sites in PG&E territory, the fleet operates 39 30 kW BTC Power DCFCs (78 ports), and 58 16.5 kW Eaton branded L2 chargers (58 ports). One of the sites has seen little operation since August 2025, and was decommissioned, with its vehicles transferred to another site. In SDG&E territory, the fleet operates 11 of the same 25 kW DCFCs, for a total of 22 ports.

While the fleet manager did not share load management details in their interview, most of the PG&E sites demonstrated a significant dip in the amount of energy they consumed from 4 p.m. to 9 p.m. between May 2024 and December 2024. Each of the active sites at that time saw its usage during the peak-rate period dip by 10% to 15% over the course of one or two months, reaching a low around August 2024. In January 2025, usage during the peak period increased substantially, by between 20% to 30%, depending on the site, and remained at that rate through 2025. Dispensed energy continued to increase through both the reduction and subsequent increase in consumption between 4 p.m. and 9 p.m., indicating that load management may have initially

been used to reduce the proportion of energy during high-priced times. It is unclear why the sites elected to return to high-cost energy, but a frequently cited reason by many fleet managers is the prioritization of operational continuity over cost reduction. Some sites have added additional EVs and may have sought to ensure that all vehicles could fully charge each night.

The fleet manager highlighted the functionality and reliability of their DCFCs, which they attributed to the manufacturer's involvement and communication. Sometimes the dual-port chargers had trouble switching between ports, but firmware updates helped solve this problem. The fleet manager also highlighted reliability of the BrightDrop vans; however, GM has discontinued production of these vehicles, and the fleet was engaged in conversations with other manufacturers to source electric vans moving forward.

Final Takeaways

This fleet began its move toward electrification to comply with pending regulatory requirements and take advantage of incentives for EVs and charging infrastructure. Although the regulatory requirements have softened, the fleet still plans to apply experiences from these sites to inform how electrification can benefit the broader fleet from a financial and operational perspective. EV drivers and fleet managers have had positive experiences with the GM BrightDrop vans, and with that model now discontinued, they hope to find another affordable reliable delivery vehicle with similar range to cover their regular routes.

Appendix B. Methodology

This section describes the evaluation methodologies for the MDHD programs and Public Charging programs (AB 1082 [Schools Pilot], AB 1083 [Parks Pilot], and EV Fast Charge program), including data collection and analysis activities. The Evaluation Team collected primary or secondary data (data collection) and transformed that data to produce findings (analysis). Some methodologies are identical across programs, while others are specific to a subset of programs.

Table B-1 lists the evaluation activities conducted for each program for EY2025. The individual program chapters discuss the evaluation activities, methodology, and findings.

Table B-1. EY2025 Data Collection and Analyses by Program

Type of Data Collection and Analysis	Liberty	PG&E			SCE		SDG&E	
	Schools and Parks Pilots	MDHD	Schools and Parks Pilots	EV Fast Charge	MDHD	Schools and Parks Pilots	MDHD	Schools and Parks Pilots
Program Data and Materials	●	●	●	●	●	●	●	●
AMI/EVSP Data	●	●		●	●	●	●	●
Site Visits	●	●	●	●	●	●	●	●
Site Costs		●	●	●	●	●	●	●
Interviews	●	●	●	●	●	●	●	●
Surveys		●			●		●	
Delphi Panel		●			●		●	
EV Adoption			●	●		●		●
Grid Impacts		●	●	●	●	●	●	●
Counterfactual Development	●	●	●	●	●	●	●	●
Petroleum Displacement		●	●	●	●	●	●	●
GHG and Criteria Pollutant Emissions Reductions		●	●	●	●	●	●	●
Health Impacts		●	●	●	●	●	●	●
Site Visit Findings		●	●	●	●	●	●	●
Co-Benefits and Co-Costs		●			●		●	
Interviews and/or Survey Findings	●	●	●	●	●	●	●	●
Market Effects		●			●		●	

The Evaluation Team developed an evaluation methodology for data collection and analysis to address three research objectives:

- **Research Objective 1.** Determine whether transportation electrification investments accelerated widespread transportation electrification, reduced petroleum dependence, helped meet air quality

standards, reduced GHG emissions, and achieved the goals of the Charge Ahead California Initiative.[152]

- **Research Objective 2.** Determine whether transportation electrification investments maximized benefits (including co-benefits) and minimized costs (including co-costs) and the extent to which the costs and benefits accrued to DACs.
- **Research Objective 3.** Maximize lessons learned from analyzing data collected during program implementation.

The Evaluation team designed the scope of activities to address the specific characteristics of each program at an appropriate level of rigor and to produce findings with a meaningful level of detail. The evaluation activities selected for each program were largely influenced by the number of sites in the participant population for that program and within the market sector.

Site Terminology

This report uses the following terminology to describe participating sites or sites included in the evaluation effort:

- **Utility Construction Completed:** Sites for which the Utility has completed its scope (TTM, TTM and BTM, and turnkey installation)
- **Activated:** Sites with installed charging stations that are available for use
- **Operational:** Sites for which AMI and/or EVSP energy usage data have been received from the Utility or EVSP
- **Closed Out:** Sites for which the Utility has finalized financial documentation and paid the rebates for the installed chargers

The Evaluation Team reviewed program participation and adjusted the sampling methodology, scope, and timeline of activities to maximize efficiency. This report provides impact and process evaluation findings that the Team derived by using a census approach to gather site-level inputs from AMI and EVSP data, site visits, or surveys from activated sites. For activities that required a more granular approach to data collection and for which program or market sector participation levels were insufficient to allow reporting at any meaningful level of detail, the Evaluation Team updated the scope and timeline of activities to be performed and reported as part of the next evaluation cycle.

Medium-Duty Heavy-Duty Programs Evaluation Methodology

This section outlines the data collection and analysis methodologies for the MDHD programs.

Data Collection Methodology

To assess the MDHD programs, the Evaluation Team collected program performance metrics, program materials, AMI and EVSE data, and site visit data and conducted surveys and interviews.

[152] Environment California. December 17, 2021. "Charge Ahead California Budget Request 2022." environmentcalifornia.org/programs/cae/charge-ahead-california

Program Performance Metrics

Data on program performance metrics included information about program applications such as count of charging ports, number of EVs procured, site status (inside a DAC or outside a DAC), time in each program phase, and site costs, where available. These data support an understanding of program performance (such as the median number of days sites spent in different program phases and the percentage of applicants from different market sectors) and program spending.

The Evaluation Team collected and securely transferred data between the Utilities' secure SharePoint sites or other secure file transfer systems and our own Microsoft Azure cloud-based environments. We completed this transfer monthly for most data, with some variation in timing among PG&E, SCE, and SDG&E. Once we received data from each Utility, we moved these data to a secure data warehouse for storage and retrieval.

Program Materials

To understand how the programs operate and communicate with customers, the Evaluation Team reviewed available program-related materials, such as Decisions, Advice Letters, and Program Advisory Committee (PAC) presentations. We reviewed the changes in program design and implementation and the legal and regulatory environments that impact the programs, including site and vehicle requirements, and outreach and onboarding approaches. The program material review allows the Team to establish a foundational understanding of program design, track changes in design over time, and understand the implementation progress.

The Evaluation Team reviewed the following program performance metrics and materials to evaluate the MDHD program.

Program Materials Reviewed
• PAC presentations • Program data such as number and type of EVSE installed, and VAPs • Regulatory documents such as Decisions and Advice Letters • Utility websites: ▪ Programs and handbooks   ▪ Application and application preparation and information documents   ▪ Fact sheets and case studies   ▪ Funding information   ▪ OEM information • Marketing materials: ▪ Email and other collateral   ▪ Webinars

AMI/EVSP Data

The Evaluation Team used AMI data to estimate charger usage, a key input for subsequent analyses and estimations of program impacts such as impacts to the grid, petroleum displacement, emissions

reductions through EV adoption, and associated health impacts.[153] The Evaluation Team collected and securely transferred all AMI data between the Utilities and Microsoft Azure cloud-based environments, used Azure Databricks to transform and standardize the data, imported the standardized data into an SQL server data warehouse for secure storage and retrieval, and aggregated the data for subsequent calculations and analysis. We performed these transfers monthly, with some variation in timing among the Utilities. Time-stamped energy consumption data were recorded in 15-minute intervals.

EVSE data provided by participating EVSPs were another critical data source. The electric Utilities developed a process for screening and approving EVSPs based in part on their ability to provide essential monthly charging data of EVSE sessions, intervals, stations, and ports.

Together, AMI and EVSE data provided the basis for analyzing at a granular level program performance such as customers' ability to shift loads to off-peak times in response to time-varying rates. The Evaluation Team used data from EVSPs to examine port utilization, which is based on the amount of time a vehicle is parked at a charger and consuming energy.

The Evaluation Team worked to obtain complete AMI and EVSE data from the Utilities and EVSPs for every charging session. In a few cases when AMI data was missing, the Team worked with the Utility to obtain these data from sites that had not provided it to incorporate into future analyses. In some cases when AMI data were not available, either a customer provided a sub-metered dataset, or the Team synthesized data from existing EVSE data.

Synthesized Data

Across Utilities, a small number of sites did not have AMI data or hourly distributions for brief periods of time. Consequently, the Evaluation Team generated representative AMI data for these sites based on available EVSP data through a synthesis process using a conversion factor of the ratio between EVSP data and AMI data. We derived specific conversion factors for each site by evaluating the ratio of total kilowatt-hours delivered as reported by EVSPs, which in most cases existed for the same site at a different time period, or at the same time period as the missing data for similar EVSE and vehicles.

Annualized Data

The Team considered all operational sites for annualization.[154] In the EY2021 evaluation, we annualized all sites with greater than six months of usage data and considered annualizing sites with between three and six months of usage data depending on observed usage patterns. For EY2022 to EY2025, the Evaluation Team annualized all sites to provide a more complete picture of the entire program to date and to project the impacts of the program over a full 10-year life. In general, sites with a period of performance of less than six months will inherently have lower total utilization than fully developed sites. As a result,

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[153] Liberty Utilities does not use AMI, so the Team collected regular meter data instead.

[154] The Evaluation Team annualized electricity usage data for sites with operational AMI data (data indicating that EVs were actively being charged). We extrapolated partial year site electricity usage data out to a full year to make site-to-site and year-over-year comparisons.

annualizing sites that have been operational for six months or less will underrepresent the full 10-year impact; however, excluding those sites would create an even greater underrepresentation.

To produce the most accurate assessment of site performance, the Team annualized each site by creating a representative 12-month operation period that could be projected to the point when the site would reach its 10-year life. We calculated the 10-year life by determining when the operational use of the EVSE would begin and projecting forward 10 years from that date. For sites that had more than 12 months of operating data without a significant increase in use in the most recent 12 months, we used those 12 months as an annual profile. For sites with less than 12 months of fully developed usage data, we removed the months of data before the date the site reached 75% of its maximum monthly use and replaced that data with a synthesis of all months of data following 75% of the maximum utilization.

Site Visits

Site visits are an important part of the data collection process as they provide an on-the-ground view of the sites and access to stakeholders such as fleet and facility managers who may participate in surveys and in-depth interviews. Site visits can provide answers to questions related to the integration of infrastructure- and vehicle-focused programs. They also allow us to confirm which vehicles and charging hardware were delivered and are in operation and how routes, utilization, and duty-cycles impact performance and electricity demand.

During site visits, the Team collected qualitative and quantitative information that provided us with an understanding of fleet composition and operations. We compared these data against Utility-provided information for individual sites to gauge progress toward contractual goals. The Team collected the make, model, and number of EVs on site and information about types of conventional vehicles or equipment replaced, charging equipment, charge management capabilities, electrical infrastructure, future vehicle/equipment replacement plans (including future vehicle adoption), public funding sources, and interest in or use of on-site solar and/or storage at the site.

The Team held meetings with facility managers and other personnel to gain a detailed understanding about each site. At sites where the site host was able to answer our questions and the fleets had more than three months of operational experience, the Team asked about satisfaction with the Utility program, charging infrastructure, and EVs. We also asked about any co-benefits or co-costs the site host had experienced or anticipated. We also inquired about the availability of telematics or fleet usage records to characterize site operations. The Team used a similar process for each visit, asking the same questions and starting the same conversations. After each site visit, we entered data into an in-house web-based tool for site visit data collection to compile notes and photos for aggregate analysis.

Site Costs

The Evaluation Team collected site-level costs from the Utilities via their annual SB 350 report. These costs include TTM and BTM costs. We paired these actual costs with other site-specific metrics like installed capacity, number of ports, vehicles in the VAP, and DAC status to develop summary statistics of site costs.

Deep Dives

The Evaluation Team engaged with participants from different sites for deep dive assessments across SCE, PG&E, and SDG&E territories. Our deep dives included detailed examinations of site usage metrics and assessments of vehicle and charger performance, user experience with EVs and EVSE, and site characteristics (e.g. electrical capacity and installation size) The deep dives allowed the Team to gather insights from projects that had potential to provide significant lessons for stakeholders. This data collection provided a secondary, more in-depth conversation between the Evaluation Team and site host than occurred during site visits. The Team based its site-specific questions about vehicle operations, reliability, and behavior on observed utility and session data.

The Evaluation Team used several criteria to select potential deep dives from MDHD sites evaluated during previous years. Sites of interest included those with significant demand, consumption, or installed charging capacity; a demonstrated ability to expand EV infrastructure; the presence of load management; unique vehicles or charging equipment; a large fleet size; and a fleet manager who was willing to participate.

We asked site hosts who had agreed to participate in the deep dive process to share additional site data and to discuss their experiences with the electrification process and operation of EVs. We also asked these site hosts to administer a survey to their vehicle operators to gauge feedback on EV and charger performance during normal operations.

Load Management Deep Dives

The Evaluation Team engaged with participants from sites across PG&E, SCE, and SDG&E's MDHD programs to identify barriers to implementing load management. As part of this process, the Evaluation Team guided site operators through self-assessing their operational proficiency, awareness of billing and energy trends, and experience working with NSPs.

To select candidates for load management deep dives, the Evaluation Team reviewed all MDHD sites that were evaluated in previous years to assess their potential utility bill savings with load management. The Evaluation Team then selected sites that could achieve utility bills savings of at least 25% if they were able to effectively implement load management.

The Team estimated potential utility bill savings using an analysis completed in EY2024 and described in the MDHD Grid Impacts section of each Utility chapter of the EY2024 Evaluation Report. Modeling was based on actual energy consumption trends and charging flexibility, or the ability for vehicles to shift charging to less costly billing periods without impacting operations. The Evaluation Team used data from charging sessions or other operational details from site visits to develop charging flexibility analysis, which was included in all prior evaluation reports. The methodology for this analysis is presented in the *Load Shifting Analysis Methodology* section.

The Team conducted 30-minute interviews with representatives from each candidate site to discuss knowledge of load management technologies, systems, and strategies; energy use trends and billing costs; and experience working with NSPs to help them adopt load management processes. Finally, the

Evaluation Team provided recommendations on pathways to explore and strategies to implement to shift energy consumption to lower cost time periods, which would reduce utility bills and emissions.

Interviews, Surveys, and Expert Opinions

Interviews

This section describes the approach, data sources, and analyses performed for the EY2025 Utility interviews. The Team interviewed staff at SCE, PG&E, and SDG&E to provide insight into program design and implementation and context to analysis outputs and findings.

The Team developed interview guides outlining a variety of key topic areas and questions for discussion to ensure that we covered each topic area during phone interviews with Utility program managers about their respective programs:

- Status updates and changes from EY2024 (and previous years)
- Program design
- Key milestones
- Key barriers to implementation and solutions
- Preliminary areas of success and lessons learned

The Evaluation Team tailored each interview guide based on information provided by the Utilities to ensure an effective use of time. A group of Team members with various areas of expertise conducted the interviews to effectively cover all relevant evaluation areas. The Team reviewed verbatim notes taken during each interview as the basis of our analysis and integrated our findings throughout the report.

The Evaluation Team also interviewed site hosts who withdrew from a PG&E, SCE, or SDG&E program (referred to as withdrawn fleet managers). In EY2023, the Evaluation Team collected data from withdrawn fleet managers via surveys; however, due to the low response rate for the survey and the small population, the Evaluation Team switched to interviews in EY2024 and EY2025. During the sample selection process, the Evaluation Team worked with the PG&E, SCE, and SDG&E program managers to ensure that we interviewed only fleet managers from sites that were eligible for and withdrew from the program—not from sites that applied but were not eligible. Interviewing only eligible sites allowed the Team to gather reasons for withdrawal that PG&E, SCE, or SDG&E might be able to address.

The interview was designed to address specific objectives, several of which were similar to the fleet manager survey:

- Identify the factors that facilitate successful fleet electrification and lessons learned
- Explore the benefits and costs of transportation electrification for fleets
- Gauge market impacts and trends and identify market barriers
- Understand the reasons for withdrawing from the program

For EY2025, the Evaluation Team attempted to reach all the sites that withdrew from the PG&E EV Fleet, SCE Charge Ready Transport, and SDG&E PYDFF programs. For initial outreach, we sent an email invitation

to withdrawn fleet managers to schedule an interview and sent several follow-up emails. The Evaluation Team attempted to contact by phone fleets that did not respond to the email and fleets without a listed email address.

Surveys

The Evaluation Team surveyed fleet managers of activated sites that participated in the program who had complete contact information. The purpose of the survey was to gather information to address several objectives:

- Identify factors that facilitated successful fleet electrification and lessons learned
- Explore the benefits and costs of transportation electrification for fleets
- Assess the experience of fleet managers with the program and infrastructure
- Gauge market impacts and trends and identify market barriers
- Assess program attribution

The Evaluation Team conducted the survey via an online survey platform, Qualtrics, and delivered the survey link via email to the site hosts through contact information provided by PG&E, SCE, and SDG&E. To encourage participation, the Evaluation Team sent several follow-up emails, reached out to nonrespondents by phone when phone numbers were provided, and followed up using additional points of contact through contact information collected from site visits. For EY2025, the Evaluation Team developed a sample frame of participants with available contact information and attempted to reach all sites in the sample frame.

Delphi Panels

To support the estimation of market effects, the Evaluation Team conducted Delphi panels to develop baseline electrification adoption curves.

A Delphi panel is a method of reaching a group consensus by aligning the range of opinions from a panel of subject matter experts. Certain components are particular to Delphi panels including the use of a group of anonymous experts with opinions collected through a series of two or three sequential, structured questionnaires. Opinions from the first round are summarized and provided to the experts for the second round so they can reevaluate their original responses. Panelists can either agree with the overall opinion or provide evidence or argument for their own opinion. The rounds continue until a majority consensus is reached. The Delphi method is particularly useful in cases with limited data. A panel moderator controls and manages interactions among the experts, with communication typically conducted remotely.

The Evaluation Team conducted two Delphi panels for the EY2025 report: one on the regional and long-haul tractor truck market, and the other on the yard truck (also commonly known as terminal tractor) market. The regional and long-haul tractor truck panel followed up on a previous Delphi panel conducted in EY2023. This was the first year that yard trucks were analyzed. For both panels, we recruited experts within each respective vehicle market to develop a consensus forecast of the market baseline for electrification in California through 2035.

The Evaluation Team conducted the two panels concurrently, recruiting a total of 13 panelists in February of 2026, who provided two rounds of structured feedback in March 2025. The Evaluation Team provided all panelists with the same background information, such as existing vehicle population statistics and projections of vehicles under the ACT regulation. In the first round, we asked the panel of experts to provide a forecast of the electric market share for their respective vehicle market assuming no intervention by the Utilities along with a rationale for the shape of their forecast. The Evaluation Team aggregated the first-round results, calculated the median forecast,[155] and shared the anonymized market predictions with the panel in the second round. The experts then reviewed all forecasts and had the opportunity to either agree with the median estimate or submit a new estimate. This process typically continues until convergence occurs (when over half of panelists agree). Both panels achieved convergence in the second round.

The Evaluation Team recruited experts from different organizations to provide input. The composition of the panels is shown in Table B-2. Because every expert and organization carries its own particular biases, it was crucial for the Delphi panels to feature individuals from a variety of backgrounds. We also required that experts on the panel have a background in and recent (in the last two years) experience with their respective vehicle market or transportation electrification policy in California and no conflicts of interest (financial or otherwise) that would impact their objectivity. We did not permit more than one expert from the same organization to participate in the panels.

Table B-2. Delphi Panelist Composition

Panelists	Academia	Nonprofit	Manufacturer	Industry	Third-Party Evaluator	Regulator	Total
Regional and Long-Haul Tractor Truck	1	1	1	2	1	2	8
Yard Truck	0	1	1	1	1	1	5

Analysis Methodology

The following subsections provide an overview of the analyses for the MDHD bundle. These analyses include determining the characteristics of counterfactual vehicles[156] and using these characteristics to assess grid impacts, petroleum displacement, GHG and criteria pollutant emissions reductions, and health impacts of MDHD programs. The Evaluation Team also estimated the TCO and addressed research objectives using data collected from site visits, Utility interviews, and surveys. As discussed below, we

[155] Although Delphi panels typically use an average of experts' responses, for this study we employed the median to mitigate the impact of outlier responses.

[156] Counterfactual data are used to establish a counterfactual fuel economy (miles per gallon) and vehicle emissions factors to estimate petroleum displacement, emissions reductions, and health impacts.

conducted additional calculations for the petroleum displacement, emissions reductions, and health impact analyses to consider these impacts on DACs in particular.

Site and Vehicle Target Graphs

In the Introduction Section and the Lessons Learned for the MDHD programs we present curves showing progress toward the Utilities' vehicle and site targets for each of the MDHD programs. The original and revised vehicle and site targets are shown in Table B-3 and Table B-4, respectively.

Table B-3. Original Vehicle and Site Targets

Program	Vehicle Goal	Site Goal	Program Launch	Program End
SCE Charge Ready Transport	8,490	870	May 2019	December 2024
PG&E EV Fleet	6,500	700	June 2019	December 2024
SDG&E PYDFF	3,100	300	November 2020	November 2025

Table B-4. Revised Vehicle and Site Targets

Program	Vehicle Goal	Site Goal	Program Launch	Program End
SCE Charge Ready Transport	8,490	500	May 2019	December 2026
PG&E EV Fleet	6,500	375	June 2019	December 2026
SDG&E PYDFF	3,100	300	November 2020	December 2026

The figures in the Evaluation Report show actual and projected VAPs and sites using solid and dashed lines for actual and projected values, respectively.

Vehicle Targets

1. **Full VAP for Contracted Sites (solid blue line).** This line reflects the full value of the VAPs associated with sites in the year in which the site was contracted. For example, if a site has a five-year VAP with 100 vehicles total, all 100 vehicles appear in the year the contract is signed.
2. **Projected Full VAP for Contracted Sites (dashed blue line).** This line projects line #1 into the future continuing a linear trend line for all historical years of data.
3. **Projected Deliveries of Vehicles for Contracted Sites (dashed purple line).** This line shows the Evaluation Team's projection of when vehicles will actually be delivered to the contracted sites. This line accounts for the lag between contract signing and activation and the lag between site activation and vehicle deliveries. This line uses the acquisition schedule in the VAP and accounts for differences in program design (i.e., the five-year VAP for PG&E EV Fleet and 10-year VAPs of SCE Charge Ready Transport and SDG&E PYDFF). We do not show an actual vehicle delivery line, because we conduct only one site visit per site (and therefore do not track actual vehicle deliveries each year).

Site Targets

1. **Actual Contracted Sites (solid blue line).** This line shows the number of contracted sites over time based on site performance data.

2. **Projected Contracted Sites (dashed blue line).** This line uses a linear trend line of the actual contracted sites to project the number of contracted sites into the future. We assume that 10% of contracted sites will withdraw from the programs prior to activation.
3. **Actual Activated Sites (solid purple line).** This line shows the actual number of activated sites. This line is slightly lower than line #4 and line #5 because of site withdrawals.
4. **Projected Activated Sites (dashed purple line).** This line shows a projection of activated sites based on a linear trend line of all activated sites to date.

Grid Impacts

The Team estimated electric grid impacts for MDHD on-road and off-road vehicles that consumed electricity from charging stations installed through MDHD programs. The following subsections describe the approach, data sources, and analyses performed to estimate grid impacts.

The Team collected, cleaned, compiled, and analyzed site-level, granular (15-minute interval) Utility AMI data and EVSP data. For the analysis we used the primary and secondary data sources shown in Table B-5.

Table B-5. MDHD Grid Impacts Data Inputs

Category	Source
Primary Data	Utility AMI data, charging session data from EVSPs, site details (capacity of various Utility and charging equipment), site visits, and surveys
Secondary Data	Time-varying Utility rates in effect at sites, historical CAISO data (demand, supply sources, renewable curtailments), and load management plans

We uploaded AMI and EVSP data to the data warehouse and calculated results using an internal Power BI dashboard. Foundational program analysis included total electricity consumption (kilowatt-hours) for on-road and off-road MDHD vehicles, and new demand (kilowatts) added to the grid. The Team established trends based on the proportion of electricity used during the highest cost period (defined as 4 p.m. to 9 p.m. daily) versus the rest of a 24-hour period. We calculated load factors based on usage and determined utilization rates based on the installed capacity and maximum demand for each site.

The Evaluation Team assessed daily and weekly charging behaviors and captured patterns that accounted for differences in weekday and weekend operations. We used load curves by vehicle category to identify trends of operating versus charging, factoring in periods when vehicles were not in full operation, had ongoing technical problems, or were not fully integrated with EVSE or other equipment.

We used CAISO data on electricity supply at different times combined with AMI data and EVSE charging session information to compare EV program load curves with overall system demand. The 24-hour load curves provided key insights into how the grid was impacted by each program.

The Evaluation Team assessed charging flexibility to determine the extent to which managed charging could increase benefits, such as by lowering site electricity costs (based on TOU rates and demand charges), reducing emissions by charging when lower-emissions resources power the grid, and minimizing the impact to the grid from new demand. Although the grid impacts analysis used data for all operational sites, the Team annualized AMI data to support analyses that included forecasts for petroleum

displacement and GHG and criteria pollutant emissions reductions among others. Through the annualization of AMI data, the Team identified the region of stable operation and used this data to generate a statistically representative full year of operation. We also grouped projects by age or year of activation to highlight progress to mature or consistent operations as fleets learn to operate EV ecosystems.

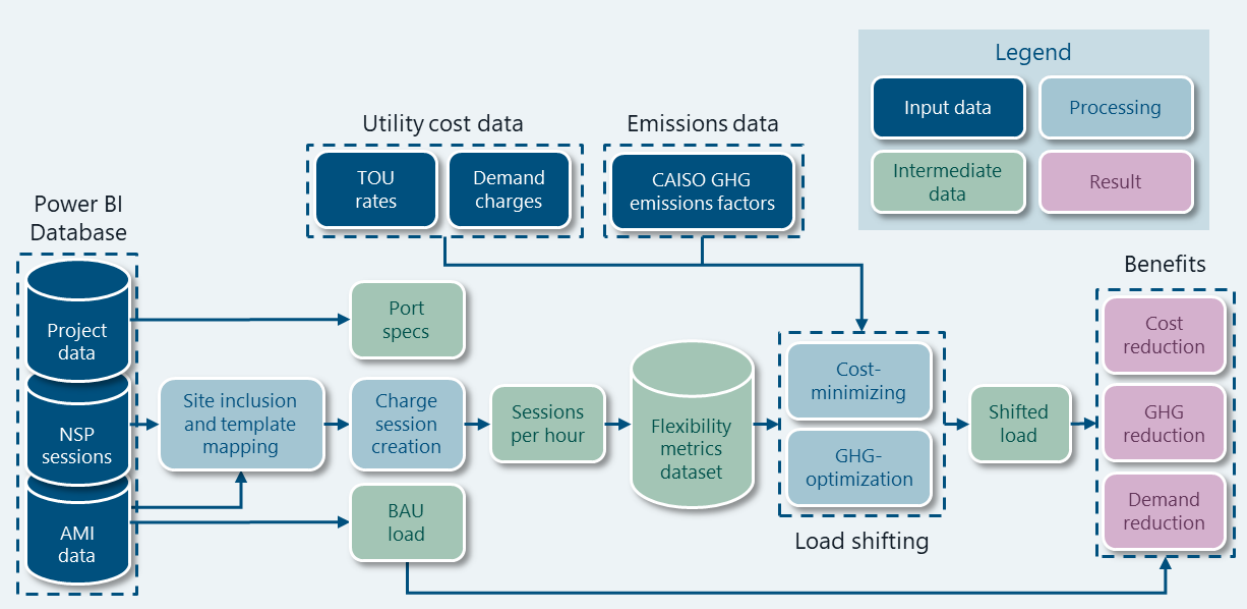
Load Shifting Analysis Methodology

Historical electricity usage data shows that sites participating in the Utility transportation electrification programs consume a substantial fraction of their daily electricity consumption during the high-cost peak period (4 p.m. to 9 p.m.) and underutilize lower-cost off-peak and super off-peak periods for charging—despite often being connected to chargers during these periods—incurring higher electricity consumption costs than necessary. This is particularly true for electric school bus fleets, which often replenish a small portion of the battery pack twice daily and spend a long time parked each day, allowing for considerable flexibility for charging. Off-peak charging periods tend to coincide with a lower average carbon intensity for grid electricity, suggesting the potential to reduce both costs and GHG emissions by load shifting charging sessions. Implementing load management software/controls that prioritize charging during off-peak periods would allow these sites to substantially reduce charging costs, lower carbon emissions, and support grid reliability by helping to balance the overall grid demand.

This section outlines the approach the Evaluation Team used to quantify the potential cost and GHG emissions impacts of load shifting for the MDHD transportation electrification programs. The Team analyzed consumption data from EY2025 and developed an optimization routine to reallocate charging energy consumption to lower-cost or lower-emissions times of day, accounting for each participant's flexibility to shift the charging load. Charging energy can be shifted to only intervals for which NSP session data indicate connected vehicles and additional or unused charging capacity. The Evaluation Team compared the resulting cost-optimized (or shifted) charging loads to the observed daily BAU charging loads to evaluate the cost-reduction and resulting emissions reduction potential of load shifting.

This subsection describes how the Team structured the load shifting optimization analysis. The results of this analysis are provided in the Load Shifting Analysis section of each of the respective Utility program sections. Figure B-1 provides a high-level summary of the analysis approach, including preparing data, applying exclusion filters, performing the load shifting optimization routine, processing the data, and analyzing the results.

Figure B-1. Data Preparation and Load Shifting Analysis Process Diagram



Load Shifting Data Preparation

To model load shifting, the Evaluation Team used data from NSPs, AMI provided by the Utilities, and first person anecdotes for each site. NSP data includes information about the charging sessions as recorded by the EVSE and NSP software, and AMI data contains the site energy consumption as measured at the utility meter in 15-minute intervals.

Power BI Data Extraction

The Evaluation Team cleaned and stored NSP and AMI data across available sites in a set of Microsoft Power BI database tables. For the load shifting analysis, we downloaded these tables (titled FACT_PROD_EVSP_Session and FACT_PMO_AMI_nonzero) in full, from the Power BI tool as comma-separated value (.csv) files. Table B-6 lists the operations data the Team used for the analysis.

Table B-6. Description of NSP and AMI source data tables

Table Name	Description	Fields Used	Used For
FACT_PROD_EVSP_Session	Data capturing information about each charging session recorded by NSPs	application_id station_id port_id flag_id session_start_datetime session_connection_time_fixed session_charge_duration_fixed session_energy_kwh	• Determining analysis dates for each project • Filtering and removing passenger cars • Determining each port's maximum power capacity • Conducting load shifting analysis
FACT_PMO_AMI_nonzero	Data capturing energy consumption in 15-minute intervals as captured by site-level AMI	site_ami_key TimeStamp_dt Demand_kW	• Determining BAU demand

Operations Data Filtering and Cleaning

The Evaluation Team included only data within EY2025 in its analysis and carefully reviewed the source data for each project. The Evaluation Team applied an additional set of filters to exclude certain NSP data:

- NSP sessions with a total energy consumption (ChargeKWH) near to zero
- NSP sessions with a start timestamp (SessionStartDateTime) equal to the end timestamp (SessionEndDateTime)
- NSP sessions with a missing value for LocationID or that failed certain other quality control checks (incorrect charge duration, incorrect demand values, or irreparable errors in the raw data)

Some NSP sessions follow the charging port's prior session with no time gap in between. These zero-gap sessions do not appear to leave time for a new vehicle to be plugged into the port and thus are likely reflecting the same vehicle continuing its prior charging session. To simplify the following analysis steps, we combined each sequence of zero-gap sessions into a single session with a shared session identifier and computed the combined session's total energy (ChargeKWH) across underlying sub-sessions.

Charging Port Power Capacity Estimation

The maximum potential power output of shifted loads for each charging port is determined not only by the nameplate power capacity of the charging infrastructure, but also by the charge acceptance characteristics of the connected vehicle(s) that are using the charger in a given time period. To infer a realistic potential maximum power output of each charging port, the Evaluation Team analyzed historical NSP data at each port and took the following steps to calculate each port's potential power output:

- **Step 1.** For each session at each port, the Team used the total energy output (taken from the ChargeKWH field) and the total charging duration (taken from the SessionStartDateTime and SessionEndDateTime fields) to compute an average power output per session. If the session's maximum power demand (ChargeMaxDemandKW) recorded in the NSP data table was higher than the computed average, we used the recorded value.

- **Step 2.** For each port and for each calendar month of EY2025, the Team computed the monthly 80th percentile value of average power output across all sessions that month and used that value as the port's potential power output for that month.

The potential power output metric is intended to incorporate the limitations of both the charger technology and the charge acceptance characteristics of specific vehicles using the port or other operating concerns that may vary over time.

Market Sector Template Creation for Additional Site Inclusion

To maximize the number of projects we could include in the analysis, we included some sites with AMI data but no NSP data (which EY2025's load shifting analysis relied on) and developed an approach to build market sector templates from available NSP data. For each market sector, the Team aggregated all EY2025 NSP data that passed the quality checks described above to produce a "market sector template" consisting of several metrics:

- **Maximum Charging Speed:** The average across charging ports of each port's maximum charging speed weighted by the port's total annual kilowatt-hours
- **Average Session Energy:** Average kilowatt-hours per session
- **Average Session Plug-In Duration:** Average plug-in duration for sessions at each time of day and day of the week, weighted by each session's kilowatt-hours—for market sectors with insufficient time-of-day and day-of-week data, the Evaluation Team used a combination of time of day and day of week type (weekday versus weekend) or simply time of day.

These templates, which define typical behavior for each market sector, enabled the Team to convert AMI data into a reasonable approximation of discrete charging sessions for sites without NSP data. The first step in this process was to divide daily energy consumption by the market sector's average session energy (rounding up) to estimate how many charging sessions occurred that day. Next, we chose charging session start times based on the times of day with the largest increase in AMI load. Finally, we assigned a plug-in duration to each estimated charging session based on the session's starting time and day of week.

After creating charging sessions for each site, the Team applied the load-shifting optimization step we applied to available NSP session data. For months with more charging session data than available NSP data, we used data from our estimated charging sessions instead.

Flexibility Metrics Dataset Creation

The Evaluation Team combined information across NSP sessions for each site into a flexibility metrics dataset, which includes the following variables for each 15-minute interval within each project's analysis date range:

- **Observed (BAU) project-level energy demand from the AMI and NSP tables:** NSP demand for each site is summed across site NSP sessions that overlap with the interval. To allocate each NSP session's energy across intervals, we assumed a constant charge rate for the duration of the session.
- **Total unique ports that were connected**
- **Total unique sessions that were connected**

- **Total hours of overlapping charge sessions across connected ports:** For example, if only one port has a connected vehicle for the full 15-minute interval, the site would have a total of 0.25 overlapping session-hours in that interval. On the other hand, if four ports are connected for the full duration of a 15-minute interval, the site would have 1.0 overlapping session-hours in that interval.
- **Maximum potential energy demand:** This value represents the sum of the estimated charging power capacity of each of a site's ports multiplied by that port's overlapping session-hours in the 15-minute interval.

The resulting flexibility metrics dataset formed the basis for the load shifting optimization.

Utility Cost and Emissions Data Preparation

The Evaluation Team prepared a dataset of TOU rates and demand charges for each participating Utility using publicly available data regarding rate structures for the Utility's MDHD transportation electrification program. We converted each set of rates from TOU bins into 15-minute intervals of electricity rates per kilowatt-hour to match the resolution of the AMI data. To simplify downstream analysis, we made a simplifying assumption for the volumetric (dollar per kilowatt-hour) component of utility rates by using each site's maximum demand level in EY2025 (maximum-kilowatt 15-minute interval) to assign a rate category for the project. For example, a PG&E site falls into BEV-1 or BEV-2 if its peak demand is below or above 100 kW, respectively. We also incorporated demand charges from public utility rate data into the EY2025 analysis.

Carbon intensity values (ton of CO_2-equivalent emissions per kilowatt-hour of delivered energy [ton-CO_2e/kWh]) from GHG emissions were taken from CAISO's 2025 historical average emissions in 15-minute timesteps. To reduce the effect of random variations due to weather events or other irregular occurrences, the Team averaged carbon intensity values across each combination of month and day type (weekday versus weekend) and applied these average values to the analysis.

Load Shifting Optimization Model

For each project, the Team merged the flexibility metrics dataset on unit (volumetric) TOU energy costs, demand charges, and emissions factors to produce a table with both charging potential (maximum potential energy demand in each 15-minute interval) and objective values for optimization (costs or emissions). We then input this table into a mixed-integer linear programming model to optimize each site's load shifting considering peak demand reduction. The Evaluation Team optimized two distinct objective functions, producing two sets of shifted load curves:

- **Cost minimization objective:** load is shifted to minimize each month's total estimated utility costs, including TOU energy rates and demand charges (assessed monthly).
- **GHG minimization objective:** load is shifted to minimize tons of GHG attributable to the site's charging load using the CAISO carbon intensity values described above.

For each of those objective functions, the optimization algorithm computes a mathematically optimal shifted load curve for each month of the year for each site, incorporating following constraints:

- **Energy conservation:** Daily total energy consumption (measured from 6 a.m. to 6 a.m. the following day) must remain unchanged when the load is shifted.
- **Flexibility:** The energy consumption in each 15-minute timestep may not exceed the flexibility metrics used to define the flexibility metrics dataset.
- **Peak demand increase:** To ensure that load is not shifted in a way that would drastically increase a site's peak demand (which could require additional infrastructure buildout), each month's shifted peak demand may not exceed 150% of its BAU peak demand.
- **Demand charge computation:** A separate set of constraints determines monthly peak demand and assigns it a cost that matches posted utility rates.

Performing optimization for each site, month, and objective function, produces a dataset of 15-minute shifted interval data that can be compared with BAU outcomes. These results are summarized in total across each site (i.e., percentage reduction in costs equals total BAU cost in comparison to total optimized cost, summed across days). This approach tends to reduce the impact of low-demand days (such as summer and weekend days for school buses) and prioritize the impact of high-energy days. As such, it is weighted in a similar manner as the volumetric component of each project's energy bill.

Counterfactual Development

The Evaluation Team identified the market sectors in each Utility program and the counterfactual vehicle and fuel type associated with each market sector. A counterfactual vehicle type is the vehicle type that the fleet would have used in the absence of the program.

Rather than assess the composition of each legacy fleet (conventional ICE vehicles displaced by the program), we established a generic counterfactual vehicle type. In total, the Evaluation Team used 18 counterfactual vehicle types defined by weight class and fuel type. The Team assigned all sites an initial counterfactual vehicle type based on Utility program applications. We then refined this information based on additional vehicle information included as part of the VAPs participants submitted to Utilities.

Each counterfactual vehicle type has a corresponding fuel economy (miles per gallon) for on-road vehicles or fuel consumption (gallons per hour) for off-road equipment as well as specific emissions factors (GHGs and criteria pollutants). We also determined the electricity consumption rate used by the corresponding EV (in kilowatt-hours per mile for on-road vehicles and kilowatt-hours per hour for off-road equipment).

To characterize counterfactual vehicles, the Evaluation Team processed Emissions Factors (EMFAC) data for on-road vehicles and Off-Road Inventory Online (ORION) data for off-road vehicles as default sources for efficiency and emissions. We input these tables into the Cadmus data warehouse. When electricity consumption rates were not available for a particular vehicle or equipment type, we used supplemental data sources to determine an appropriate rate. Table B-7 shows the primary and secondary data inputs the Evaluation Team used for this analysis.

Table B-7. MDHD Counterfactual Data Inputs

Category	Source
Primary Program Data	Utility VAPs, site visits, fleet manager surveys, and OEM interviews
Secondary Data	CARB EMFAC and ORION (default source for efficiency and emissions), Priority Review Projects fleet data (from the final report)[a] other demonstration reports (from CARB, CEC, and the National Renewable Energy Laboratory), MDHD vehicle registration data as available, Department of Motor Vehicles (DMV) Motive Power Report, and California DMV Motive Fuels Report

[a] Energetics Incorporated. April 2021. California Investor-Owned Utility Transportation Electrification Priority Review Projects: Final Evaluation Report. www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/sb-350-te/california-te-prp-final-evaluation-report-presentation.pdf

The final output is a lookup table that maps all the relevant market sectors to each of the CPUC-defined market sectors and the associated counterfactual vehicle type (such as electric Type C school bus and diesel Type C school bus).

Petroleum Displacement

For this analysis, the Evaluation Team estimated the reduction in counterfactual vehicle fuels compared with the electricity usage attributable to the MDHD programs. Expected fuel types and typical end uses included diesel (for trucks and school buses), CNG (for transit and shuttle buses), propane (for forklifts), and gasoline (for trucks and vans). Based on the *Counterfactual Development* analysis, we converted all displaced fuels to the equivalent amount of petroleum-based fuel in diesel-gallon equivalent (DGE) units.

The Team converted the electricity that EVs used (based on Utility-provided AMI data) to petroleum displaced using an electricity consumption rate to calculate EV miles traveled or equipment hours of use and assumed that the counterfactual ICE vehicle would have traveled that number of miles or have been used for that number of hours in the absence of the MDHD programs. To calculate petroleum displacement in gallons per site, we divided the ICE vehicle miles or hours by the counterfactual on-road vehicle's fuel economy (miles per gallon) or multiplied by the off-road equipment's fuel consumption (gallons per hour). We then converted the amount of petroleum displaced to DGEs for ease of comparison. Then the Team calculated the petroleum displaced by each MDHD program by Utility, DAC, and market sector.

Data inputs included Utility program data (market sector and vehicle type), data from site visits and fleet manager surveys, historical counterfactual vehicle fuel consumption, data from EMFAC and ORION databases, Utility AMI data, and EVSE charging session data. Table B-8 shows the data collection categories and sources.

Table B-8. MDHD Petroleum Displacement Data Collection

Category	Source
Primary Data	• Utility program data (on vehicle types, quantities, and other details) • Utility electric AMI data (in 15-minute intervals) • EVSE charging session data • Site visit and survey data for site-specific inputs • EV fleet make/model • Daily/annual vehicle utilization (miles) and schedules • EV charging schedules • Counterfactual fleet fuel type and average fuel economy/historical fuel usage • Estimated annual idling hours per vehicle
Secondary Data	EV and counterfactual ICE fuel efficiency (from counterfactual EMFAC lookup table and other sources)

For this analysis the Team leveraged the Cadmus data warehouse and counterfactual lookup tables, Power BI dashboard, and other sources and outputs from the *Grid Impacts* analysis. The Team used AMI data as the basis for these calculations. Table B-9 shows the analysis steps.

Table B-9. MDHD Petroleum Displacement Analytical Steps

Step	Description
Identify counterfactuals and secondary data	For each vehicle type, identify gallons per mile or gallons per hour and kilowatt-hours per mile efficiency from the following sources: • MDHD counterfactuals • EMFAC/ORION for both EV and ICE real-world efficiencies
Identify EV energy consumption	Identify annual kilowatt-hours consumed by EVSE at each site from grid impacts analysis
Account for charging losses	Use 15% loss from grid to vehicle battery for vehicle charging; assume no loss for electric truck refrigeration units
Calculate vehicle miles or hours (for off-road applications)	Calculate EV miles or hours based on kilowatt-hours consumed and vehicle efficiency
Estimate petroleum displacement	Estimate petroleum displacement based on ICE vehicle miles or hours and efficiency, converted to a DGE

GHG and Criteria Pollutant Impacts

The MDHD programs are expected to reduce emissions of GHGs and criteria pollutants as EVs replace fossil fuel–powered on-road and off-road MDHD vehicles. This section describes the approach, data sources, and analyses The Evaluation Team performed to estimate these reductions.

The Team first calculated the reduction of GHG and criteria pollutant emissions from the petroleum displaced by the EVs incented through the programs.[157] The GHG emissions estimates included CO_2, N_2O,

[157] The Evaluation Team counted tailpipe emissions for the counterfactual vehicles and electricity grid emissions for EVs. We did not consider upstream emissions for the counterfactual vehicles (such as petroleum refining). Additionally, we did not include emissions from brakes and tires for the counterfactual vehicles and EVs.

and CH_4. The criteria pollutant reductions we analyzed included $PM_{2.5}$ and PM_{10} and incorporated brake and tire wear particulate matter for EY2025, as well as CO, NO_X, and oxides of sulfur (SO_X). The Team also estimated the reduction of ROGs, which are not criteria pollutants but contribute to the formation of ground-level ozone, which is a criteria pollutant.

Next, the Team examined the increase in emissions attributed to the electricity used by the EVs. We calculated the emissions from EV electricity use by examining the emissions profile of the grid at the time of charging using the published CAISO grid mix at five-minute intervals. Because the electric grid emissions profile varies substantially by time of day and season, we estimated reduction using actual 8,760-hour load curves based on Utility AMI meter data.

The difference between the counterfactual vehicles' petroleum emissions and the EVs' electricity emissions is the net reduction in emissions for the more-global-scale pollutants (GHG, NO_X, and SO_X). For criteria pollutants with localized health effects such as CO, PM, and ROG, we present the emissions as an absolute reduction from the counterfactual.

The Evaluation Team used the GHG and criteria pollutant inputs shown in Table B-10 regarding electricity usage, resource mix, emissions, vehicle types, and petroleum displaced.

Table B-10. GHG and Criteria Pollutant Data Inputs

Category	Unit	Source
Site-level AMI data in 15-minute intervals	kWh	Utility AMI (~1 month delay between measurement and reporting)
Overall electricity demand by five-minute interval	MW	CAISO demand (real time)
CO_2 grid emissions by five-minute interval	MT	CAISO emissions (real time)
Resource mix by interval	percentage by generator fuel	CAISO supply (real time)
NO_X, SO_X, CH4, and N_2O emission rates	g/kWh	EPA eGRID (2023)
CO_2 emission rate	kg/kWh	EPA eGRID (2023)
CO_2-equivalent emission rate	kg/kWh	EPA eGRID (2023) as derived from emission rates above
Vehicle tailpipe emissions (CO_2, CH_4, N_2O, CO, NO_X, PM_{10}, $PM_{2.5}$, SO_X, and ROG) by vehicle and fuel	g/mile	CARB EMFAC (2021 v.1.0.2 methodology extracted Feb 2025)
Vehicle type (vehicle classification code for linkage to emission tables)	standard category	Evaluation Team analysis in *Petroleum Displacement* section
Petroleum use by month	unit measure for fuel type	Evaluation Team analysis in *Petroleum Displacement* section
Petroleum fuel type	fuel type	Evaluation Team analysis in *Petroleum Displacement* section
Petroleum fuel energy content	MMBtu/unit	U.S. DOE AFDC

The analysis comprised four steps. The Team used the CAISO application programming interface, the EMFAC dataset, and the EPA's eGRID data to perform this work:

1. **Counterfactual emissions:** We determined emissions from counterfactual vehicle fuel usage using EMFAC emissions data for specific displaced fuels (in gallons/mile) along with the determined miles driven from the petroleum displacement methodology.
2. **Electricity emissions:** We used CAISO five-minute demand and resource mix data reported by zone to establish an emissions record for each pollutant. We averaged five-minute interval emissions data, applied this to each 15-minute AMI interval, and applied the CAISO-specific emissions factors for that resource provided by the eGRID dataset.
3. **GHG calculation:** We used the United Nations IPCC GWPs for CO_2 equivalence (CO_2e) on a 100-year timeframe based on the IPCC AR5. We used GWP-100 factors of 28 for CH_4 and 265 for N_2O. Equation 1 presents the GHG calculation based on CO_2e:

Equation 1. GHG Calculation

$$CO_2e = CO_2 + 28 * CH_4 + 265 * N_2O$$

4. **GHG and criteria emissions reductions:** The overall reduction in GHGs, NO_X, and SO_X is net of annual emissions from the displaced counterfactual fossil fuel equipment and the electricity consumed by the adopted electric equipment. The overall reduction in $PM_{2.5}$, PM_{10}, CO, and ROG is represented by the annual emissions from the counterfactual vehicle, as these pollutants present localized effects on populations rather than the more globalized effects of the other pollutants. The Team calculated these emissions reductions for sites both inside and outside DACs.

In alignment with the CPUC IRP process, the California Utility grid is expected to further reduce power plant emissions in future years. The Evaluation Team determined the hourly mix of electricity in future years from the most recent IRP RESOLVE models available and applied the changing mix out to 10 years of operation for each site. We treated the emissions factors for these resources as static using the most recent eGRID dataset for CAISO resources.

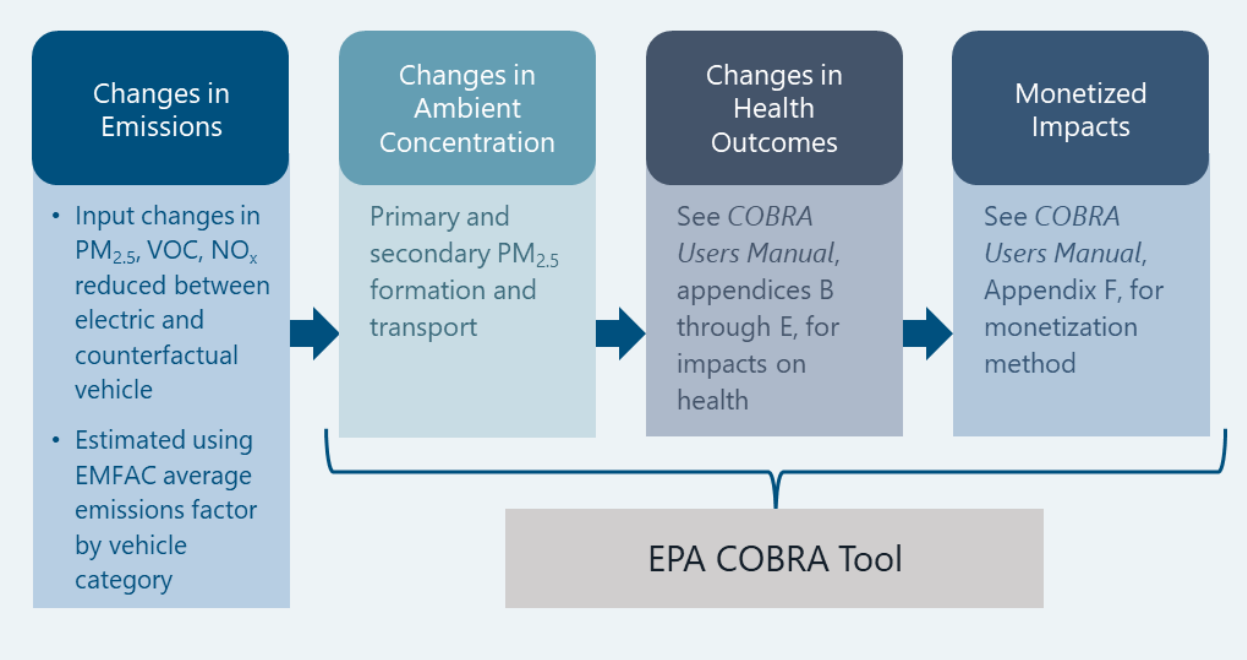
Health Impacts

As EVs replace traditional ICE vehicles, petroleum-based fuels are displaced. These displacements reduce GHG and air pollutant emissions, which may lead to health benefits in regions where EVs are adopted. To understand the effects of the programs on air pollution and related health benefits, the Evaluation Team estimated the monetized value of health benefits of each individual Utility-funded site by running the emissions reductions through the EPA's COBRA. As part of this analysis, we also examined health impacts on DACs. For Liberty, PG&E, and SCE, DACs are identified in the California Communities Environmental Health Screening Tool, CalEnviroScreen, developed by California's Office of Environmental Health Hazard

Assessment. SDG&E uses a service territory definition of DAC.[158] This section describes the approach, data sources, and analyses performed to estimate health impacts associated with the MDHD programs.

The Evaluation Team used a four-stage methodology shown in Figure B-2.

Figure B-2. Four-Step Process for Estimating Health Impacts by Census Tract



Step 1: Changes in Emissions. The Evaluation Team estimated changes in emissions by annualizing emission reductions by site for EY2025 in tons for $PM_{2.5}$, VOCs, and NO_x. The Team aggregated emissions reductions by county and used those as inputs into COBRA, which uses several fields:

- **Sector** – Highway or off-highway vehicles
- **Subsector #1** – Diesel for most vehicle applications
- **Subsector #2** – Highway or non-road
- **Discount rate** – 2% assumed, which reflects the interest rate consumers might earn on government-backed securities

Using the COBRA desktop application, the Evaluation Team uploaded the annual reductions in emissions for $PM_{2.5}$, VOCs, and NO_X, and the tool output estimates as shown in Table B-11. In this analysis VOCs are assumed to be the same as ROGs, which are the output from EMFAC.

[158] As per AL 2876-E, SDG&E found that only 27 census tracts in its territory were considered DACs using the top quartile in the CalEnviroScreen statewide definition. However, the service territory definition is broader and produced a calculated 180 DAC census tracts in SDG&E service territory.

Table B-11. Mapping of Vehicle Types to Sector and Subsectors

Vehicle Type	Sector	Subsector #1 (Counterfactual Fuel Type)	Subsector #2 (Counterfactual Vehicle Type)	Discount Rate
LDV (at public charging sites)	Highway	Gasoline fuel	Light duty	2%
Airport GSE	Off-Highway	Non-road diesel	Airport service	2%
Cargo handling equipment	Off-Highway	Non-road diesel	Industrial	2%
Forklift	Off-Highway	Non-road diesel	Industrial	2%
Heavy-duty vehicle	Highway	Diesel fuel	Heavy duty	2%
Medium-duty vehicle	Highway	Diesel fuel	Heavy duty	2%
Other heavy-duty vehicle	Highway	Diesel fuel	Heavy duty	2%
Port cargo truck	Highway	Diesel fuel	Heavy duty	2%
School bus	Highway	Diesel fuel	Heavy duty	2%
TRU	Highway	Diesel fuel	Heavy duty	2%
Truck Stop Electrification	Highway	Diesel fuel	Heavy duty	2%
Transit bus	Highway	CNG	Heavy duty	2%

Step 2: Changes in Ambient Concentration: COBRA has a feature that uses emissions reductions to estimate the change in ambient concentration. The tool also accounts for transport and transformation of the pollutants (for example, into ozone).

Step 3: Changes in Health Outcomes: COBRA uses epidemiological models to estimate the health impacts of changes in emissions at the county level. COBRA's estimates reflect the current scientific thinking on the relationship between particulate matter and human health and the economic valuation of these health effects. In particular, the EPA draws from the Integrated Science Assessment for Particulate Matter.[159] The EPA's methodology for characterizing health impacts has been reviewed by two National Academy of Sciences panels and multiple EPA Science Advisory Boards. Because the health impacts of air pollution and approaches to value health impacts are areas of active research, the selection of studies used in COBRA may evolve over time, as new evidence and studies emerge. More information is available in the online COBRA documentation.[160] COBRA estimates health impacts for all 3,033 counties in the United States (because of the transport of pollutants).

Step 4: Monetized Impacts: COBRA estimates the economic value (in 2023 USD) of the change in health impacts from emissions changes at the county level. These values are converted to current year dollars using a multiplier from the U.S. Bureau of Labor Statistics.[161] Economic value is estimated differently depending on the health impacts. These estimates could include avoided lost wages, avoided medical costs, or the amount people are willing to pay to avoid a negative health impact (such as respiratory

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159 U.S. EPA. Last updated January 5, 2026. "Integrated Science Assessment (ISA) for Particulate Matter." www.epa.gov/isa/integrated-science-assessment-isa-particulate-matter

160 U.S. EPA. Last updated February 11, 2026. "Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool." www.epa.gov/cobra/users-manual-co-benefits-risk-assessment-cobra-screening-model

161 U.S. Bureau of Labor Statistics. 2026. "CPI Inflation Calculator." www.bls.gov/data/inflation_calculator.htm

symptoms). Monetizing impacts can also follow a value of a statistical life (VSL) approach, which uses value-of-life studies to determine a monetary value of preventing premature mortality. COBRA reports both a low impact and a high impact, representing uncertainties in the estimates. The low estimate represents results based on an evaluation of mortality impacts of $PM_{2.5}$ by the American Cancer Society.[162] The high estimate represents results based on the Harvard Six Cities mortality study.[163] Rather than average the results of these studies, the EPA's standard practice has been to report the estimated change in mortality separately as low and high values.

Site Visits

The Evaluation Team visited sites that were activated during EY2025 to provide quantitative and qualitative infrastructure insights. This section describes the approach, data sources, and analyses performed for these site visits.

The Team used detailed notes and photos taken during each site visit as well as data provided by the Utilities. After each site visit, the Team compiled the notes and photos and entered data into the Arkenstone data collection platform. Arkenstone is the custom data management platform developed by Cadmus that houses site visit data. We used these data to support grid impacts and petroleum displacement analyses, because these analyses rely on site-specific energy consumption, which can be impacted by the reliability of charging systems for EVs and by the change in energy consumption from integrating EVs into a fleet's operation.

The Team then analyzed the data to document several types of quantitative and qualitative insights:

- Confirm the number and type of conventional vehicles and fuel types to support counterfactual analysis adjustments in future evaluation years
- Confirm the installed charging hardware, whether the site is using an EVSP, and the number and type of EVs delivered compared with the vehicle and EVSE acquisition plans provided by the Utility program data to determine the following information:
  - Total installed charging capacity (kW)
  - Expandability, which may be indicated by the size of transformers, details of service panels (amperage and space for circuit breakers), preinstalled conduit, available parking, and other vehicle types used by fleets
- Visually identify variables leading to final design and construction decisions (such as whether transformers are new, upgraded, or preexisting) with support from on-site hosts or Utility staff for interpreting site costs under TCO analysis

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[162] Krewski, Daniel et al. May 2009. "Extended Follow-Up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality." Res Rep Health Effects Institute (140): 5–114. pubmed.ncbi.nlm.nih.gov/19627030/

[163] Lepeule, Johanna, Francine Laden, Douglas Dockery, and Joel Schwartz. March 28, 2012. "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009." Environmental Health Perspective 120(7): 965–970. www.ncbi.nlm.nih.gov/pmc/articles/PMC3404667/

- Confirm co-funding for vehicles and charging infrastructure that helps address ratepayer cost benefits
- Explore lessons learned, challenges, and operability factors (for EVs and charging hardware) that support the site utilization rates:
  - EV charging infrastructure (software and hardware)
  - Vehicle Operations and Maintenance Staffing
  - Vehicle duty cycle, including routing, cargo and passenger loads
- Compare site visit findings to information provided by each Utility Program Management Office (vehicle/EVSE acquisition plans) and PAC meetings

Site Costs

The Evaluation Team used site-level cost data provided by the Utilities to compile summary statistics of the TTM and BTM costs described below:

- **TTM:** Utility-sponsored costs to construct utility-owned TTM infrastructure taken from SB 350 reporting data provided by the Utilities.
- **Ratepayer BTM:** Either Utility-sponsored costs to construct utility-owned BTM infrastructure or the incentive/rebate amount paid by the Utility for customer-owned infrastructure.
- **All-In BTM:** Either Utility-sponsored costs to construct utility-owned BTM infrastructure or costs estimated using a regression on available costs from sites with cost data.
- **Ratepayer EVSE:** The EVSE rebate amount from the Utility.
- **All-In EVSE:** The full cost of the EVSE equipment and installation assuming L2 ports cost $3,000 per port and DCFC ports cost $45,000 per port for simplicity.

Cost calculations also include the following assumptions:

- The port counts used in the cost-per-port calculations reflect the number of ports reported from site visits. If a site visit did not occur, the Team used the port counts reported by the Utility.
- The vehicle counts used in the cost-per-vehicle calculations are taken from site VAPs.
- The installed capacity values used in the cost-per-kilowatt calculations are the site capacities observed during site visits. If a site visit did not occur, the Team used port capacity totals reported by the Utility.

Co-Benefits and Co-Costs

The Evaluation Team collected information about co-benefits and co-costs for fleet managers through fleet manager surveys, interviews and fleet driver surveys. For the fleet manager surveys specifically, the Evaluation Team asked both closed- and open-ended questions to understand which co-benefits and co-costs fleet managers experienced. The survey was designed to build upon data the Evaluation Team had collected in the previous year by using the results to expand the number of co-benefits and co-costs evaluated and retaining a similar survey structure year over year. Given that some fleets have been operating for a short time, the Evaluation Team took a qualitative approach to assessing the value of co-benefits and co-costs, asking respondents to choose a rating of significant benefits, some benefits, or no

benefits. Additionally, the Evaluation Team worded survey questions to focus on what respondents expected, not what they experienced, because many of the co-benefits are felt by EV drivers and local communities and not by the fleet managers specifically.

Deep Dives

Analysis for deep dives included synthesis of multiple data sources such as surveys, interviews, virtual presentations, and follow-up activities for selected sites.

- **Fleet Manager Interviews:** The Team interviewed fleet managers via phone in the fall. We focused the interview questions on EV and charger performance, satisfaction with EVs and chargers, and the vehicle acquisition process. During each interview, we also requested data from fleet managers on historical fuel and mileage logs, vehicle telematics data, and historical maintenance costs.
- **Driver Surveys:** The Team distributed driver surveys after discussing logistics with the fleet manager during the interview. At two surveyed sites, we supplied PDF copies of surveys and questions per the request of the fleet managers, who printed and distributed the surveys to drivers. The surveys covered the driver's experience, perceptions of the benefits of electrification, and operational impacts.
- **Operational Analysis Presentation:** If requested by the fleet manager, the Evaluation Team scheduled a one-hour virtual meeting with each deep dive participating fleet to present the results of the analysis (based on at least the past 12 months of operational data).
- **Activities:** Sites with a significant change in operations (such as sites that added a significant number of vehicles or implemented load management strategies) may require an extended deep dive analysis for another year. The Team asked these fleet managers to participate in a brief follow-up phone interview starting in EY2024 to enable an iterative dialogue.

Load Management Deep Dives

Analysis for load management deep dives included synthesis of multiple data sources, including site visits, fleet interviews, and project documentation for selected sites.

- **Fleet Manager Interviews:** The Team interviewed more than 40 fleet managers via phone in Q1 2026. We focused interview questions on site awareness of load management, fleet fuel costs, and utility bills, as well as any reasons why sites were not currently participating in load management. The Evaluation Team gave short presentations of each fleet's billing and load data during each interview followed by high-level discussions of the impacts that load shifting could have on the fleet's electricity costs and operations.

The Evaluation Team anonymized, quantified, and summarized the results of these interviews in a final EY2025 report that examines the observations, trends, and sentiments captured as part of our interview process.

Net Impacts

In this evaluation, net impacts refers to the combined positive and negative impacts from the Utility programs on the EV market after accounting for factors like freeridership, participant spillover, and market

effects. Net impacts are an important metric for conveying the overall efficacy of the Utility programs to support efficient allocation of resources and inform future program planning. The Evaluation Team uses several different analyses to capture net impacts, each of which we describe below.

Conceptual Overview

Figure B-3 illustrates the relationship between the naturally occurring baseline, spillover, freeridership, and market effects. A natural market baseline is the naturally occurring EV adoption in the absence of the Utility programs. Once the Utilities launched their programs in 2018 and 2019, the actual EV adoption rates increased above the natural market baseline due to a complex set of market effects, resulting in faster and/or higher levels of EV adoption. Estimating market effects requires knowing the actual adoption rate, program participant net impacts, and natural market baseline.

Figure B-3. Market Effects: Acceleration and Transformation



Natural Market Baseline

To estimate the natural market baseline, the Evaluation Team conducted two Delphi panels with experts in various market sectors who took two rounds each to develop a consensus forecast of the market share baseline for the electrification of those sectors in California through 2035. The baseline assumes no market interventions by the electric Utilities. The sectors for the EY2025 report were yard trucks and regional and long-haul tractor trucks.

The panelists provided their input through an online survey, which the Evaluation Team programmed to capture panelists' predictions of electrified market share in 2025, 2027, 2029, 2031, 2033, and 2035. The online survey allowed panelists to see their forecasted adoption curve generated in real time and adjust their responses dynamically.

In the first round, we asked experts to provide a forecast of their respective market sector's EV market share assuming no Utility interventions, along with a rationale for the shape of their forecast. The Evaluation Team aggregated the first-round results, calculated the median forecast, and shared the anonymized market predictions with the panel in the second round. The experts reviewed all forecasts and could either agree with the median estimate or submit a new estimate. Both panels reached convergence, meaning more than half agreed, in the second round.

While the main purpose of these Delphi panels was to develop a natural market baseline forecast, the panelists' written rationales contained valuable qualitative information. We consolidated this information into a summary of factors panelists believe will accelerate or impede electrification in California.

The panelists also considered the impact of applicable CARB regulations, including ACT, with some forecasting trajectories below the CARB requirements (suggesting either incomplete compliance or compliance through alternative technologies) and some forecasting trajectories consistent with full compliance.

MDHD Fleet Manager Self-Report NTG Methodology

The Evaluation Team's approach for MDHD program enhanced self-report NTG analysis relied partly on data obtained via surveys with key site decision-makers such as program participating fleet managers. The Team estimated freeridership and spillover ratios for each program to determine program-specific self-report NTG ratios using the following calculation:

$$NTG\ Ratio\ =\ 1\ -\ Freeridership\ Ratio\ +\ Participant\ Spillover\ Ratio$$

Freeridership is the percentage of participants who report that they would have adopted the MDHD EVs in the absence of the MDHD make-ready program. Participant spillover in the MDHD fleet sector is the increase in participants' EV adoption beyond direct participation in the program that the Team can attribute to their experience participating in the MDHD program.

For the MDHD fleet manager self-report freeridership analysis, the Team assessed three aspects of program participation:

- **Accelerated electrification from the program:** The extent to which the make-ready and infrastructure savings motivated fleet managers to purchase MDHD EVs sooner than they had originally intended before learning about the MDHD program.
- **Awareness of the program:** The extent to which fleet managers were aware of the program at the time they decided to implement their transportation electrification project.
- **Influence of the program on electrification:** The degree of influence the program had on fleet managers' decision to implement the transportation electrification project.

For the MDHD fleet manager participant spillover analysis the Team assessed three aspects of program participation:

- **Additional electrification after program participation:** The extent to which fleet managers continued electrifying their fleet after participating in the MDHD make-ready program without receiving additional incentives from the MDHD program.
- **Use of outside funding:** The extent to which participating fleet managers received financial support from any other organization for their additional fleet electrification projects.
- **Influence of the program on additional electrification:** The degree of influence MDHD program participation had on fleet managers' decisions to continue electrifying their fleet without Utility program support.

Self-report information was a core component of the Team's analysis of net effects directly attributable to MDHD programs. The Team used the CPUC nonresidential customer self-report NTG framework as the basis for developing the MDHD fleet manager NTG methodology approach.[164] The nonresidential NTG methodology that has been in use since the 2006–2008 energy efficiency program evaluation cycle addresses the unique needs of nonresidential customer projects developed through energy efficiency programs offered by the four California Utilities and third-party implementers. This method relies exclusively on the standardized self-report approach to estimate site- and domain-level NTG ratios, because other available approaches and research designs are generally not feasible.

The Evaluation Team developed the MDHD self-report NTG methodology in accordance with the relevant EM&V guidelines, including the California Energy Efficiency Evaluation Protocols (April 2006) and the most recent updates to the nonresidential NTG framework, which incorporated an alternative to a legacy

[164] California Public Utilities Commission, Energy Division. February 20, 2015. Methodological Framework for Using the Self-Report Approach to Estimating Net-to-Gross Ratios for Nonresidential Customers.

program PAI scoring component (PAI-1 score) of the core NTG calculation.[165] For the purposes of this MDHD self-report NTG methodology, the Evaluation Team adopted the alternative scoring structure documented in the referenced evaluation reports—the PAI-1A score[166]—to replace the legacy PAI-1 score.

Recognizing the varying degrees of site complexity and the underlying decision processes, the CPUC framework includes three levels of detail, all built around the same core questions but incorporating additional sources and higher levels of review as the size and complexity of projects increase. Table B-12 presents the potential data sources for each of the three levels of NTG analysis.[167]

Table B-12. NTG Rigor and Data Sources

NTG Rigor	Program Files [a]	Decision-Maker Survey	Vendor/Dealer Survey	Secondary Research Findings
Basic NTG	●	●	●	
Standard NTG	●	●	●	
Standard NTG – Very Large	●	●	●	●

[a] Program files for MDHD make-ready projects can contain data on equipment costs, expected savings, funding sources and amounts, and decision-maker and vendor contact information.

Decision-maker (fleet manager) surveys are a key source of attribution data under all three levels of NTG rigor. The Team used three separate sets of questions to assess three components of the core NTG ratio, placing each score on a 0.0–1.0 scale as an alternate way to characterize Utility program influence.

- PAI-1A score captures the type of transportation electrification investment participating fleet managers would most likely have procured if the Utility program had not been available, yielding a score between 0.0 and 1.0.
- PAI-2 score reflects the extent to which participating fleet managers perceived the Utility program (rebates, recommendation, training, or other program intervention) as important relative to non-program factors in their decisions to implement the transportation electrification projects they eventually completed. The Team determined this score by asking fleet managers to assign importance values (using a 0–10 scale) to both the program and the most important non-program influences, so that the two values totaled 10, and then dividing the Utility program's score by 10. We halved the score for fleet managers who said they had already made their

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165 Quantum Energy Analytics and DNV-GL. March 26, 2021. Final Impact Evaluation: NonResidential Lighting Sector Program Year 2019. Appendix A. Prepared for California Public Utilities Commission. www.calmac.org/publications/PY2019_NonresLgtImpact_FinalRpt.pdf
Itron, ERS, and Tierra Resource Consultants. March 31, 2020. PY2018 Small/Medium Commercial (SMB) Sector ESPI Impact Evaluation: Final Report. Prepared for California Public Utilities Commission. pda.energydataweb.com/api/view/2361/2018_Small Medium Com ESPI_Evaluation_Final_with_Appendices.pdf

166 PAI-1A is the PAI-1 alternative.

167 Participant fleet manager surveys were the primary source of the self-report NTG ratio in EY2025. When information from other data sources was available, the Evaluation Team incorporated these data to determine a site's NTG ratio.

decision to procure the specific program-qualifying transportation electrification project before they learned about the program.

- PAI-3 score captures the likelihood (on a 0–10 scale, where 0 is *not at all likely* and 10 is *extremely likely*) that fleet managers would have implemented the same transportation electrification project (or might implement a similar project in the future) in the absence of the Utility program (the counterfactual). The Team calculated the project's score by subtracting from 10 the likelihood rating of procuring the exact same program-qualifying transportation electrification project and then dividing by 10 (yielding a score between 0.0 and 1.0).

Core NTG Ratio Scoring

The Team calculated the self-report core NTG ratio for a project, prior to accounting for participant spillover, as the average of the PAI-1A, PAI-2, and PAI-3 values. The freeridership ratio for a project was equal to one minus the self-report core NTG value.

Participant Spillover Calculation

To measure participant spillover, the Evaluation Team asked fleet managers if they had chosen to electrify more of their fleet without additional incentives from the MDHD Utility fleet electrification program as a result of their earlier participation in the MDHD program. We then asked follow-up questions about the type and number of EVs that fleet managers had purchased without support from the MDHD Utility fleet electrification program and whether they had received financial support from any other organization for these purchases. If they had received support, we asked what specific organizations had provided that financial support and what amount of financial support fleet managers had received. An electrification project does not qualify as participant spillover attributable to the MDHD program if a participating fleet manager received financial support from another organization for the additional fleet electrification activity.

The Evaluation Team asked participating fleet managers how important their participation in the MDHD Utility fleet electrification program was to their decision to electrify more of their fleet without MDHD program support. A participant spillover electrification project is one for which the fleet manager rated the importance of their MDHD program participation as 8, 9, or 10 on a 10-point scale, where 0 meant *not at all important* and 10 meant *extremely important*. An electrification project that received a rating of 8, 9, or 10 and did not receive financial support from another organization was eligible to have the full amount of estimated spillover benefits attributed to the MDHD Utility program.

The Team assigned benefits values to spillover projects based on evaluated gross program benefits. A participating fleet manager's project participant spillover ratio equals the sum of fleet manager-reported additional spillover benefits, divided by the total gross program benefits achieved by the MDHD project:

$$Participant\ Spillover\ Ratio = \frac{\sum Spillover\ Benefits\ Reported\ by\ Fleet\ Manager}{\sum MDHD\ Program\ Benefits\ Reported\ by\ Fleet\ Manager}$$

Final Self-Report NTG Ratio

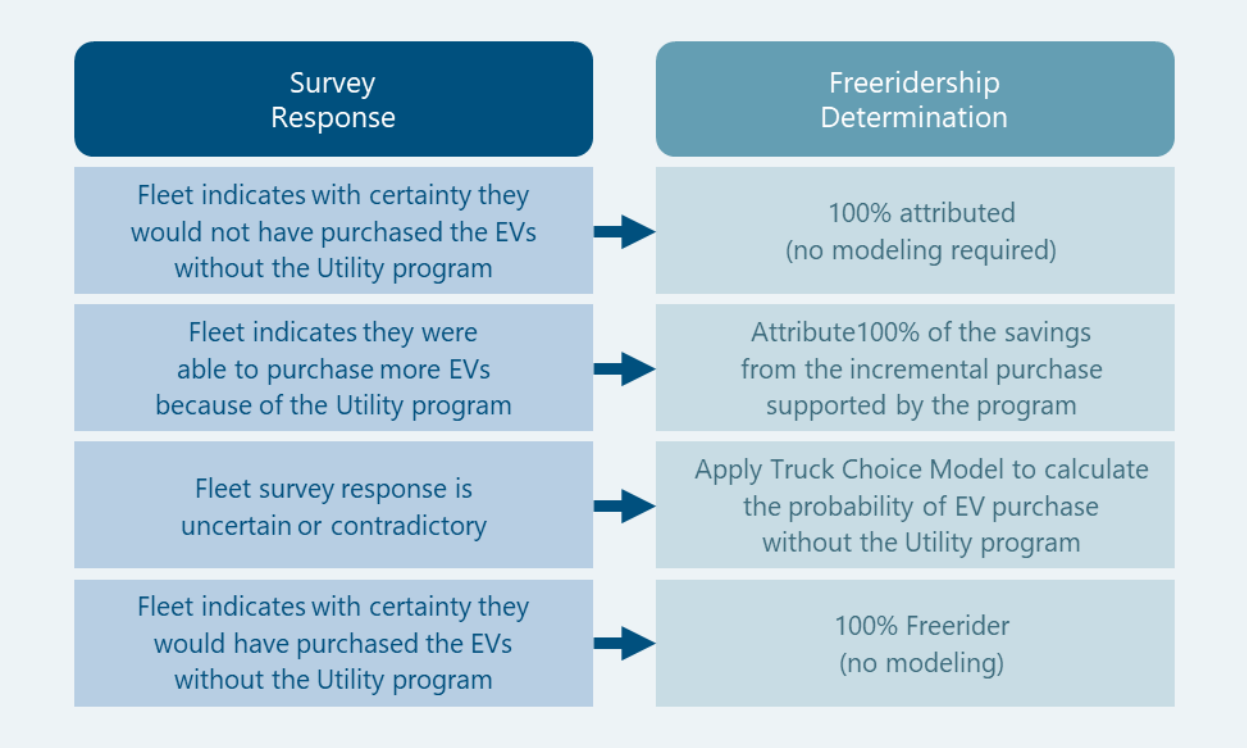
The Team separately estimated freeridership and spillover rates for each surveyed project to determine the final project-specific self-report NTG ratios using the following calculation:

$$NTG\ Ratio\ =\ 1\ -\ Freeridership\ Ratio\ +\ Participant\ Spillover\ Ratio$$

Self-Report NTG Integration with TCM to Determine Final NTG Ratio

The Evaluation Team determined the final NTG ratio for a MDHD project by applying the self-report NTG ratio or by applying the UC Davis TCM. Figure B-4 describes the situations in which we used the self-report NTG ratio.

Figure B-4. Freeridership Determination for MDHD Projects



Truck Choice Model

The TCM provides a supplementary method for estimating participant impacts (Area 4 in Figure B-4) from the Utility programs relative to the natural baseline and is one of the only simulations we run in the Evaluation. The tool provides insights into "what if" questions, such as, "What if the BTM incentive only covered 50% of the costs?" The Evaluation Team developed a version of the TCM with a focus on the market sectors most heavily represented in the Utilities' programs and varied key inputs to understand their sensitivity on EV adoption, all else equal.

Surveys

The Evaluation Team used survey data regarding fleets' motivations for participating in Utility electrification programs and experience with the process, barriers to electrification, costs and benefits of program participation, and operational constraints.

To gather the survey data, the Evaluation Team invited respondents to complete surveys via email. We designed the survey questions to align with the evaluation objectives and focused the questions on understanding fleets' experience with the program.

Forty-two fleet managers responded to the fleet manager survey in EY2025. The Evaluation Team compiled survey data to produce and interpret graphical analysis of the survey responses.

The Evaluation Team analyzed the fleet manager survey primarily at the Utility stratum. For select questions, we further stratified the sample by vehicle type and other variables when sample size allowed to provide additional insights. The Team created graphical data representations to interpret survey data and draw conclusions about and identify trends in fleets' experiences with electrification. Due to the small sample sizes, the Evaluation Team did not apply any significance testing to EY2025 survey data.

Interviews

The Team conducted in-depth interviews with the four participating Utilities to gather qualitative insights about each Utility's experience with the program process, barriers to electrification, program design, costs and benefits, and operational constraints. We used this interview data to provide context to information from other sources, such as PAC presentations.

The Team synthesized Utilities' responses to in-depth interview questions to draw conclusions about the topics covered in the interview. We used a mostly consistent set of questions across Utilities and also analyzed responses from each Utility separately.

The Evaluation Team conducted interviews with 10 withdrawn fleet managers to understand their reasons for withdrawing from the MDHD program, satisfaction with their program interactions, barriers to electrification, and actions taken outside of the program. In evaluation years EY2023 and before, the Evaluation Team gathered information from withdrawn fleet managers using surveys; however, due to the small population, we determined that interviews would yield better quality data. Starting in EY2024, the Evaluation Team conducted interviews for withdrawn fleet managers. The Team synthesized EY2025 interview results to identify key themes and draw conclusions. As with the utility interviews, we analyzed each respondent's feedback separately but used a consistent set of questions for each interview.

Public Charging (Schools, Parks, and EV Fast Charge) Evaluation Methodology

This section outlines the data collection and analysis for the Public Charging program evaluation.

Data Collection Methodology

The following subsections discuss data collection for the Public Charging program evaluation, including program data, materials, AMI and EVSE data, site visits, and Utility interviews.

Program Performance Metrics

Program data provides essential insights into program performance. The Evaluation Team collected and securely transferred Utility data between Microsoft Azure cloud-based environments and a secure SharePoint site. The Team sought to transfer data monthly, with some variation in timing among PG&E, SCE, and SDG&E.[168] Once we received data from these Utilities, we moved it to the Cadmus data warehouse for secure storage, retrieval, and analysis. The Evaluation Team then unified the data from each Utility to provide a single resource output to adhere to SB 350 reporting.

The data collected included program application status and timing as well as detailed information such as the number of ports by type/level, site status by program and by DAC, application phase timing, and number of applications that were operational and had been activated.

Program Materials

The Evaluation Team reviewed available EY2025 program-related material such as marketing education and outreach documentation, Advice Letters, and PAC presentations. The annual program material review is important to maintain an understanding of each program, including program changes and implementation progress.

Table B-13 shows a list of the material types the Evaluation Team reviewed by Utility in EY2025.

Table B-13. Public Charging Materials Reviewed

Utility	Program Materials Provided
Liberty	No new materials for EY2025
PG&E	• (Schools and Parks Pilots and EV Fast Charge) PAC presentations • (Schools and Parks Pilots and EV Fast Charge) Regulatory documents (Advice Letters)
SCE	• PAC presentations
SDG&E	• Marketing materials

[168] Liberty did not provide site data for EY2025 because the Utility did not complete any public charging sites.

AMI/EVSP

The Evaluation Team used AMI data to estimate charger usage, which is a key input for estimating program impacts such as impacts to the grid, displaced petroleum, emissions reduced by EV adoption, and associated health impacts. The Team collected and securely transferred AMI data between the Utilities and Microsoft Azure cloud-based environments, used Azure Databricks to transform and standardize the data, and imported the standardized data into an SQL server data warehouse. We performed these transfers monthly, with some variation in timing among the Utilities. Once we received the data, we input it into our data warehouse for secure storage and retrieval and aggregated it for subsequent calculations and analysis. Time-stamped energy consumption data were in 15-minute intervals.

A second critical data source was EVSE data provided by participating EVSPs. The Utilities developed a process for screening and approving EVSPs based in part on their ability to provide essential monthly charging and interval data from EVSE sessions by station and by port.

Together, AMI and EVSE data provide the basis for analyzing program performance at a granular level. The Team used data from EVSPs to examine port utilization, which is based on the time a vehicle is parked at a charger and consuming energy.

The Evaluation Team worked to acquire complete AMI and EVSE data for every charging session from the Utilities and EVSPs. When AMI data was not available from the Utility, the Team worked with the Utility to either obtain the data to incorporate into future analyses, used a customer sub-metered data set provided by the Utility, or synthesized data from existing EVSE data.

Synthesized Data

For sites with no AMI data or data missing for some periods of time, the Evaluation Team generated representative AMI data based on available EVSP data using a conversion factor specific to each site of the ratio between EVSP data and AMI data. We derived conversion factors by evaluating the ratio of total kilowatt-hours delivered as reported by EVSPs, which in most cases existed at the same site for a different time period or for similar EVSE and vehicles. For the rare case with no specific match, the Team used a standard factor of 0.85 to account for electricity losses between the meter and the EVSE.

Annualized Data

The Evaluation Team considered all operational sites for annualization.[169] In the EY2021 annual evaluation, we annualized all sites with greater than six months of usage data and considered annualizing sites with between three and six months of usage data depending on observed usage patterns. For EY2022 to EY2025, the Evaluation Team annualized all sites to provide a complete picture of the entire program to date and the impacts of the program performance over a full 10-year life. In general, sites with a period of performance of less than six months will inherently have lower utilization than fully developed sites. As a

[169] The Evaluation Team annualized electricity usage data by extrapolating partial year site electricity usage to a full year for sites with operational AMI data (data indicating that EVs were actively being charged). Annualizing the data allowed the Team to make site-to-site and year-over-year comparisons.

result, annualized sites that have been operational for six months or less will underrepresent the full 10-year impact; however, excluding those sites would create an even greater underrepresentation.

The Team annualized site data by creating a representative 12-month operation period, which could be projected into the future to the point when the site will reach its 10-year life. We calculated the 10-year life by determining when the operational use of the EVSE would begin and projecting forward 10 years from that date. For sites with more than 12 months of fully developed utilization, the Team used the most recent 12 months. For sites with less than 12 months of fully developed utilization, we removed the months of data before the date the site reached 75% of its maximum monthly use and replaced that data with a synthesis of all months of data following 75% of the maximum utilization.

Site Visits

Site visits to program charging stations are an important data collection activity, as they provide an on-the-ground view of installed sites. For EY2025, the Public Charging site visits brought supplemental qualitative insights, especially regarding lessons learned (such as why some sites may have higher usage than others). The Team attempted a census of visits to activated sites for EY2025.

Site Costs

The Evaluation Team collected site-level costs from the Utilities via their annual SB 350 report. These costs include TTM and for Utility-owned infrastructure, BTM costs.

Interviews

In-depth interviews provide critical insight on the original intent, actual implementation, and level of success of the Pilots and programs and allow us to assess their potential to scale up. For EY2025, we conducted close-out phone interviews with core staff overseeing the public charging programs across the four Utilities.[170] We developed interview guides outlining key topic areas and questions for discussion to ensure that we covered each topic area during the interview. Topics included staff roles and responsibilities, program design and implementation, and areas of challenge and success.

Analysis Methodology

This section provides an overview of the Evaluation Team's analyses of the Public Charging bundle. This included estimating EV adoption and grid impacts; developing the vehicle counterfactual; determining petroleum displacement, GHG and criteria pollutant emissions reductions, and health impacts; preparing for a TCO analysis, qualitative site visits, and Utility interview analysis, and using these analyses to assess impacts on DACs versus non-DACs.

[170] This pertained specifically to the Schools Pilots, Parks Pilots, and PG&E EV Fast Charge program.

EV Adoption

The Team conducted an EV adoption analysis to estimate the effects of utility investments in public charging infrastructure on household ownership of EVs.[171] Recent research shows that increased availability of public charging networks can boost EV purchases.[172] However, the mechanism by which public charging availability affects EV purchases is not clear. Understanding this process may help the Utilities and other investors in public EV charging facilities make more-productive investments. This section describes the Evaluation Team's approach, and the data sources used to estimate the impact of public charging programs on EV adoption.

The Team estimated the effect of public charging stations on EV adoption for populations neighboring public charging stations using a two-stage analysis of the following topics.[173]

- Historical impacts of public EV charging on vehicle ownership
- Ownership attributable to specific utility investments in public charging

In the first stage, the Team estimated the effects of access to any neighboring public charging on EV ownership.[174] The second stage involved an attribution analysis: the Team applied the regression coefficient estimates of public charging access from the first stage to the specific utility public charging investments to estimate their impact on EV ownership (for the EV Fast Charge program, Schools Pilot, and Parks Pilot).

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171 PG&E made these investments through Utility EV pilots and programs including the PG&E EV Fast Charge program and Schools and Parks Pilots.

172 Springel, Katalin. 2021. "Network Externality and Subsidy Structure in Two-Sided Markets: Evidence from Electric Vehicle Incentives." American Economic Journal: Economic Policy, 13 (4): 393–432.

173 There are two main channels through which the availability of public charging networks may affect EV purchases. The first is a network effect, through which EV owners gain increased access to the public charging stations because of the stations' placement at destinations such as workplaces, commercial establishments, schools, and parks. The Evaluation Team expects the availability of EV charging equipment at convenient locations (for midday charging away from home) to increase the convenience of owning an EV (such as by lessening range anxiety) and to increase the probability of EV ownership. The second channel is a neighborhood effect on the driving population living in areas neighboring the public EV charging stations. The Evaluation Team expects the availability of nearby charging infrastructure to reduce the cost of EV ownership by providing alternatives to home charging. We expect that public EV charging will have the biggest impact on residents of multifamily buildings, many of whom will have limited access to EV charging equipment, or on low-income households, who may be unable to afford home EV charging equipment. The public charging access may boost EV ownership through both channels, and there may be positive interactive effects between the channels that boost the overall impact of public charging networks. The Evaluation Team focused on analyzing the second channel and will analyze the impacts for the first channel separately when data become available.

174 For the stage one analysis, the Evaluation Team focused on general public charging, not Utility-specific charging; however, for the stage two analysis, we will consider both Utility- and program-specific charging.

The Utility EV Adoption findings sections provide the end results as the estimated changes in annual EV ownership (EV registration), which are a function of changes in annual access to public EV charging stations, while accounting for potential nonrandom siting of public EV charging infrastructure.

Analysis Data and Sample Selection

The Evaluation Team assembled a CBG panel dataset on annual EV ownership and access to public EV charging for calendar years 2015 through 2023 to perform the EV adoption analysis.[175] The Team assembled the panel data from free, publicly available secondary data sources on EV registrations, public EV charging infrastructure, census demographic data, and census geography (CBG and census block) shape files. Table B-14 lists the data sources for the CBG panel.

[175] The most recent CBG-level vehicle registration data available at the time the Evaluation Team assembled the panel dataset had been updated in 2023.

Table B-14. EV Adoption Data Collection

Data Element	Description	Source	Reporting Unit
California CBG shapefiles	Polygon shapefile representing CBGs for the state of California from 2010 Census	U.S. Census Bureau: www.census.gov/cgi-bin/geo/shapefiles/index.php?year=2010&layergroup=Block+Groups	CBG
California census block shapefiles	Polygon shapefile representing census blocks for the state of California from the 2010 Census	U.S. Census Bureau: www.census.gov/geographies/mapping-files/time-series/geo/tiger-line-file.2010.html	Census block
California vehicle registration data	Data on EV ownership for California CBGs by vehicle category, fuel type, fuel technology, and number of vehicles registered at the same address for 2015 through 2023	CARB: arb.ca.gov/emfac/fleet-db	CBG
EV charging stations	EV station attributes and location	National Renewable Energy Laboratory AFDC: developer.nrel.gov/docs/transportation/alt-fuel-stations-v1/	Fueling station
Population demographics and socioeconomic data	Decennial Census or ACS data (five years) on population, housing, income, race, and ethnicity	U.S. Census Bureau: data.census.gov/cedsci/	Zip code tabulation area, census block, or CBG
California DACs	Data on CalEnviroScreen 4.0 scores in census tracts that the Team could use to identify DACs	California EPA Office of Environmental Health Hazard Assessment: oehha.ca.gov/calenviroscreen/maps-data	Census track
California cities land zoning shapefiles	Polygon shapefile representing land use for the top 20 largest cities in California where land zoning data are publicly available	Anaheim: main-anaheim.opendata.arcgis.com/datasets/f40f6f69179a4bccb5d4359a0e054b04_3/about Bakersfield: bakersfielddatalibrary-cob.opendata.arcgis.com/ Fresno: www.co.fresno.ca.us/departments/public-works-planning/divisions-of-public-works-and-planning/cds/gis-shapefiles Long Beach: datalb.longbeach.gov/search?q=zoning Los Angeles: geohub.lacity.org/datasets/lahub::zoning/about Oakland: data.oaklandca.gov/dataset/Zoning/q8sz-29u5 Sacramento: data.cityofsacramento.org/search?q=zoning San Diego: data.sandiego.gov/datasets/zoning/ San Francisco: data.sfgov.org/Geographic-Locations-and-Boundaries/Zoning-Map-Zoning-Districts/3i4a-hu95	Land zone

Data Element	Description	Source	Reporting Unit
		San Jose: gisdata-csj.opendata.arcgis.com/datasets/CSJ::zoning-districts/about Santa Ana: gis-santa-ana.opendata.arcgis.com/datasets/Santa-Ana::zoning-classifications/explore?location=33.737642%2C-117.887350%2C13.14 Riverside: geodata-cityofriverside.opendata.arcgis.com/datasets/edd9eb97a1dd446cb30336d91bc40e8a_2/explore?location=33.945918%2C-117.401342%2C12.00 Stockton: www.stocktongov.com/services/gis/mapdatdat.html Chula Vista: chulavista-cvgis.opendata.arcgis.com/datasets/a0591cdb609548a182f35bd70a431a20/explore?location=32.631384%2C-117.021350%2C12.73 Fremont: fremont-ca-open-data-cofgis.hub.arcgis.com/datasets/25db2e74c6254091a6f340cf01f8f092_0/explore?location=37.529560%2C-122.012239%2C12.00 Fontana: data-fontanaca.opendata.arcgis.com/datasets/FontanaCA::zoning-2/explore?location=34.104611%2C-117.459495%2C11.66&showTable=true Oxnard: data-oxnard.opendata.arcgis.com/datasets/Oxnard::zoning/explore?location=34.173578%2C-119.184614%2C13.63 Rancho Cucamonga: rcdata-regis.opendata.arcgis.com/datasets/zoning/explore?location=34.106902%2C-117.563238%2C15.16&showTable=true Elk Grove: gisdata.elkgrovecity.org/datasets/elkmap::city-of-elk-grove-zoning/explore?location=38.407478%2C-121.378550%2C12.52 Garden Grove: ggcity.org/maps/data-portal/#/osm/planning/zoning	
California utility investments in EV charging stations	EV station attributes and location	California Utilities	Fuel station

The Evaluation Team reviewed all data for completeness and accuracy and documented any significant gaps or other issues that might affect the analysis results.

Our analysis sample includes all California CBGs, except those meeting one or more exclusion criteria:

- The CBG was in a rural area.[176]
- The CBG did not have any households.
- The CBG was new (since the 2010 census).
- The CBG has outlier EV registration numbers (greater than the 99th percentile in EY2023).

After the Team applied these sample exclusion criteria, 17,940 CBGs remained in the analysis sample.

Modeling of EV Ownership

The goal of the stage one analysis was to estimate the impact of public EV charging access on EV ownership. During this stage, we constructed a composite measure of CBG access to public charging as a function of the number of neighboring public EV charging stations, the geographical distance from homes to the stations, and the number of chargers (ports) at each station. Next, we performed the EV adoption analysis using annual panel data on California EV registrations at the most granular spatial resolution possible (the CBG level) from 2015 through 2023. We then used two approaches to estimate the impacts of public charging on EV ownership.

We first conducted an OLS estimation of a panel annual regression or long differences regression of normalized EV registrations (annual registrations per 1,000 households), which assumes that the siting of public charging infrastructure was exogenous to EV registrations. The panel model included year-fixed effects, CBG-fixed effects, and county time trends. The Team used CBG-fixed effects and county time trends to control for, respectively, time-invariant CBG and time-varying county characteristics that could correlate with the location decisions of public charging and subsequent EV adoption. The long differences model of the change in annual EV registrations between 2015 and 2023 includes controls for income, building type, and annual EV registrations in 2015.

The Evaluation Team recognized the potential for bias in the estimates from this OLS analysis if public EV charging location decisions drew from unobservable trends in EV registrations, such as locating public charging infrastructure in areas with higher EV demand (we refer to this as the endogeneity of charging location decisions). Thus, the Evaluation Team also estimated the public EV charging impacts using IV-2SLS models. These models use the percentage of the neighboring land area zoned for public EV charging

[176] We adopted the U.S. Census Bureau's urban-rural classification, which is based on 2010 Census population and housing unit: www.census.gov/programs-surveys/geography/guidance/geo-areas/urban-rural.html. Previous literature has indicated that the inclusion of rural areas could lead to overestimating the effect of chargers on these non-urban residents and that limiting the study to an urban population could reduce variation in population density. See Hsu, Chih-Wei, and Kevin Fingerman. 2021. "Public Electric Vehicle Charger Access Disparities across Race and Income in California." Transport Policy (100): 59–67.

facilities as the instrumental variable while controlling for income and percentage of multifamily housing units in CBGs.[177]

In stage two, the Team took a three-step approach to estimate the impact of California utility investments in public charging on EV adoption in the study period:[178]

- **Step 1:** Using the framework above, we estimated the effect of the Utility charging stations on public charging access for California households. We calculated the change in access for each CBG.[179]
- **Step 2:** We used the regression model estimates to determine the impact on EV ownership of the change in public charging access for households in each affected CBG.
- **Step 3:** We summed the changes in ownership across CBGs to determine the total impact on EV adoption and to estimate the standard error.

A notable benefit of this two-stage approach to assessing EV and EVSE market acceleration is that it can apply to evaluations of other programs that also increase EV charging access, which ensures methodological consistency.

Grid Impacts

The Evaluation Team calculated the associated grid impacts for the Public Charging programs based on the consumed energy from charging stations installed through the programs and charging session data from the EVSPs. As part of this analysis, the Team examined impacts at the program and bundle levels. This section describes the approach, data sources, and analyses we performed to estimate Public Charging grid impacts.

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[177] A valid instrumental variable will be strongly correlated with the location of public charging but uncorrelated with EV adoption conditional on other exogenous explanatory variables. Our approach uses the availability of nearby land zoned for public charging as a source of exogenous variation in the availability of public charging among CBGs with similar income levels and housing types. Specifically, the analysis uses the percentage of CBG land area zoned for commercial use, public use (such as schools or government buildings), or parks and beaches. As public charging infrastructure may exist only on suitably zoned land, and land zoning remains mostly unchanged over time, proximity to space zoned for commercial, public uses, or parking should correlate with the change in access to public charging between 2015 and 2020 but not correlate with EV adoption over this period.

[178] The Team developed the current methodology to study the impact of public EV charging on existing EV adoption. Forecasting the impact in a future period will require a separate approach and additional data on the Utility investments in public charging.

[179] A full accounting of the impact of Utility investments would require considering whether EV charging station developers would build more (or fewer) charging stations if the Utilities had not built charging stations. Incorporating this supply response would diminish (or increase) the effect of the Utility charging network on EV adoption.

The Team collected, cleaned, and analyzed Utility AMI data, provided at 15-minute increments, to calculate total kilowatt-hour usage, on-peak and off-peak usage, and maximum demand, which were then used to calculate load factors. The Team took a three-step approach to this analysis:

- **Step 1:** Accounted for total consumption (kilowatt-hours), the proportion of consumption during the on-peak time period, and new load on the grid (kilowatts).
- **Step 2:** Targeted issues such as stability versus growth of charging load, charging load by time of day, and charging session flexibility.
- **Step 3:** Projected the extent to which transportation energy use can be integrated with the grid at a least cost to retail consumers and ratepayers.

We report these data by site, in aggregate, and on a daily and monthly basis.[180]

The Team used the essential primary and secondary data summarized in Table B-15 for the Public Charging grid impacts analysis.

Table B-15. Public Charging Grid Impacts Data Inputs

Category	Source
Primary Data	Utility AMI data, historical CAISO data (demand, supply sources, renewable curtailments), charging session data from EVSP networks
Secondary Data	Time varying Utility rates in effect at sites, EVSE (interval and charging session) data, site management details (charger capacities), site visits

The Evaluation Team uploaded AMI and EVSP data to the data warehouse and calculated results using the internal Power BI dashboard. Foundational program analysis included total electricity consumption (kilowatt-hours), and new demand (kilowatts) added to the grid. The Team established trends based on the proportion of electricity usage during the highest cost period (4 p.m. to 9 p.m. daily) versus other periods. We calculated load factors based on usage and utilization rates, which we based on the installed capacity for each site.

We performed analysis to determine how quickly sites are adopted by local users to calculate growth rates. We looked for trends during weekdays, evenings, and weekends and analyzed how this may impact utilization rates. The Team tracked consumer pricing when possible, to analyze site rate structures (flat rates or TOU rates) and price ranges. We investigated overall charging session trends and super-user trends to understand baseline utilization and identify lessons to incorporate into future public EV charging programs.

The use of 24-hour load curves provided key insights into how the grid is impacted by the program. Charging approaches in which EVs consume power during off-peak periods such as when solar output is high (midday) and/or demand is low (night) will become increasingly important as more EV loads are added to the grid and have a different role in each public charging program. Charging flexibility in

[180] The actual reported results for each Utility are presented in a way that masks personally identifiable information.

response to price signals offers a potentially valuable tool to safeguard the grid with new EV loads coming online and to support the growth of renewable energy.

The Evaluation Team applied the grid impact analysis to the actual AMI data for activated sites in EY2025 and annualized AMI data to support analyses with forecasts such as petroleum displacement and GHG and criteria pollutant emissions reductions. Through the annualization of AMI data, the Team identified the region of stable operation and leveraged this data to generate a statistically representative full year of operation.

Emissions calculations require matching the date and time of AMI data with the electric generation mix at the time of use. This approach necessitates normalizing emissions calculations across a full year to capture daily, monthly, and seasonal variations in electric generation mix. Therefore, we did not annualize data from sites with two months or less of data (as we were unable to determine seasonal variability). For sites with more than two but less than four months of data, we visually inspected the datasets and used expert judgement to evaluate whether the operation was consistent enough to be annualized.

Of the activated Public Charging sites in EY2025, the Evaluation Team annualized AMI data through a four-step process:

- **Step 1:** Find the maximum monthly site usage. The Team identified the month with the maximum total usage in kilowatt-hours for the site by examining the EY2025 AMI data.
- **Step 2:** Identify the start month. The starting month for the actual data used to develop the annualized data was the first month in which total usage exceeded 75% of the maximum month's usage.
- **Step 3:** Create a representative weekly load curve. Using the AMI data from the start month to the end of the year, we created an average daily load curve for each day of the week and for each 15-minute interval throughout the day.
- **Step 4:** Extrapolate a weekly load curve. Using the representative weekly load curve, we extrapolated AMI data that was outside the operational period. We then matched weekday load curves for each day of the week (such as matching Monday to Monday).

Counterfactual Development

The Team conducted secondary research to inform the development of the electric LDV and conventional counterfactual for the public charging sites: These counterfactuals are foundational to the public charging evaluation and impact the EV adoption analysis as well as analyses of petroleum displacement, GHG and criteria pollutant emissions reductions, and grid impacts. The subsections below describe the approach, data sources, and analyses performed to develop the counterfactuals for Public Charging.

The Evaluation Team calculated the electric LDV counterfactual for EY2025 as average EV efficiency (kilowatt-hours per mile) using a weighted average for the most popular new EVs in each Utility territory. Next, the Team calculated the conventional LDV counterfactual for EY2025 as the average fuel economy (miles per gallon) for a representative LDV on the road that the electric LDV counterfactual replaces based on the comparable mix to the EVs available—currently this mix is sedans along with small and mid-size SUVs (some Rivian and Ford light-duty trucks have reached the market, but these currently represent less

than 2% of the total EVs on the road), but that mix is expected to change over time. We determined that the counterfactual is a composite of all equivalent new vehicles that could have been purchased instead of an EV over the past five years.

The Evaluation Team used the secondary data presented in Table B-16 to develop the electric and conventional LDV counterfactuals.

Table B-16. Counterfactual Data Inputs by Category

Category	Data Inputs
Electric LDV Counterfactual	New EV sales by county: www.energy.ca.gov/files/zev-and-infrastructure-stats-data
	EV efficiency: www.fueleconomy.gov
Conventional LDV Counterfactual	BEV and PHEV registrations by county: www.energy.ca.gov/files/zev-and-infrastructure-stats-data
	Popular counterfactual vehicles sold and percentage of their sales: www.cncda.org/news/?category=auto-outlook
	Fuel economy: www.fueleconomy.gov

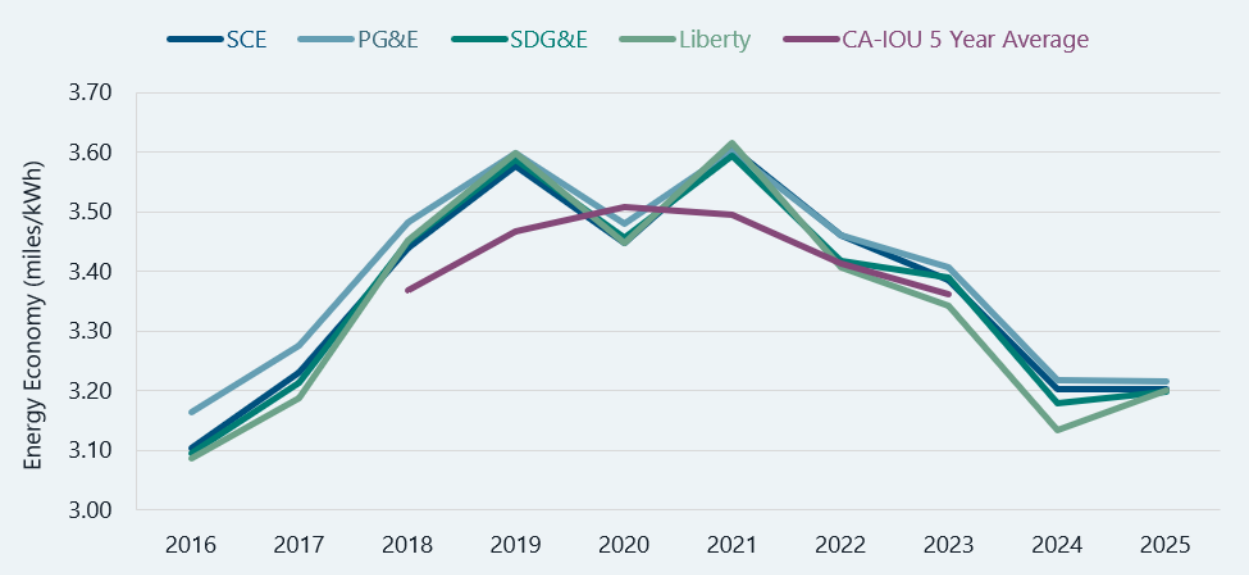
The counterfactual results from 2016 through 2025 are shown in Table B-17.

Table B-17. Electrical Vehicle Efficiency by Year and Utility

Year	Liberty	PG&E	SCE	SDG&E	California Utility Average (kWh/mile)	Largest Difference	California Utility 5-Year Average (kWh/mile)	5-Year Efficiency (kWh/mile) Average
2016	3.09	3.17	3.10	3.09	3.11	2.6%	-	-
2017	3.19	3.28	3.23	3.21	3.23	2.8%	-	-
2018	3.45	3.48	3.44	3.45	3.46	1.3%	-	-
2019	3.60	3.60	3.58	3.59	3.59	0.7%	-	-
2020	3.45	3.48	3.45	3.46	3.46	0.9%	3.37	0.297
2021	3.63	3.62	3.62	3.61	3.62	0.5%	3.47	0.288
2022	3.43	3.48	3.48	3.45	3.46	1.6%	3.52	0.284
2023	3.34	3.41	3.39	3.39	3.38	1.9%	3.49	0.296
2024	3.14	3.22	3.20	3.18	3.20	2.7%	3.41	0.314
2025	3.20	3.22	3.20	3.20	3.20	0.6%	3.36	0.312

The Team used the most recent five-year average (accounting for the most likely mix of EVs using these stations) for all participating Utilities because the difference between Utilities (due to different mixes of EVs) is not significant, as shown in Figure B-5.

Figure B-5. EV Efficiency Per Utility Per Year



The Team then identified the comparable vehicle type mix, shown in Figure B-6, which allowed the Team to create California-wide counterfactual weighted averages for 2017 through 2025, as well as the prior five-year averages for years with five prior years of data (as shown in Figure B-6 and Table B-18).

Figure B-6. EV Market Share Penetration Rates to Reach 100% BEV Sales by 2035

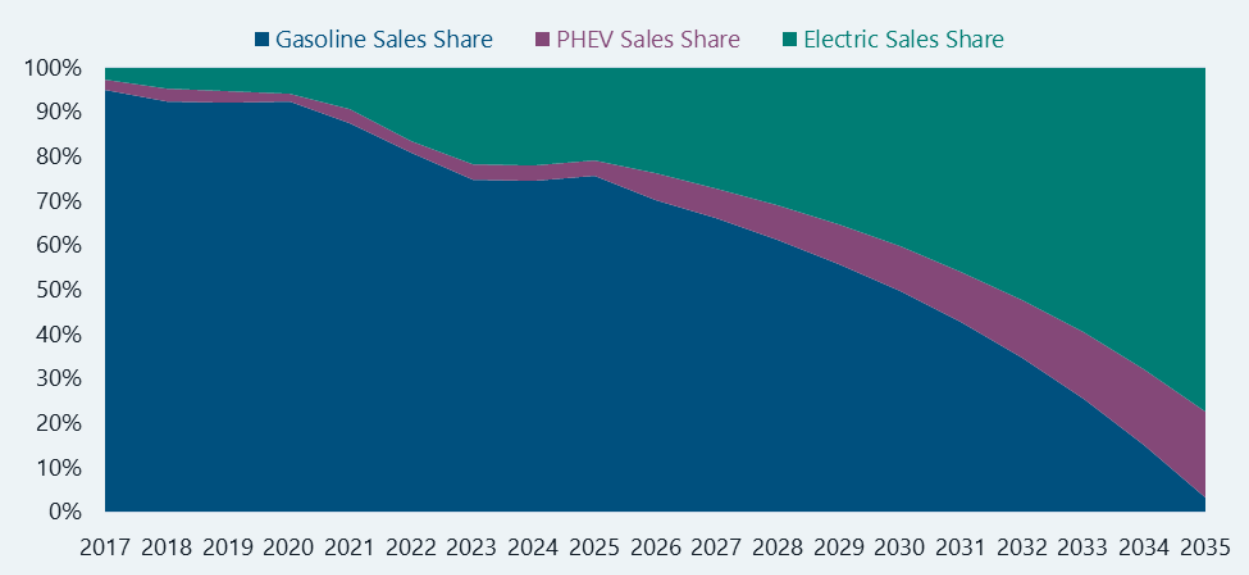


Table B-18. Counterfactual Vehicle Fuel Economy by Year

Year	Gasoline	PHEV	Electric	Weighted Average	Last 5-Year Average
2017	27.00	71.83	109.38	30.21	-
2018	27.06	72.98	111.82	32.33	-
2019	26.90	72.69	117.07	32.64	-
2020	27.46	70.65	115.95	33.76	-
2021	28.13	63.06	121.75	38.18	33.43
2022	28.36	57.39	119.59	44.29	36.13
2023	29.75	52.38	117.39	49.54	39.57
2024	30.60	54.42	109.03	48.69	42.75
2025	29.16	44.47	108.01	46.17	45.31

Petroleum Displacement

One goal of the Public Charging programs is to reduce the amount of petroleum fuel used as conventional vehicles are replaced by EVs. As part of this analysis, the Team examined petroleum fuel reduction at the program and bundle levels. This section describes the approach, data sources, and analyses we performed to estimate the Public Charging–related petroleum fuel reduction.

The Team determined the reduction in gasoline equivalent gallons of petroleum compared with electric usage as a result of the Public Charging programs. To complete this analysis, we calculated annual energy consumption, EV annual miles traveled, and annual counterfactual vehicle fuel consumption, as described in the *Counterfactual Development* section above.

The Team developed a petroleum displacement tool to estimate EV miles traveled by converting electrical energy use from the EV Public Charging programs in kilowatt-hours from Utility AMI data to petroleum displaced by the use of electricity. We assumed that conventional vehicles would have been driven the same number of miles in absence of the program (the counterfactual). We then calculated the petroleum displacement in terms of the gasoline gallons equivalency using the petroleum displacement equation shown in Equation 2:

Equation 2. Petroleum Displacement Calculation

$$Gallons\_Displaced_{x,y} = \frac{Annual\ kWh_{x,y} * (1 - Charger\_Losses) * Counterfactual\_Efficency_z}{EV\_Efficiency_{x,y}}$$

The Team used the primary and secondary data presented in Table B-19 for the Public Charging petroleum analysis.

Table B-19. Public Charging Petroleum Displacement Data Inputs

Category	Source
Primary (critical) Data	Utility AMI data, EMFAC database, and counterfactual tables to assign linkages between sites and EMFAC Vehicle Classification Codes
Secondary Data	EVSE (interval and charging session) data

The Team conducted a range of categorical analyses (shown in Table B-20) using tools that include Azure Studio (SQL statements for the resulting calculations), the counterfactual lookup table (populated by the EMFAC and other sources), and outputs from analysis described above. As noted above, Utility AMI data were the basis for much of this analysis.

Table B-20. Analysis of Petroleum Displacement

Category	Analysis
Reference Counterfactuals and Secondary Data	For each vehicle type, referenced gallons per mile and kilowatt-hours per mile efficiency from the following sources: • Vehicle counterfactuals • Five-year weighted average based on California vehicle registrations from CEC[a] and individual vehicle DMV fuel economies for both EV and conventional vehicles from the EPA[b]
Determine EV Energy Consumption	Referenced annual kilowatt-hours consumed by EVSE at each site (as described in the *Grid Impacts* analysis)
Account for Charging Losses	Compared AMI data to EVSP session data
Calculate Vehicle Miles	Determined miles based on kilowatt-hours consumed using reference counterfactual
Estimate Petroleum Displacement	Estimated petroleum displacement based on conventional miles and fuel consumption factor of conventional vehicles

[a] California Energy Commission. 2024. "Light-Duty Vehicle Population in California." www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/light-duty-vehicle

[b] U.S. Department of Energy. 2024. "Fuel Economy." www.fueleconomy.gov/

GHG and Criteria Pollutant Impacts

This section describes the methods and sources for calculating GHG and criteria pollutant emissions reductions. The Public Charging programs are expected to reduce the amount of GHG and criteria pollutants emitted into the environment as EVs replace conventional ICE vehicles.

The Team calculated reduced emissions from displaced fossil fuel use as a result of ICE vehicles not in service because of the Public Charging programs. We first developed an ICE counterfactual, then calculated the emissions associated with these vehicles under conditions that otherwise matched the EVs to create a baseline.

The criteria pollutants emissions reduction calculations account for NO_X, $PM_{2.5}$ and PM_{10}, CO, and SO_X. The Evaluation Team also estimated emissions reductions of ROGs, which are not criteria pollutants.

Because the electric grid emissions profile varies substantially by time of day and season, the Evaluation Team estimated reductions using actual 8,760-hour load curves based on Utility meter data and calculated the annual avoided emissions for the gallons of fossil fuels that were displaced.

The total program and Pilot emissions impact for key pollutants presented in Table B-21 are net of annual emissions from the displaced counterfactual fossil fuel equipment and the electricity consumed annually by the adopted electric equipment. Local emissions reductions are presented for the remaining pollutants.

We developed GHG and criteria pollutants reduction estimates for the overall program, each Utility, and individual DACs.

Table B-21. GHG and Criteria Pollutant Data Inputs

Description	Unit	Source
Site-Level AMI Electric Data in 15-Minute Intervals	kWh	Utility AMI (~1 month delay between measurement and reporting)
Overall Electricity Demand by 5-Minute Interval	MWh	CAISO Demand (Real time)
CO_2 Grid Emission by 5-Minute Interval	MT	CAISO Emissions (Real time)
Resource Mix by Interval	% by generator fuel	CAISO Supply (Real time)
California Utility Integrated Resource Planning Clean Power System Tool	% by generator fuel	CPUC Developed Clean Power System Tool
Electricity Emission Factors by Resource (details below)	Lb/MWh [a]	EPA eGRID (2023)
NO_X Emissions Rate	grams/kWh	
SO_2 Emissions Rate	grams/kWh	
CO_2 Emissions Rate	kg/kWh	
CH_4 Emissions Rate	grams/kWh	
N_2O Emissions Rate	grams/kWh	
CO_2 Equivalent Emissions Rate	kg/kWh	
Vehicle Emissions (ROG, CO, NO_X, CO_2, PM_{10}, $PM_{2.5}$, SO_X) by Vehicle and Fuel	g/mi	CARB EMFAC (2021 v.1.0.2 model extracted February 2025)
Vehicle Type (Vehicle Classification Codes or linkage to emission tables)	Standard category	Petroleum reduction methodology
Petroleum Use by Month	Unit measure	Petroleum reduction methodology
Petroleum Fuel Type	name	Petroleum reduction methodology

[a] Units provided by eGRID are in pounds per megawatt-hour and converted to grams per kilowatt-hour (and kilograms per kilowatt-hour for CO_2) for the purposes of this work.

These are multiyear programs, and several input sources are updated periodically. The Team uses newly published resources as they become available.

The Team completed the analysis in four steps using the CAISO application programming interface, the CPUC IRP RESOLVE model, eGRID, and EMFAC:

- **Electricity emissions:** We used CAISO five-minute demand and resource mix data reported by zone to establish an emissions record for each pollutant. We averaged five-minute interval emissions data, applied this to each 15-minute AMI interval, and applied the CAISO-specific emissions factors for that resource provided by the eGRID dataset.
- **Counterfactual emissions:** The Team determined baseline emissions for counterfactual vehicles using EMFAC for specific displaced fuel use. We determined this value based on the application using a standard source for lower heating value energy content available within that fuel on a per unit energy (Btu) basis. This is most often measured in Btus per gallon to derive the grams per gallon and ultimately the tons per year. The factor provided by EMFAC encompasses the estimated number of cold starts and the idling operation.

- **GHG calculation:** We used the United Nations IPCC GWPs for CO_2 equivalence (CO_2e) on a 100-year timeframe based on the IPCC AR5. For EY2024, we used GWP-100 factors of 28 for CH_4 and 265 for N_2O. Equation 3 presents the GHG calculation based on CO_2e:

Equation 3. GHG Calculation

$$CO_2e = CO_2 + 28 * CH_4 + 265 * N_2O$$

- **GHG and criteria emissions reductions:** The overall reduction in GHGs, NO_X, and SO_X was net of annual emissions from the displaced counterfactual fossil fuel equipment and the electricity consumed by the adopted electric equipment. The overall reduction in $PM_{2.5}$, PM_{10}, CO, and ROG was represented by the annual emissions from the counterfactual vehicle, as these pollutants present localized effects on populations unlike the more globalized effects of the other pollutants. The Team calculated these emissions reductions for sites both inside and outside DACs.

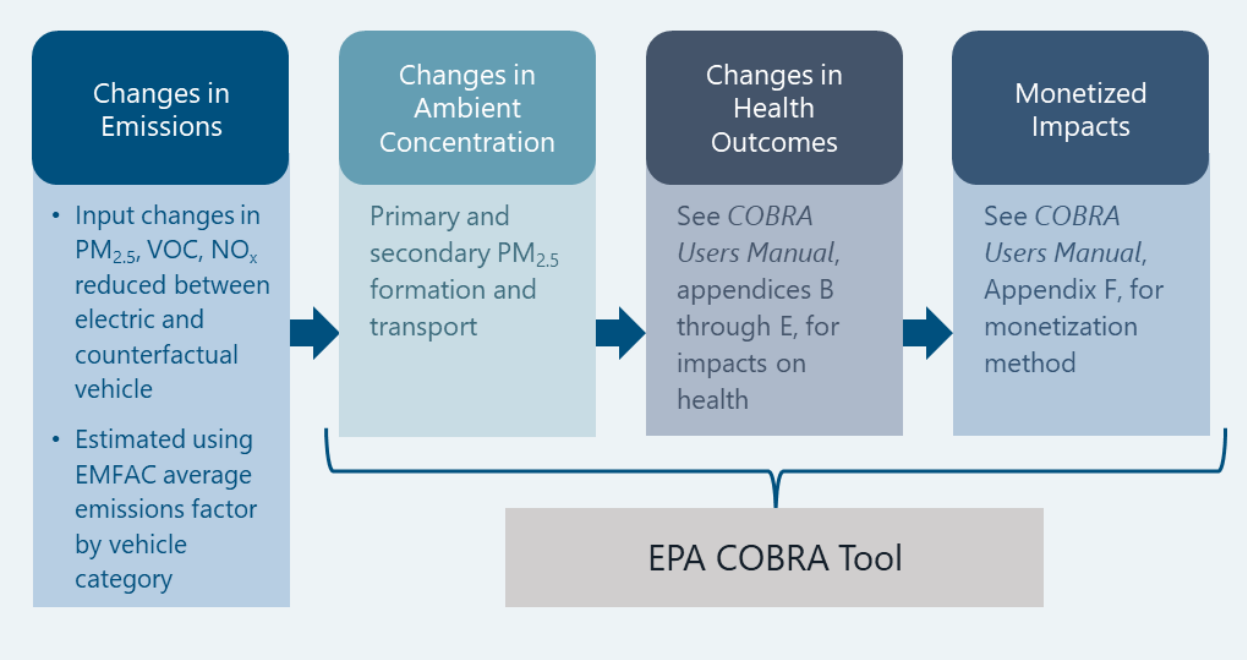
Health Impacts

As EVs replace traditional ICE vehicles, petroleum-based fuels are displaced. These displacements reduce GHG and air pollutant emissions, which may lead to health benefits in regions where EVs are adopted. To understand the effects of the public charging programs on air pollution and related health benefits, the Team estimated the monetized value of health benefits for each individual Utility-funded site by running the emissions reductions through the COBRA. As part of this analysis, we also examined the impact of fossil fuel displacement on DACs. For Liberty, PG&E, and SCE, DACs are identified in the California Communities Environmental Health Screening Tool, CalEnviroScreen, developed by California's Office of Environmental Health Hazard Assessment. SDG&E uses a service territory definition of DAC.[181] This section describes the approach, data sources, and analyses performed to estimate health impacts associated with the public charging programs.

The Evaluation Team used a four-stage methodology to estimate health impacts, shown in Figure B-7 and described below.

[181] As per AL 2876-E, SDG&E found that only 27 census tracts in its territory were considered DACs using the top quartile in the CalEnviroScreen statewide definition. However, the service territory definition is broader and produced a calculated 180 DAC census tracts in SDG&E service territory.

Figure B-7. Four-Step Process for Estimating Health Impacts by Census Tract



Step 1: Changes in Emissions. These estimates are annualized emissions reductions by site for EY2025 in tons for $PM_{2.5}$, VOCs, and NO_x. The Evaluation Team aggregated emissions reductions by county and used those as inputs for COBRA, which uses several fields:

- **Sector** – Highway or off-highway vehicles
- **Subsector #1** – Diesel for most vehicle applications
- **Subsector #2** – Highway or non-road
- **Discount rate** – 2% assumed, which reflects the interest consumers might earn on government-backed securities

The Evaluation Team performed Step 2 through Step 4 using the COBRA desktop version. The Team uploaded the annual reductions in emissions for $PM_{2.5}$, VOCs, and NO_X and the tool output estimates as shown in Table B-22. In this analysis VOCs are assumed to be the same as ROGs, which are the output from EMFAC.

Table B-22. Mapping of Vehicle Types to Sector, Subsector #1, Subsector #2

Vehicle Type	Sector	Subsector #1 (Counterfactual Fuel Type)	Subsector #2 (Counterfactual Fuel Type)	Discount Rate
LDVs (at public charging sites)	Highway	Gasoline fuel	Light duty	2%

Step 2: Changes in Ambient Concentration. COBRA has a feature that uses the reductions in emissions to estimate the change in ambient concentration. The tool also accounts for transport and the transformation of pollutants (for example, into ozone).

Step 3: Changes in Health Outcomes. COBRA uses epidemiological models to estimate the health impacts of emissions changes at the county level. COBRA's estimates reflect the current scientific thinking on the relationship between particulate matter and human health, as well as the economic valuation of these health effects. In particular, the EPA draws from the Integrated Science Assessment for Particulate Matter,[182] and its methodology for characterizing health impacts has been reviewed by two National Academy of Sciences panels and multiple EPA Science Advisory Boards. Because the health impacts of air pollution and approaches to value these impacts are areas of active research, the selection of studies used in COBRA may evolve over time as new evidence and studies emerge. More information is available in the online COBRA documentation.[183] COBRA estimates health impacts for all 3,033 counties in the United States (because of the transport of the pollutants).

Step 4: Monetized Impacts. COBRA estimates the economic value (in 2023 USD) of the change in health impacts from emissions changes at the county level. These values are converted to current year dollars using a multiplier from the U.S. Bureau of Labor Statistics.[184] Economic value is estimated differently depending on health impacts (such as by estimating avoided lost wages, avoided medical costs, the amount people are willing to pay to avoid a negative health impact [such as respiratory symptoms], or the VSL approach, which uses value-of-life studies to determine a monetary value of preventing premature mortality). COBRA reports both a low impact and a high impact, representing uncertainties in the estimates. The low estimate is based on an evaluation of mortality impacts of $PM_{2.5}$ by the American Cancer Society,[185] and the high estimate is based on the Harvard Six Cities mortality study.[186] Rather than average the results of these studies, the EPA's standard practice has been to report the estimated change in mortality separately as low and high values.

Site Visits

The Team conducted site visits for the Public Charging programs during EY2025 to provide qualitative insights on activated EV infrastructure sites. This section describes the approach, data sources, and analyses performed for the EY2025 Public Charging site visits.

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182 U.S. EPA. Last updated January 5, 2026. "Integrated Science Assessment (ISA) for Particulate Matter." www.epa.gov/isa/integrated-science-assessment-isa-particulate-matter

183 U.S. EPA. Last updated February 11, 2026. "Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool." www.epa.gov/cobra/users-manual-co-benefits-risk-assessment-cobra-screening-model

184 U.S. Bureau of Labor Statistics. 2026. "CPI Inflation Calculator." www.bls.gov/data/inflation_calculator.htm

185 Krewski, Daniel et al. May 2009. "Extended Follow-Up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality." Res Rep Health Effects Institute (140): 5–114. pubmed.ncbi.nlm.nih.gov/19627030/

186 Lepeule, Johanna, Francine Laden, Douglas Dockery, and Joel Schwartz. March 28, 2012. "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009." Environmental Health Perspective 120(7): 965–970. www.ncbi.nlm.nih.gov/pmc/articles/PMC3404667/

The Team took a census approach in EY2025, visiting all active sites. The Team collaborated with the Utilities and site hosts, as appropriate, to access each site location. For the analysis, the Team used detailed notes and photos taken during each site visit as well as data provided by the Utilities or online resources. After each site visit, the Team compiled the notes, photos, and completed data into the Arkenstone data collection platform.

The Team analyzed the data to document qualitative insights such as critical design elements including the number of dedicated and other (bonus) parking spots within reach of charging ports, charger signage, distances from surrounding buildings to charging, optimization of the number of vehicles that can charge at one time, competition for parking (such as at convenience stores), and any upgrades made by the Utilities to comply with ADA rules that require additional space for parking and charging. The Team also compared retail rates for charging by station patrons and determined if TOU charges were in place. Finally, the Team quantitatively compared chargers/ports and installed electrical capacity with Utility-provided information.

Site Costs

The Evaluation Team used site-level cost data provided by the Utilities to compile summary statistics of the TTM and BTM costs described below:

- **TTM:** Utility-sponsored costs to construct utility-owned TTM infrastructure taken from SB 350 reporting data provided by the Utilities.
- **Ratepayer BTM:** Either Utility-sponsored costs to construct utility-owned BTM infrastructure or the incentive/rebate amount paid by the Utility for customer-owned infrastructure.
- **All-In BTM:** Either Utility-sponsored costs to construct utility-owned BTM infrastructure or costs estimated using a regression on available costs from sites with cost data.
- **Ratepayer EVSE:** The EVSE rebate amount from the Utility.
- **All-In EVSE:** The full cost of the EVSE equipment and installation assuming L2 ports cost $3,000 per port and DCFC ports cost $45,000 per port for simplicity.

Cost calculations also include the following assumptions:

- The port counts used in the cost-per-port calculations reflect the number of ports reported from site visits. If a site visit did not occur, the Team used the port counts reported by the Utility.
- The vehicle counts used in the cost-per-vehicle calculations are taken from site VAPs.
- The installed capacity values used in the cost-per-kilowatt calculations are the site capacities observed during site visits. If a site visit did not occur, the Team used port capacity totals reported by the Utility.

Interviews

This section describes the approach, data sources, and analyses performed for the EY2025 Utility interviews. The Team conducted phone interviews with Utility staff at SCE, PG&E, SDG&E, and Liberty to provide insight into program design and implementation and context to analysis outputs and findings. For the Public Charging programs, the Team interviewed all Utility program managers to cover a variety of topics about their respective programs.

The Team developed interview guides outlining key topic areas and questions for discussion to ensure that we covered each topic area during the interview:

- Status updates and changes from EY2024 (and before)
- Program design
- Key milestones
- Key barriers to implementation and solutions
- Preliminary areas of success and lessons learned

The Evaluation Team based each interview guide on information previously provided by the Utilities to ensure an effective use of time. A group of Evaluation Team members conducted the interviews to ensure coverage across all relevant evaluation areas.

The Team reviewed verbatim notes taken during each interview as the basis of our analysis. We integrated those findings throughout the report, informing many sections including program overviews, materials reviews, and Utility interview analysis findings.

Appendix C. Data Collection Instruments

Fleet Manager Survey

Fleet Driver Online Survey

Fleet Manager Withdrawal Interview Guide

SRP Evaluation: MDHD Fleet Manager Survey (EY2025)

Survey Purpose: This online survey is designed to engage MDHD fleet managers whose fleets participated in one of the SRP-funded transportation electrification programs. The survey will assess their experience in the program, factors that led to successful electrification, the benefits and costs of electrification, and their view on broader market trends. The survey will be conducted via Qualtrics on a yearly basis. Depending on survey participation rates and count of completed sites, the evaluation team may also consider fielding the survey as a phone survey instead of an online survey.

Research Objectives	Corresponding Question Numbers
1. Identify the factors that facilitate successful fleet electrification and lessons learned	
What strategies lead to viable sites and successful deployments?	C3-C9
What would fleet partners or managers have done differently, if anything?	C15
2. Explore the benefits of TE for fleets and for fleet drivers	
Have fleet partners/managers heard from drivers about their experience? Are there benefits associated with air quality, health, stress, and noise?	D1-D2
How did TCO change after the fleet was electrified, if at all? What were the ongoing costs of fueling and maintenance before/after participating in the program?	E1-E3
3. Asses the experience of fleet partners and managers with the program and infrastructure	
How reliable and user-friendly is the electric vehicle charging equipment?	C3-C6
How, if at all, do fleets engage in load management? Why or why not?	C10-C16
Have fleets experienced any operational tradeoffs or loss of flexibility, and if so, how severe are these impacts?	E1
How satisfied are fleet managers with the program overall? How does overall satisfaction vary by market segment?	B1-B4
4. Gauge market impacts, trends, and identify market barriers	
Which vehicle and market segments are seeing the most uptake? To what degree can we expect that to change as other incentives are scaled up or scaled back, and as technology and costs improve?	F1-F2, F7-F8
What are the barriers to fleet electrification and how do these differ by vehicle or market segment?	F3-F4
How did the program change electrification within fleets, and do the fleets plan to accelerate TE-related procurement because of the experience?	F5-F6, F10-F11
5. Assess program attribution	
What type of transportation electrification project would participants have undertaken in absence of the utility program? Have the fleets decided to electrify more of their fleets without incentives from the fleet electrification program or another organization, due to their participation in the fleet electrification program?	G1-G5, H1-H5

Target Audience: Fleet Managers of operational sites

Desired number of completions: Census of all operational sites (sites where AMI and/or EVSP data were received from the Utility or EVSP) per utility. The below are cumulative completion totals across the entire program cycle. We will determine completion targets for each utility during each fielding wave.

- Liberty: 1
- PG&E: 700
- SCE: 870
- SDG&E: 300

Estimated timeline for fielding: Survey to be fielded after each site visit wave.

Variables to be Pulled into Survey:

- **Email**
- **FirstName**
- **LastName**
- **UTILITY (SCE/SDGE&E/PG&E/Liberty; read-in)**
- **PROGRAM_NAME (read-in; do not include "program")**
- **Organization**

Variables in survey

- **BUILD-OUT (set as YES or NO based on A0)**
- **OPERATIONS (set as YES or NO based on A0)**

Sample Fleet Manager Contact Info Collection Email

To: [EMAIL – Site Host]
From: [Cadmus]

CC: [SCE/SDG&E/PG&E/Liberty MDHD PM and Customer Account Manager]
Subject: Survey with fleet managers for the [UTILITY] fleet electrification program

Dear [FirstName AND LastName],

Thank you for working with [UTILITY] to expand transportation electrification. As part of our evaluation of the [UTILITY]'s [PROGRAM_NAME] program, we are surveying fleet managers from each activated project about their experience during installation, their fleet operations, and the benefits/costs of transportation electrification. Could you please provide the contact information (name, title, email, phone) for the most appropriate person within your organization so we may reach out to them and invite them to complete the 20-minute online survey?

Survey results are anonymized and the utility will not be able to see respondents' individual responses.

Thank you,

CADMUS PERSON'S FIRST AND LAST NAME
THEIR TITLE
CADMUS GROUP

CLIENT CONTACT PERSON'S FIRST AND LAST NAME
THEIR TITLE
COMPANY NAME

Email Invitation

To: [EMAIL]
From: [Cadmus]

CC: [SCE/SDG&E/PG&E/Liberty MDHD PM and Customer Account Manager]
Subject: Your experience with the [SCE/SDGE&E/PG&E/Liberty] fleet electrification program

Dear [FirstName AND LastName],

As part of [UTILITY]'s fleet electrification program evaluation, we invite you to share your opinion about your experience electrifying your fleet. Your experience can provide valuable feedback about how to improve the program experience for other fleets. Your input is very important to us and will be anonymized and only used for research purposes – utilities will not be able to see individual responses. **The survey will take about 20 minutes to complete**.

Click the link below to take the survey (or copy and paste into your browser):

[auto-generated link]

If you feel that someone else is better positioned to answer this survey, could you please forward the email to that person and copy [redacted]@cadmusgroup.com?

If you have any questions about this research, or any difficulties taking the survey, please contact [redacted] at The Cadmus Group, the national research firm conducting this survey for the utilities. You can reach [redacted] by replying directly to this email or by calling ([redacted]) [redacted]-[redacted].

Thank you in advance for sharing your experiences and your time.

CADMUS PERSON'S FIRST AND LAST NAME
THEIR TITLE
CADMUS GROUP

CLIENT CONTACT PERSON'S FIRST AND LAST NAME
THEIR TITLE
COMPANY NAME

Reminder Invitation

To: [EMAIL]
From: [SCE/SDG&E/PG&E/Liberty] Feedback
Subject: We still want to hear about your experience with the [SCE/SDG&E/PG&E/Liberty] transportation electrification program!

Dear [FirstName AND LastName],

We recently invited you to tell us about your experience with the [UTILITY] fleet electrification program. Your experience can provide us with valuable feedback that can help improve program experience for participating fleets. Your input is very important to us, will be kept confidential, and only used to improve our programs for customers like you. **Please take 20 minutes today to complete the survey**. Survey results are anonymized and the utility will not be able to see respondents' individual responses.

Click the link below to take the survey (or copy and paste into your browser):

[auto-generated link]

If you feel that someone else would be better positioned to answer this survey, could you please forward the email to that person and copy [redacted]@cadmusgroup.com?

If you have any questions about this research, or any difficulties taking the survey, please contact [redacted] at The Cadmus Group, the national research firm conducting this survey on our behalf. You can reach [redacted] by replying directly to this email or by calling ([redacted]) [redacted]-[redacted].

Thank you in advance for sharing your experiences and your time.

CADMUS PERSON'S FIRST AND LAST NAME
THEIR TITLE
CADMUS GROUP

CLIENT CONTACT PERSON'S FIRST AND LAST NAME
THEIR TITLE
COMPANY NAME

Survey Introduction and Screener

Welcome! Thank you for sharing your experience with the **[PROGRAM_NAME] program**, offered by **[UTILITY]**. This survey will take about 20 minutes to complete and will ask questions about fleet electrification and the benefits of transportation electrification. Your responses will remain confidential.

[SCREEN OUT TERMINATION MESSAGE:] Those are all the questions we have. Thank you.

A. Overview & Background Information

To begin, we'd like to ask you some general background questions.

A0. Which of the following statements describes your familiarity with the fleet that you electrified through the **[PROGRAM_NAME]** program? **[REQUIRED]**

1. I am familiar with **both** the **build-out of the charging infrastructure** AND the **fleet operations** **[SET BUILD-OUT=YES AND OPERATIONS=YES]**
2. I am **only** familiar with the **build-out of the charging infrastructure** **[SET BUILD-OUT=YES AND OPERATIONS=NO]**
3. I am **only** familiar with the **fleet operations** **[SET BUILD-OUT=NO AND OPERATIONS=YES]**
4. I am not familiar with either **[SET BUILD-OUT=NO AND OPERATIONS=NO]**

[ASK IF OPERATIONS=NO] A0a. Please provide us with the name, email address, and phone number of the best contact at your organization to ask about the **fleet operations**. **[REQUIRED]**

1. Name: **[TEXT]**
2. Email address: **[TEXT]**
3. Phone number: **[TEXT]**

[ASK IF BUILD-OUT=NO] A0b. Please provide us with the name, email address, and phone number of the best contact at your organization to ask about the **build-out of the charging infrastructure**. **[REQUIRED]**

1. Name: **[TEXT]**
2. Email address: **[TEXT]**
3. Phone number: **[TEXT]**

[IF BUILD-OUT=NO AND OPERATIONS=NO, DISPLAY MESSAGE: "Thank you for providing the best contact information for a colleague to ask about the fleet build-out and operations. We will reach out to them directly. Have a nice day." **[TERMINATE]**

[ASK IF BUILD-OUT=YES OR OPERATIONS=YES]

A1. What types of vehicles/equipment do you have in your fleet? **[SELECT ALL THAT APPLY; FORCE RESPONSE]**

1. School bus
2. Transit bus
3. Medium-duty vehicles
4. Heavy-duty vehicles
5. Port cargo trucks
6. Airport ground support equipment
7. Forklifts
8. Truck refrigeration unit

9. Truck stop electrification technology
10. Other (#1) **[PLEASE SPECIFY]**
11. Other (#2) **[PLEASE SPECIFY]**
12. Other (#3) **[PLEASE SPECIFY]**

CREATE EMBEDDED DATA BASED ON RESPONSE TO 0:
IF 0 = 1, school_bus = TRUE
IF 0 = 2, transit = TRUE
IF 0 = 5, port = TRUE
IF 0 = 6, airport = TRUE
IF 0 = 7, forklift = TRUE
IF 0 = 8, distribution = TRUE

A2. Please specify the number of internal combustion engine and electric vehicles **currently in your fleet**:

	(1) Number of internal combustion engine vehicles	**(2) Number of electric vehicles**
[VEHICLE SELECTED IN 0]		
[VEHICLE SELECTED IN 0]		
[VEHICLE SELECTED IN 0]		
[VEHICLE SELECTED IN 0]		
Other vehicle type; please specify: [OPEN END]		
Other vehicle type; please specify: [OPEN END]		
Total Vehicles	**[AUTOSUM]**	**[AUTOSUM]**

A3. Please specify the number of electric vehicles/equipment that you **plan to acquire in the next 5 years and in the next 10 years.**

	(3) Number of electric vehicles you plan to acquire in the next 5 years	**(4) Number of electric vehicles you plan to acquire in the next 10 years**
[VEHICLE SELECTED IN 0]		
[VEHICLE SELECTED IN 0]		

[VEHICLE SELECTED IN 0]		
[VEHICLE SELECTED IN 0]		
Other vehicle type; please specify: [OPEN END]		
Other vehicle type; please specify: [OPEN END]		
Total Vehicles	**[AUTOSUM]**	**[AUTOSUM]**

A4. Are there any other types of vehicles/equipment you plan to electrify in the next 10 years? If so, please state the vehicle/equipment type, the number of vehicles, and the rough timeframe.
1. **[OPEN END]**

A5. Did your participation in the **[PROGRAM_NAME]** program change the number of electric vehicles you acquired or planned to acquire? **[FORCE RESPONSE]**
1. Yes
2. No

A6. **[ASK IF A5=1]** How did your participation in the **[PROGRAM_NAME]** program change the number of electric vehicles you acquired or planned to acquire? Please specify the vehicle type, the change in number of vehicles, and the timeframe.
1. **[OPEN END]**

A7. Since site completion, approximately how many medium- and heavy-duty internal combustion vehicles/equipment have been retired?
1. **[OPEN END]**

A8. Roughly what percent of your fleet's routes are within disadvantaged communities? If you are unsure about which communities are designated as disadvantaged, please reference this map from the CA State government and try to give your best guess.
1. **[DROPDOWN WITH PERCENTAGE RANGES OF 10% INCREMENTS]**

B. Program Experience

[ASK IF BUILD-OUT=YES]

Now, we'd like to ask you a few questions about your experience in **[UTILITY] [PROGRAM_NAME]** program.

B1. Thinking about your experience with the **[PROGRAM_NAME]** program, how satisfied are you with the following? **[SELECT ONE PER ROW]**

	Very satisfied	Somewhat satisfied	Not too satisfied	Not at all satisfied
[SKIP FOR LIBERTY] Application process (through signing of program participation agreement - includes site assessment and conceptual design)				
Design and permitting process (detailed site design, easement, permitting)				
Construction and installation process (infrastructure construction and installation of customer-side, behind-the-meter infrastructure)				
Rebate process (documentation processing, rebate receipt)				
Amount of the rebate you received or expect to receive from **[UTILITY]** for the purchase of EV charging equipment, if eligible				
Amount of the rebate you received or expect to receive from **[UTILITY]** for the installation of customer-side, behind-the-meter infrastructure, if eligible				
Benefits you received through the program (i.e., provision of utility-side, to-the-meter infrastructure by **[UTILITY]**)				
Experience working with [UTILITY] staff				
[PROGRAM_NAME] program overall				

B2. Are there aspects of the **[PROGRAM_NAME]** program that you were particularly **satisfied** with? If so, which ones, and why?
   1. **[OPEN ENDED]**

B3. Are there aspects of the **[PROGRAM_NAME]** program that you were particularly **dissatisfied** with? If so, which ones, and why?
   1. **[OPEN ENDED]**

B4. On a scale from 0 to 10, with '10' being the most likely, how likely would you be to recommend this program to another company?
   1. **[RECORD 0-10 RATING; IF STATING "ALREADY DID RECOMMEND", CODE AS 10]**

B5. Have you shared anything about the program with another company?
   1. Yes
   2. No
   3. Don't know

B6. **[IF B5=1]** What did you share about the program with them?
   1. **[OPEN END]**

C. *Factors Leading to Successful Fleet Electrification and Lessons Learned*

Now, we'd like to talk to you about the fleet electrification process.

C1. **[ASK IF BUILD-OUT=YES]** Why did your fleet decide to transition to EVs? (Select all that apply.) **[MULTIPLE RESPONSE] [RANDOMIZE 1-10]**

1. Regulatory requirement
2. Corporate/organizational sustainability goals or initiatives
3. Expected fuel cost savings
4. Expected maintenance cost savings
5. Better technology
6. Driver comfort/ preference
7. Environmental benefits
8. Rebates/incentives for EVs
9. Rebates/incentives for EV charging infrastructure
10. Operational benefits
11. Other, please specify: **[OPEN ENDED]**

C2. **[ASK IF BUILD-OUT=YES]** How did you first learn about the **[PROGRAM_NAME]** program? If there were multiple sources, please select the primary source.

1. From **[UTILITY]**
2. From an EV/EVSE manufacturer
3. From a contractor/engineer
4. From another fleet
5. Another source, please specify: **[OPEN ENDED]**

C3. **[ASK IF OPERATIONS=YES]** How would you rate the reliability of the electric vehicles that are part of your fleet?

1. Very reliable
2. Somewhat reliable
3. Not too reliable
4. Not at all reliable

C4. **[ASK IF OPERATIONS=YES]** How would you rate the reliability of the electric vehicle charging equipment? **[FORCE RESPONSE]**

1. Very reliable
2. Somewhat reliable
3. Not too reliable
4. Not at all reliable

C5. **[IF C4 = 3 OR 4]** What challenges have you had with the reliability of the electric vehicle charging equipment?

1. **[OPEN ENDED]**

C6. **[ASK IF OPERATIONS=YES]** How would you rate the ease of using the electric vehicle charging equipment?

1. Very easy to use
2. Somewhat easy to use
3. Not too easy to use
4. Not at all easy to use

C7. **[ASK IF BUILD-OUT=YES]** **Prior to joining the program**, did you know that you needed **upgrades to the electrical infrastructure from the utility grid to your meter** to charge electric vehicles at your site?

1. Yes
2. No

C8. **[ASK IF BUILD-OUT=YES]** Did your site design, procure, install, and maintain the make-ready infrastructure on the customer side of the meter, or did the utility do this work?

1. Our site
2. The utility
3. Don't know

C9. **[ASK IF OPERATIONS=YES]** Do you regularly receive information on, or know where to find out how much your electric fuel costs?

1. Yes
2. No

C10. **[ASK IF OPERATIONS=YES]** Are you aware that the utility charges different rates per kilowatt-hour depending on the time of day?

1. Yes
2. No

C11. **[ASK IF OPERATIONS=YES]** Are you aware of the cost to your company to charge your fleet?

1. Yes
2. No

C12. **[ASK IF OPERATIONS=YES]** **[GRID IMPACTS]** What actions, if any, do you take to ensure you are purchasing the lowest cost electricity for charging fleet vehicles? A term you may have heard for this is "load management." (Select all that apply.) **[RANDOMIZE CHOICES]**

1. By training drivers or other staff to plug in vehicles during off-peak times
2. By using load management software of my fleet's EVs or EV charging equipment
3. Our fleet does not engage in load management **[EXCLUSIVE]**
4. Other, please specify: **[OPEN ENDED]**

C13. **[GRID IMPACTS]** **[ASK IF C12=1 OR 2]** Why did you implement a load management strategy? (Select all that apply.) **[RANDOMIZE CHOICES]**

1. Required to implement it; please specify who/what entity required load management: **[OPEN ENDED]**
2. Lower cost of charging via charging time management
3. Manage stability of our electrical system
4. Reduce the need to install additional power source(s)
5. Other, please specify: **[OPEN ENDED]**

C14. **[GRID IMPACTS]** **[ASK IF C12=4]** Why do you not currently engage in load management? (Select all that apply.) **[RANDOMIZE CHOICES]**

1. Not interested
2. Do not have the capacity to put it into place/manage the process
3. Not required to implement it
4. Too complicated to implement
5. Issues with the software working as intended
6. Compatibility issues with software/chargers/vehicles
7. Site has not been operational long enough
8. Other, please specify: **[OPEN ENDED]**

C15. **[GRID IMPACTS]** **[ASK IF C12=4]** If you don't currently engage in load management, how, if at all, do you plan to? (Select all that apply.)

1. By training drivers or other staff to plug in vehicles during off-peak times
2. By using load management options of my fleet's EVs or EV charging equipment
3. By using a software program
4. Our fleet does not plan to engage in load management **[EXCLUSIVE]**
5. Other, please specify: **[OPEN ENDED]**

C16. **[ASK IF OPERATIONS=YES]** What factor(s) were important in your decision regarding which network provider you selected for charging capabilities? (Select all that apply.)

1. The monthly fee charged by the network provider
2. The specific operations and maintenance services offered by the network provider
3. Superior customer service interface and responsiveness of the network provider
4. The network provider was responsible for implementation load management
5. They were the only provider who responded to our RFP
6. Recommended by a contractor/person within the industry
7. Other, please specify: **[OPEN ENDED]**

C17. **[ASK IF BUILD-OUT=YES OR OPERATIONS=YES]** Thinking about the complete process of electrifying your fleet, what would you have done differently if you were to go through it again, if anything?

1. **[OPEN ENDED]**

D. Additional Benefits of Transportation Electrification

[ASK IF OPERATIONS=YES]

Next, we would like to ask you questions about the benefits of transportation electrification and fleet drivers' experience.

D1. What ancillary benefits do you think will be realized for your community/fleet as a result of electrifying? These could be benefits to any party, such as your company, your drivers, or your community, among others. **[SELECT ONE PER ROW]**

	I think there will be significant benefits	**I think there will be some benefits**	**I think there will be no benefits**	**Not sure**
Improved air quality/health (i.e., breathing in less pollution)				
Improved driver/passenger comfort/convenience (i.e., easier to drive, smoother to ride in)				
Reduction in noise pollution (i.e., quieter when driving, accelerating)				
Increased fleet flexibility				
Encourages other individuals or fleets to convert to EV				

D2. What other benefits, if any, do you think will be realized for your community/fleet as a result of electrifying? These could be benefits to any party, such as your company, your drivers, or your community, among others.

1. **[OPEN END]**

E. Cost of Transportation Electrification

[ASK IF OPERATIONS=YES]

Next, we will ask about the operational and ownership costs of fleet electrification.

E1. Please think about all the costs associated with operating and maintaining your fleet. For each cost type shown below, please estimate how much the cost has changed since transitioning your fleet to EVs.

Compared to before transitioning to EVs…

	Costs are now lower	Costs are relatively equal	Costs are now higher	Don't know
Vehicle maintenance costs (i.e., purchasing replacement parts, labor to complete repairs, and regular maintenance)				
Vehicle fueling costs (i.e., the cost of fuel)				
Vehicle fueling infrastructure costs (i.e., the costs of the equipment needed to fuel your fleet)				
Training – drivers				
Training – maintenance staff				
Cost of additional support/staff time				
Cost of additional time on warranty or service claims				
Cost of fueling schedule modifications				
Cost of changes to parking lot configuration				
Cost of route modifications to accommodate range limitations of EVs				
Loss of flexibility				

E2. Have these operational and maintenance costs been what you expected?

	Yes	No, lower than expected	No, higher than expected	Don't know
Vehicle maintenance costs (i.e., purchasing replacement parts, labor to complete repairs, and regular maintenance)				
Vehicle fueling costs (i.e., the cost of fuel)				
Vehicle fueling infrastructure costs (i.e., the costs of the equipment needed to fuel your fleet)				
Training - drivers				
Training – maintenance staff				
Cost of additional support/staff time				
Cost of additional time on warranty or service claims				
Cost of fueling schedule modifications				
Cost of changes to parking lot configuration				
Cost of route modifications to accommodate range limitations of EVs				
Cost of needing to maintain ICE vehicles for routes or events that cannot be reliably served by EVs				

E3. Have there been any other impacts/costs you've incurred as a result of electrifying? This could include costs for items such as employee labor, equipment purchases, or space utilization, among others.
   1. **[OPEN END]**

F. Market Impacts, Trends, and Market Barriers

[ASK IF BUILD-OUT=YES OR OPERATIONS=YES]

Next, we'd like to ask you about the broader market and what may be preventing further electrification.

F1. How well positioned do you think your industry/sector is for electrification?
   1. Extremely well-positioned
   2. Somewhat well-positioned
   3. Neutral
   4. Not too well-positioned
   5. Not at all well-positioned

F2. Why did you give this rating?
   1. **[OPEN ENDED]**

F3. Which of the following barriers to electrification did your fleet face before participating in the **[PROGRAM_NAME]** program? **[MULTIPLE RESPONSE; RANDOMIZE 1 – 6; FORCE RESPONSE]**
   1. The cost of the EVs was prohibitive
   2. The cost of installing EV charging infrastructure was prohibitive
   3. It was challenging to find the right types of EVs for our needs
   4. Our routes were too long for the EVs available
   5. There was insufficient charging equipment on/near our routes
   6. Finding qualified drivers or maintenance technicians for EVs
   7. Other, please specify: **[OPEN ENDED]**
   8. None of the above **[EXCLUSIVE]**

F4. You mentioned that the following were barriers to electrification before participating in the **[PROGRAM_NAME]** program. Do any of these barriers **still exist after you participated in the program? [INSERT OPTIONS SELECTED IN F3; MULTIPLE RESPONSE; RANDOMIZE 1 - 6]**
   1. The cost of the EVs was prohibitive
   2. The cost of installing EV charging infrastructure was prohibitive
   3. It is challenging to find the right types of EVs for our needs
   4. Our routes are too long for the EVs available
   5. There is insufficient charging equipment on/near our routes
   6. Finding qualified drivers or maintenance technicians for EVs
   7. **[OPEN-ENDED RESPONSE IF OTHER WAS SELECTED]**
   8. None of the above

F5. Do you plan to accelerate procurement of EVs and related equipment because of your experience with the program? **[FORCE RESPONSE]**
   1. Yes
   2. No change
   3. No, we plan to slow procurement

F6. **[IF F5= 1]** What aspect(s) of the program have impacted your decision to accelerate your procurement of EVs?
   1. **[OPEN ENDED]**

F7. Are you satisfied with current EV options on the market for your sector?
   1. Yes
   2. No

F8. What are the limitations of current EV options for your sector?
   1. **[OPEN ENDED RESPONSE]**

F9. What types of technologies and processes, if any, have been particularly helpful in electrifying your fleet?
   1. **[OPEN ENDED RESPONSE]**

F10. The purchase price and operating costs (fuel and maintenance) of electric trucks may differ from those of diesel trucks. Given what you know or believe about requirements for fleets to purchase zero-emission medium- and heavy-duty trucks, do electric or diesel trucks seem like a riskier purchase in the **next 3 years**? **[RANDOMIZE ORDER]**

   In the **next 3 years…**
   1. **Electric trucks** seem like a riskier purchase
   2. **Diesel trucks** seem like a riskier purchase

F11. Given what you know or believe about requirements for fleets to purchase zero-emission medium- and heavy-duty trucks, do electric or diesel trucks seem like a riskier purchase in the **next 10 years**? **[RANDOMIZE ORDER]**

   In the **next 10 years…**
   1. **Electric trucks** seem like a riskier purchase
   2. **Diesel trucks** seem like a riskier purchase

G. Attribution – Freeridership

[ASK IF BUILD-OUT=YES]

G1. If the **[UTILITY]** fleet electrification program had not been available, which of the following alternatives would your organization most likely have done?

1. Proceeded with a smaller, but similar transportation electrification project (Please specify how much smaller in terms of electric vehicles/chargers (e.g. 10% less, 40% less, etc): _____)
2. Installed/procured an internal combustion engine (ICE) transportation project or whatever was required by regulation
3. Done nothing within 20 years
4. Applied for an exemption
5. Done the same thing as completed through the program
6. Something else **(Please specify: _____)**

G2. **[ASK IF G1≠G1.3, G1.6]** You said previously that your organization would have **[G1 RESPONSE].** In terms of timing, if the **[UTILITY]** fleet electrification program had not been available, when would your organization have **[G1 RESPONSE]**?

1. At the same time
2. Later, but within 5 years
3. Between 5 and 10 years
4. Between 10 years and 15 years
5. Between 15 years and 20 years
6. More than 20 years
7. Something else **(Please specify: _____)**

G3. Did your organization learn about the **[UTILITY]** fleet electrification program **BEFORE** or **AFTER** you decided to implement the transportation electrification project that was eventually implemented?

1. Before
2. After

G4. Please allocate 10 points on the overall importance of the following utility **program factors** versus the most important **non-program factors** in your organization's decision to procure the transportation electrification project. Using a 0 to 10 rating scale, where 0 means "not at all important" and 10 means "extremely important". **Please ensure that the two ratings total 10.**

1. **[Record Program Factors Rating]**
2. **[Record Non-Program Rating]**

Program Factors

A. The availability of the utility program incentives, rebates, or discounts
B. Recommendations or suggestions from utility program staff
C. Recommendations or suggestions from your utility account representative
D. Recommendations or suggestions from a program vendor or contractor

Non-Program Factors

A. Funding sources outside of the utility program
B. Internal policy or requirements inside your company or organization
C. **[DISPLAY IF transit=TRUE]** Transit agency requirements to purchase zero emission buses by January 2023 (for large fleets, acquisition must be 25% for 2023-2025, 50% for 2026-2028, 100% in 2029; for small fleets, 25% for 2026-2028, 100% for 2029)
D. **[DISPLAY IF distribution=TRUE]** Distribution fleets requirements to meet CARB's pending zero-emission operation targets in 2024 and 2025 (acquisition must be 100% ZEV starting in 2024 OR hit fleet levels of 10% by 2025, 25% by 2028, 50% by 2031, 75% by 2033, 100% by 2035)
E. **[DISPLAY IF airport=TRUE]** Airport group support equipment requirements to meet their initial 2027 compliance targets
F. **[DISPLAY IF school_bus=TRUE]** School bus requirements in consideration to meet potential future compliance targets
G. **[DISPLAY IF port=TRUE]** Port cargo truck requirements to meet their initial 2024 compliance targets
H. **[DISPLAY IF forklift=TRUE]** Forklift requirements to meet their future compliance targets
I. Concerns about environmental effects or global warming
J. Your organization's desire to save money on transportation energy costs
K. Your interest in the transportation electrification technology
L. Your desire to reduce operations and maintenance costs
M. Your desire to have the latest technology
N. Your desire to procure transportation electrification to attract employees, for your employees or to improve employee morale

G5. If the utility program had not been available, what is the likelihood that you would have procured exactly the same program-qualifying transportation electrification project that you did through the program. Use a likelihood scale from 0 to 10, where 0 is "not at all likely" and 10 is "extremely likely".

1. **[Record Likelihood Rating]**

H. Attribution – Participant Spillover

[ASK IF BUILD-OUT=YES]

H1. Since you started participating in the program, has your organization decided to go beyond the electrification commitments you made in the Vehicle Acquisition Plan (VAP) **without incentives** from the **[UTILITY]** fleet electrification program?

1. Yes
2. No **[SKIP TO CLOSING]**

98. Don't know **[SKIP TO CLOSING]**

H2. **[ASK IF H1=1]** Please describe the additional electrification your organization has decided to pursue without support from the **[UTILITY]** fleet electrification program.

1. **[RECORD VERBATIM]**

	(H2.1) Describe vehicle type:	**(H2.2) Specify the number of vehicles:**	**(H2.3) Specify the number of new chargers you installed:**	**(H2.4) Additional notes:**
First vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]
Second vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]
Third vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]
Fourth vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]
Fifth vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]

H3. **[ASK IF H1=1]** Did you receive any financial support from **any** organization for **any** of the additional electrification you noted above? **[FORCED RESPONSE]**

1. Yes
2. No

98. Don't know

H4. **[ASK IF H3=1 & IF H2.1 NOT EMPTY]** H4.1. What organizations provided the financial support? H4.2. What type and amount of financial support did you receive from each?

	(H4.1) What organization provided the financial support?	**(H4.2) What type and amount of financial support did you receive?**	**(H4.3) What aspects of the additional electrification did the financial support cover (i.e., chargers, vehicles, both)?**
First vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]
Second vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]
Third vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]
Fourth vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]
Fifth vehicle type	[RECORD VERBATIM]	[RECORD VERBATIM]	[RECORD VERBATIM]

H5. **[ASK IF H1=1]** How important was your participation in the **[UTILITY]** fleet electrification program on your decision to pursue additional electrification without program support? Please use a scale from 0 to 10, where 0 is "not at all important" and 10 is "extremely important."

1. **[RECORD RATING]**

End of Survey Message

Thank you for your responses! In addition to this survey, we are also conducting interviews with a select number of fleet managers to discuss specific topics. We may reach out to you in the future about an interview. We appreciate your time and assistance.

CADMUS

SRP Evaluation: Fleet Driver Online Survey EY2025

This survey is designed to assess participating fleet drivers' experience driving a Medium-Duty and/or Heavy-Duty (MDHD) Electric Vehicle (EV) as a part of the California Transportation Electrification Standard Review Projects. Questions in this survey pertain to the user experience, observed benefits, and challenges associated with the EV and related charging infrastructure. This survey should take approximately 15 minutes for the driver to complete.

Research Objectives	Corresponding Question Numbers
1. Assess participating driver experience with EV infrastructure	
Did drivers receive training to operate an EV?	A8 - A11
How satisfied are fleet drivers with their EV, including its range, and its charging station(s)?	B1 - B5
How reliable and user-friendly are the charging stations?	B8 - B9
2. Explore the benefits/operational impacts of TE for fleet drivers	
Have drivers observed any benefits of electrification associated with improved air quality and health outcomes?	C2 - C3
Have drivers observed any benefits of electrification associated with comfort or convenience?	C4 - C5
Have drivers observed any benefits of electrification associated with noise pollution?	C6 - C7
Have drivers experienced challenges driving an EV or using the associated EV charging stations? Have the charging stations been sufficient?	D1 - D4
How has a driver's job changed now that they are driving an EV?	D5

Target Audience: Fleet drivers in California Standard Review Projects

Target Quota = Representative sample of drivers from a subset of fleets (final sampling TBD)
General Instructions

- Interviewer instructions are in green **[LIKE THIS]** (the style is "Survey: Interviewer Instructions").
- CATI programming instructions are in red **[LIKE THIS]** (the style is "Survey: Programming").
- Items that should not be read by the interviewer are in parentheses like this ( ).

Variables to be Pulled into Survey

- Company name
- Utility name
- Program Name

Survey Introduction and Screener

[RECOMMENDED: CLIENT-APPROVED LOGO TO APPEAR ON START SCREEN]

Welcome! Thank you for sharing your experience with driving an electric vehicle, whose charging infrastructure was supported through the **[PROGRAM NAME]** program, offered by **[SCE/SDG&E/PG&E/Liberty]**. This survey will take 15 minutes to complete and will ask questions about your experience driving an EV and using the associated charging infrastructure.

Your responses will remain confidential and will only be used for research purposes.

[SCREEN OUT TERMINATION MESSAGE:] Those are all the questions we have. Thank you for taking the time to complete this survey.

A. Background

The following questions pertain to background information on your current role, any relevant training you received, and your level of satisfaction with the EV you drive and its associated charging stations.

A1. What type of electric vehicle do you primarily operate? **[SINGLE RESPONSE]**
1. School Bus
2. Transit Bus
3. Medium-duty vehicles
4. Heavy-duty vehicles
5. Port cargo trucks
6. Airport ground support equipment
7. Forklift
8. Vehicle with an electric transport refrigeration unit (eTRU)
9. Other **[WITH WRITE IN OPTION]**
10. I do not drive an electric vehicle for **[COMPANY NAME]**.

A2. When (month/year) did you begin **operating the EV**/EV equipment for your company's/organization's fleet?
1. **[OPEN ENDED RESPONSE]**

A3. How often do you charge the EV/EV equipment you operate for **[COMPANY NAME]**?
1. Less than once per day
2. Once per day
3. Twice per day
4. More than twice per day

A4. What time(s) of day do you typically charge the EV/EV equipment? **[ACCEPT MULTIPLE RESPONSES]**
1. Morning
2. Night
3. Middle of the day
4. Other **[WITH WRITE IN OPTION]**

A5. How much time is needed to charge the EV/EV equipment to be ready for your shift?
1. Less than 30 minutes
2. 30 minutes – 1 hour
3. 1-3 hours
4. 3-5 hours
5. 5-7 hours
6. More than 7 hours
98. Don't know

A6. How much time is needed to fully charge the EV/EV equipment?
1. Less than 30 minutes
2. 30 minutes – 1 hour
3. 1-3 hours
4. 3-5 hours
5. 5-7 hours
6. More than 7 hours
98. Don't know

A7. How many miles do you typically drive the EV/EV equipment on your shift for **[COMPANY NAME]**? Would you say:
1. Less than 25 miles
2. 25-74 miles
3. 75-124 miles
4. 125-174 miles
5. 175-224 miles
6. 225 miles or more
98. Don't know

A8. Did you receive any training to operate your EV/EV equipment?
1. Yes **[ASK A9-A11]**
2. No

[ASK A9-A11 IF A8 = YES]

A9. What did the training to operate the EV/EV equipment consist of? **[MULTI-SELECT]**
1. Received a training manual to operate the vehicle/equipment
2. Received a training manual to charge the vehicle/equipment at the charging station
3. Received onsite training to operate the vehicle/equipment
4. Received onsite training to charge the vehicle/equipment at the charging station
5. Other **[WITH WRITE IN OPTION]**

A10. Who provided the training? Was it:
1. Your company
2. The vehicle/equipment original equipment manufacturer (OEM)

3. The vehicle/equipment distributor/supplier
4. The charging station provider
5. Other **[WITH WRITE IN OPTION]**

98. Don't know

A11. How helpful was the training?

1. Very helpful
2. Somewhat helpful
3. Not too helpful
4. Not helpful at all

B. User Experience and Satisfaction

The following questions are designed to gain a better sense of your experience driving an EV and using the related charging equipment.

B1. How satisfied are you with the experience of operating the EV/EV equipment?

1. Very satisfied
2. Somewhat satisfied **[ASK B2]**
3. Not too satisfied **[ASK B2]**
4. Not satisfied at all **[ASK B2]**

[ASK IF B1= 2, 3, OR 4]

B2. Why do you say you are **[INSERT SELECTED OPTION]** with your experience operating the EV/EV equipment?

1. **[OPEN ENDED RESPONSE]**

B3. How satisfied are you with the range of your EV/EV equipment?

1. Very satisfied
2. Somewhat satisfied
3. Not too satisfied
4. Not satisfied at all

B4. How satisfied are you with your experience using the charging stations at your company's site?

1. Very satisfied
2. Somewhat satisfied **[ASK B5]**
3. Not too satisfied **[ASK B5]**
4. Not satisfied at all **[ASK B5]**

[ASK IF B4 = 2, 3, OR 4]

B5. Why do you say you are **[INSERT SELECTED OPTION]** with using the charging stations?
1. **[OPEN ENDED RESPONSE]**

B6. How reliable would you say the EV/EV equipment you operate is?
1. Very reliable
2. Somewhat reliable **[ASK B7]**
3. Not too reliable **[ASK B7]**
4. Not at all reliable **[ASK B7]**

[ASK IF B6 = 2, 3, OR 4]

B7. Why do you say the EV/EV equipment is **[INSERT SELECTED OPTION]**?
1. **[OPEN ENDED RESPONSE]**

B8. Compared to operating a vehicle with an internal combustion engine, would you say **operating the EV/EV equipment** is overall:
1. Easier to drive
2. About the same driving experience
3. Not as easy to drive

B9. Compared to refueling a vehicle with an internal combustion engine, would you say **using the charging stations for the EV/EV equipment** is overall:
1. Easier to use
2. About the same user experience
3. Less easy to use

C. Benefits of Operating an EV/EV Equipment

The following questions pertain to your experience operating the EV/EV equipment compared to an internal combustion engine vehicle/equipment.

C1. Since you began operating the EV/EV equipment for **[COMPANY NAME]**, what benefits, if any, have you noticed compared to operating an internal combustion engine vehicle or equipment?
1. **[OPEN ENDED]**
2. I have not noticed any benefits

C2. Based on your experience operating the EV/EV equipment, have you noticed an **improvement in air quality or health**, such as reduced exposure to exhaust, compared to operating internal combustion engine vehicles or equipment?
1. Yes, I've **definitely** noticed this **[ASK C3]**
2. Yes, I've **somewhat** noticed this **[ASK C3]**
3. No, I have not noticed this

[ASK IF C2 = 1 OR 2]

C3. Which air quality or health improvements have you observed?
1. **[OPEN ENDED RESPONSE]**

C4. Based on your experience operating the EV/EV equipment, have you noticed an **improvement to your comfort or convenience**, such as better ride or vehicle/equipment performance compared to operating internal combustion engine vehicles or equipment?
1. Yes, I've **definitely** noticed this **[ASK C5]**
2. Yes, I've **somewhat** noticed this **[ASK C5]**
3. No, I have not noticed this

[ASK IF C4 = 1 OR 2]

C5. What comfort or convenience improvements have you observed?
1. **[OPEN ENDED RESPONSE]**

C6. Based on your experience operating the EV/EV equipment have you noticed a **reduction in noise** compared to operating internal combustion engine vehicles/equipment?
1. Yes, I've **definitely** noticed this **[ASK C7]**
2. Yes, I've **somewhat** noticed this **[ASK C7]**
3. No, I have not noticed this

[ASK IF C6 = 1 OR 2]

C7. Which noise reduction(s) have you observed?
1. **[OPEN ENDED RESPONSE]**

D. Challenges of Operating the EV/EV Equipment

The following questions pertain to any challenges you have experienced operating the EV/EV equipment compared to internal combustion engine vehicle/equipment and using the associated charging stations.

D1. Have you experienced any challenges operating the EV/EV equipment?
1. Yes **[ASK D2]**
2. No

[ASK IF D1 = YES]

D2. What kind of challenges have you experienced?
1. Difficult to find charging stations
2. Insufficient vehicle/equipment range
3. Requires charging more frequently than I expected
4. Is more challenging to drive/operate
5. Is unreliable or requires more maintenance than I expected
6. Other **[OPEN ENDED]**

D3. Are the current charging stations sufficient for the EV/EV equipment you operate?

1. Yes
2. No **[ASK D4]**

[ASK IF D3 = NO]

D4. In what ways are the EV charging stations lacking?

1. Difficult to find
2. Not enough charging stations
3. Difficult to use/operate the charging stations
4. Charging stations are located out of my way
5. Charging stations take longer to charge the EV/EV equipment than I expected
6. Charging stations are unreliable or require more maintenance than I expected
7. Other **[WITH WRITE IN OPTION]**

D5. How has your job changed now that you are driving an EV? Select all that apply. **[RANDOMIZE 1-8]**

1. More training requirements
2. More concern over range
3. Quieter ride/operation
4. Better driving experience
5. Less air pollution
6. Better towing capability
7. Improved job satisfaction/enjoyment, please specify how: _____ **[WITH WRITE IN OPTION]**
8. Nothing; my job has remained the same
9. Other **[WITH WRITE IN OPTION]**

E. Closing

E1. Do you have any other comments or questions for **[UTILITY NAME]** at this time? Please feel free to share any feedback you have about operating or charging the EVs/EV equipment, whether positive or negative.

1. **[OPEN ENDED RESPONSE]**

Those are all the questions we have. Thank you for your time.

CADMUS

SRP Evaluation: MDHD Fleet Withdrawal Interview Guide, EY2025

This interview seeks to learn more from program applicants (site hosts, fleet managers, or other relevant staff) who ended or indefinitely paused their participation in the California Standard Review Projects to electrify Medium-Duty and/or Heavy-Duty (MDHD) fleet vehicles. Questions in this interview guide seek to understand applicants' experience with the program, including their initial interest and factors that contributed to ending or pausing participation. Additionally, this survey seeks to understand the applicants' perspective on the EV market overall, as well as their fleet readiness for electrification. This interview is designed to take approximately 30 minutes and be administered via telephone.

Research Objectives	Corresponding Question Numbers
1. Identify the factors that facilitate successful fleet electrification and lessons learned	
Why did the applicant decide to pursue electrification initially? What benefits did applicants think they might gain from electrifying?	B1
How satisfied were applicants with the program overall? How does overall satisfaction vary by market segment?	B3-B10
Would applicants who withdrew from the program say that the program provides appropriate financial and non-financial support?	2-C2
Why did applicants decide to drop out of the program?	D1
What factors would have facilitated applicant participation in the program, if any?	D3
What would applicants have done differently, if anything?	D4-D5
What did applicants do instead of pursuing fleet electrification through the program?	C4-C8

Additional questions for funnel analysis:

- B2: How did you first hear about the IOU programs?
- B4: Summarize your path during the application and contract signing?
- D1: What precisely made you drop out?
- D2: How far along were you when you dropped out?
- C3: Did you pursue alternative funding paths (e.g., Rule 29, EnergIIZE, federal funds)?
- D3: Are there program changes that would have made you more likely to stay in the program?

Target Audience: Utility customers who submitted an application and subsequently withdrew from the program. This excludes applicants who were deemed ineligible for the program.

Desired number of completions: 10 total interviews, pending available sample; at least one for each utility

Estimated timeline for fielding: To be conducted in Q1 2026 for all withdrawn sites from EY2025.

Variables to be Pulled into Interview

- **Email**
- **FirstName**
- **LastName**

- **UTILITY (SCE, SDG&E, PG&E; read-in)**
- **PROGRAM_NAME (read-in; does not include "program" i.e., "EV Fleet" for PG&E)**
- **Organization**

Email Invitation

To: [EMAIL]
From: [Cadmus]
CC: [SCE/SDG&E/PG&E MDHD PM and Customer Account Manager]
Subject: Interview Regarding Your Experience with the [SCE/SDGE&E/PG&E] [PROGRAM_NAME] Program

Dear [FIRSTNAME AND LASTNAME],

Thank you for applying to the [SCE/SDG&E/PG&E] [PROGRAM_NAME] program. Our records indicate you did not complete an EV charging project as a part of [PROGRAM_NAME] program. We would like to conduct an interview with you to gather your feedback about how to improve the program experience for fleets in the future. Your input is very important to us and will be kept confidential and only used for research purposes. **The interview will take approximately 30 minutes to complete via telephone**.

To schedule an interview:

Navigate to our Microsoft Bookings page here.
Select one of the four available interview services to find a date and time that works best with your availability.
Note: If the first interviewer does not have available that matches yours, please check each of the four availability services. All services pertain to the California Medium- and Heavy-Duty Fleet Electrification Program interview opportunity.
Fill in your information and select "Book."

Once you have booked a time slot, you will receive an email from Microsoft with details. Please reach out to [redacted] at The Cadmus Group, the national research firm conducting this interview on the utility's behalf, with any inquiries or if you encounter any difficulties. [redacted] may be reached at ([redacted]) [redacted]-[redacted] or [redacted]@cadmusgroup.com.

Thank you in advance for sharing your experiences and your time.

CADMUS PERSON'S FIRST AND LAST NAME
THEIR TITLE
CADMUS GROUP

Initial Call Script

[IF CALL ANSWERED] Hello, this is **[caller name]** calling on behalf of The Cadmus Group to gather insights from **[SCE/SDG&E/PG&E] [PROGRAM_NAME]** applicants. Our records indicate that you participated in the **[SCE/SDG&E/PG&E] [PROGRAM_NAME]** and would like to schedule an informational interview. Your identifying information will remain confidential with Cadmus and **[UTILITY]**.

We understand your time is valuable, therefore we only ask for approximately 30 minutes of your time for a phone interview. Are you available to schedule an interview within the coming weeks?

- **[IF MOVING FORWARD WITH SCHEDULING]** Great, we appreciate your interest! Our informational interviews are scheduled with members of our research team. We have the following time slots available: **[USE BOOKINGS PAGE TO SCHEDULE].**

  [CONFIRM DATE SELECTED] Thank you, we look forward to your participation. You may expect **[explain follow-up steps]** **[UPDATE TRACKER]**.
- **[IF SCHEDULING IS NOT CONVINIENT]** Great, we appreciate your interest! Our informational interviews may be scheduled using our Microsoft Bookings page. Is **[CONFIRM EMAIL]** a good email for sharing the Bookings page? Thank you – please expect an email within the next 24 hours, and feel free to reach out with any questions.
- **[IF INTERVIEW DECLINED]** Not a problem, thank you for your time. **[UPDATE TRACKER]**

[IF CALL NOT ANSWERED, LEAVE MESSAGE] Hello, this is **[caller name]** calling on behalf of The Cadmus Group to gather insights from **[SCE/SDG&E/PG&E]** **[PROGRAM_NAME]** applicants. Our records indicate that you participated in the **[SCE/SDG&E/PG&E]** **[PROGRAM_NAME]** and would like to schedule an informational interview. We value your feedback and would like to schedule a 30-minute informational phone interview; please call me back at [contact info]. Alternatively, you should have received an email from a Cadmus team member with a Microsoft Bookings link that may be used to schedule the interview. Thank you for your time.

Follow-Up Call Scripts

Hello, this is **[caller name]** following up on behalf of The Cadmus Group to gather insights from **[SCE/SDG&E/PG&E]** **[PROGRAM_NAME]** applicants. We value your feedback and would like to schedule a 30-minute informational phone interview. Would you be available to schedule an interview?

- **[IF MOVING FORWARD WITH SCHEDULING]** Great, we appreciate your interest! Our informational interviews are scheduled with members of our research team. We have the following time slots available: **[USE BOOKINGS PAGE TO SCHEDULE]** **[UPDATE TRACKER].**

  [CONFIRM DATE SELECTED] Thank you, we look forward to your participation. You may expect **[explain follow-up steps]** **[UPDATE TRACKER]**.
- **[IF SCHEDULING IS NOT CONVINIENT]** Great, we appreciate your interest! Our informational interviews may be scheduled using our Microsoft Bookings page. Is **[CONFIRM EMAIL]** a good email for sharing the Bookings page? Thank you – please expect an email within the next 24 hours, and feel free to reach out with any questions. **[UPDATE TRACKER]**
- **[IF INTERVIEW DECLINED]** Not a problem, thank you for your time. **[UPDATE TRACKER]**

Interview Introductions

Thank you for taking the time to share your experience with the **[PROGRAM_NAME]** program, offered by **[UTILITY]**. For this study, Cadmus is conducting interviews with program applicants who ended or indefinitely paused their participation in the California Standard Review Projects to electrify Medium-Duty and/or Heavy-Duty (MDHD) fleet vehicles.

The purpose of these interviews is to understand your experience with the program, including your initial interest and factors which may have contributed to ending or pausing your participation. We also seek to understand applicants' overall perspective on the EV market, as well as their fleet readiness for electrification.

This interview will take approximately 30 minutes to complete, and your identifying information will remain confidential.

A. Overview & Background Information

First, we will begin with some general background questions to understand your fleet.

A1. **[IF INTERVIEWEE DATA IS AVAILABLE]** Our data indicates that your fleet includes **[name types of vehicles/equipment]**, can you confirm that this information is accurate?
   1. **[IF INTERVIEWEE DATA IS NOT AVAILABLE]** What types of vehicles or equipment do you have in your fleet?
      [INTERVIEWER NOTE: Refer to *Section E Table 1* to match responses with survey categories]

A2. For each type of vehicle and/or equipment you mentioned, please specify the number of internal combustion engine vehicles in your fleet, and the number of electric vehicles in your fleet.
[INTERVIEWER NOTE: Record the # of ICE vehicles and # of EVs for each vehicle type]

A3. We wish to understand how the **[PROGRAM_NAME]** program may have influenced your decision to electrify your fleet. Of the internal combustion engine vehicles in your fleet, **how many did you originally plan to electrify through the program**?
   1. How many did you originally plan to electrify **outside of the [PROGRAM_NAME] program**?

A4. Of the vehicles that you originally planned to electrify when you applied to the **[PROGRAM_NAME]** program, **how many have you electrified to date**? Please specify the number of vehicles per type.

A5. Are there any other vehicles that we have not discussed which you planned to electrify?
   1. **[IF YES]** Could you specify the vehicle/equipment type, the number of vehicles, and the rough timeframe for electrification?

B. Program Experience

Now we wish to understand your interest and experience specifically with the **[PROGRAM_NAME]** program.

B1. Could you describe the reasons why your fleet initially intended to transition to EVs? ***(Probe: regulatory requirements, expected savings, environmental benefits, etc.)***

[INTERVIEWER NOTE: Refer to Section E Table 2 to match responses with survey categories]

B2. How did you first hear about the **[PROGRAM_NAME]** program?

B3. We'd like to start by hearing about your overall experience. How satisfied were you with the **[PROGRAM_NAME]** program **overall**? Please use a scale from 1 to 4, where 1 means *not at all satisfied* and 4 means *very satisfied*.

1. Why did you give that specific rating?

B4. Could you summarize your path through the **application process** and contract signing for the **[PROGRAM_NAME]** program?

1. How satisfied were you with the **application process**? Please use the same scale from 1 to 4, where 1 means *not at all satisfied* and 4 means *very satisfied*.

B5. How satisfied were you with the **application timeline** for the **[PROGRAM_NAME]** program?

1. Why did you give that specific rating?

B6. We would like to know about your experience with the **level of program services** offered as a part of the **[PROGRAM_NAME]** program, such as site planning or provision of to-the-meter infrastructure. First, were you **aware of the services offered** as part of the program?

1. **[IF YES]** Similar to the previous questions, how satisfied were you with the **level of program services? [IF NEEDED:** Please use the same scale from 1 to 4, where 1 means *not at all satisfied* and 4 means *very satisfied*.**]**

B7. Now we turn to the **amount of eligible rebates offered** from **[UTILITY]** as part of the **[PROGRAM_NAME]**. Were you **aware of the amount of the eligible rebates offered** (i.e., the $ value) as part of the program?

1. **[IF YES]** How satisfied were you with the **amount of the eligible rebates offered** as part of the program? **[IF NEEDED:** Please use the same scale from 1 to 4, where 1 means *not at all satisfied* and 4 means *very satisfied*.**]**
2. **[ASK IF B7.1=1 NOT TOO SATISFIED OR 2 NOT AT ALL SATISFIED]** What **amount of rebate** would have made you more satisfied?
3. **[ASK IF B7.1=1 NOT TOO SATISFIED OR 2 NOT AT ALL SATISFIED]** If this rebate level were offered, would it have **changed your likelihood to participate** in the **[PROGRAM_NAME]** program? **How much more would it have changed your likelihood**?

B8. Lastly, on a scale from 1 to 4, with 1 being not at all satisfied and 4 being very satisfied, how satisfied were you with your **experience working with [UTILITY] staff**?

The last two questions for this section pertain to your opinion on services and rebates that you believe the **[PROGRAM_NAME]** program should offer.

B9. What **kinds or levels of services** should the **[PROGRAM_NAME]** program offer?

[INTERVIEWER NOTE: Refer to *Section E Table 3* to match responses with survey categories]

B10. What **types of costs** should the **[PROGRAM_NAME]** program rebates cover?

[INTERVIEWER NOTE: Refer to *Section E Table 4* to match responses with survey categories]

C. Actions Outside of the Program and Nonparticipant Spillover

The next series of questions will ask about actions that you may have taken outside of your participation in the **[PROGRAM_NAME]** program.

C1. Did you install any EV charging equipment without the rebates offered from **[UTILITY]** as a part of the **[PROGRAM_NAME]** program?
1. Yes **[ASK C2]**
2. No

C2. **[ASK IF C1=YES]** Did you receive any rebates or incentives to cover some of the cost of the EV charging equipment? If so, please specify where the rebates or incentives came from.

C3. **[ASK IF C1=YES]** Did you pursue any alternative funding when you dropped out of the program, such as Rule 29, EnergIIZE, or federal funds?

C4. Which of the following best describes how your organization proceeded with electrification after deciding not to participate in the **[PROGRAM_NAME]** program?
1. Built project as intended
2. Built project scaled down from intended plan:
   (a) What was different from the intended plan? **[OPEN ENDED]**
3. Decided not to incorporate EVs into the fleet
4. Put project on temporary hold **[ASK C8]**
5. Built project through utility's general distribution service planning program (Rule 28/29/45)
6. Other, please specify: **[OPEN ENDED]** **[INTERVIEWER NOTE: Try to avoid using this answer option if possible.]**

C5. **[ASK IF C4=1, 2, OR 5]** When was this project completed? Please specify the month and year.
1. **[OPEN ENDED]**
2. Not completed yet; please specify the expected completion date: **[OPEN ENDED]**

C6. **[ASK IF C4=1, 2, OR 5]** What were the specifics of the project, such as the number of vehicles by type and number of chargers?
1. **[OPEN ENDED]**

C7. **[ASK IF C4=1, 2, OR 5]** How important was your experience with the **[PROGRAM_NAME]** program on your decision to build EV charging infrastructure outside of the **[PROGRAM_NAME]** program? Please use a scale from 0 to 10, where 0 is "not at all important" and 10 is "extremely important".

1. **[RECORD RATING 0-10]**

[ASK IF C4=4]

C8. If project is on temporary hold, which of the following best represents its current status?

1. Pending funding from a specific source (or sources), please specify: **[OPEN ENDED]**
2. Pending further action from the utility, please specify: **[OPEN ENDED]**
3. Pending procurement or delivery of electric vehicles or equipment, please specify: **[OPEN ENDED]**
4. Pending procurement or delivery of EV charging equipment, please specify: **[OPEN ENDED]**
5. Pending for some other reason, please specify: **[OPEN ENDED]**

C9. **[ASK IF C1=YES]** Did discussions with other fleets influence your decision to electrify some fleet vehicles? **[IF YES]** Please describe how these discussions influenced your decision.

D. Reasons for Dropping Out of the Program

Next, we would like to explore why you decided to end your participation in the **[PROGRAM_NAME]** program.

D1. What were the main reasons why your organization decided to stop participating in the program? ***(Probe: costs, labor, equipment availability, etc.)***

[INTERVIEWER NOTE: Refer to Section E Table 5 to match responses with survey categories]

D2. What step were you at in the **[PROGRAM_NAME]** program when you decided to drop out?

D3. What factors would have enabled your continued participation in the program, if any? ***(Probe: lower costs, greater knowledge and process support, etc.)***

[INTERVIEWER NOTE: Refer to *Section E Table 6* to match responses with survey categories]

D4. Based on your experience with fleet electrification so far, what would you recommend to other utility customers who may be going through this process or considering it?

D5. What, if anything, would you recommend **[UTILITY]** change about the program to improve it?

End of Interview Message

Those are all the questions we have. Thank you for your time.

E. Reference categories from original survey questions

Table 1, Question A1. Types of potential vehicles/equipment in fleet.

1. School bus
2. Transit bus
3. Medium-duty vehicles
4. Heavy-duty vehicles
5. Port cargo trucks
6. Airport ground support equipment
7. Forklifts
8. Truck refrigeration unit
9. Truck stop electrification technology
10. Other

Table 2, Question B1. Potential reasons for transitioning vehicle fleet to EVs

1. Regulatory requirement
2. Corporate/organizational sustainability goals or initiatives
3. Expected fuel cost savings
4. Expected maintenance cost savings
5. Better technology
6. Driver comfort/preference
7. Environmental benefits
8. Rebates/incentives for EVs
9. Rebates/incentives for EV charging infrastructure
10. Other

Table 3, Question B11. Kinds or levels of services that [**PROGRAM_NAME**] program should offer.

1. Increased technical support on electric vehicles
2. Increased technical support on EV charging equipment
3. Increased utility-side make-ready infrastructure support
4. Increased customer-side make-ready infrastructure support
5. Other

Table 4, Question B12. Types of costs that [**PROGRAM_NAME**] rebates should apply to.

1. Construction costs
2. EVSE costs
3. Vehicle costs
4. Other

Table 5, Question D1. Reasons for ending participation in the [**PROGRAM_NAME**] program.

1. Vehicle costs
2. Charging equipment costs
3. Behind-the-meter make-ready costs
4. Inability to obtain easements
5. Difficulty hiring contractors to install the behind-the-meter infrastructure or EV chargers
6. Labor costs
7. Lack of availability of electric vehicles/equipment that met my fleet's needs
8. Inadequate incentives
9. Lack of utility support for behind-the-meter make-ready process
10. Required too much time
11. Training requirements
12. Driver hesitancy
13. Reliability concerns with EVs or EV chargers
14. Return-on-investment was too long
15. Timeline to receive vehicles is too long
16. Other organizational priorities for funds/other stakeholder input
17. Other

Table 6, Question D3. Factors that would have enabled continued participation in the program.

1. Lower costs of or higher rebates for charging infrastructure
2. More utility support for behind-the-meter make-ready process
3. More knowledge sharing with other fleet managers electrifying their fleets
4. Ability to obtain easement
5. Lower costs of or more funding for the electric vehicles/equipment
6. More availability of electric vehicles/equipment that meet my fleet's needs
7. Greater interest from drivers
8. Greater interest from other organizational stakeholders or decisionmakers
9. Other