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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006

COMPLIANCE FILING OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND PACIFIC GAS AND ELECTRIC COMPANY (U 93 E) PURSUANT TO ORDERING PARAGRAPH 2 OF DECISION 16-06-011

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Dated: March 31, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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COMPLIANCE FILING OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND PACIFIC GAS AND ELECTRIC COMPANY (U 93 E) PURSUANT TO ORDERING PARAGRAPH 2 OF DECISION 16-06-011

Southern California Edison Company ("SCE"), San Diego Gas & Electric Company ("SDG&E") and Pacific Gas and Electric Company ("PG&E") hereby file[1] their Electric Vehicle Charging Infrastructure Cost Report as required by Decision (D.) 16-06-011 and the Administrative Law Judge Ruling Amending the Load Research Report Deadline for 2020 and Beyond issued on January 6, 2020.[2] The report is attached to this pleading.

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[1] Pursuant to Commission Rule 1.8(d), SCE and SDG&E have authorized PG&E to file the attached compliance report on their behalf.

[2] D.16-06-011 issued in Rulemaking (R.) 13-11-007. R.18-12-006 (at 1) states that it is the "successor proceeding" to R.13-11-007. R.18-12-006, Assigned Comm'r's Scoping Memo and Ruling (May 2, 2019) at 18, ¶ 9, directs the respondent utilities to continue filing the subject reports as provided by D.16-06- 011. The Administrative Law Judge's Ruling Amending Load Research Report Deadline for 2020 and Beyond (January 6, 2020) at 3, directs filing the reports "on March 31 of the given reporting year" going forward. Based on guidance from Commission Energy Division, the title of the attached report has been changed from the "Load Research Report" used in earlier reports.

Respectfully submitted,

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March 31, 2022

ATTACHMENT

Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report 10th Report Filed on March 31, 2022

Table of Contents

I. Executive Summary

The Joint Investor-Owned Utility (IOU) Electric Vehicle (EV) Load Research and Charging Infrastructure Cost Report for 2021 (Report) examines EV customer charging behavior and service and distribution system upgrade costs related to EV load for California's three large investor-owned utilities (IOUs), including Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), collectively the Joint IOUs. In this report, the Joint IOUs provide EV load and infrastructure costs by (1) pilot-programs and (2) rates or non-programs. An examination of EV charging behavior and EV charging infrastructure costs within the Joint IOUs' territories can provide useful insights on the IOUs' support in helping accelerate widespread transportation electrification (TE).

To help attain its climate and air quality goals, California has set correspondingly aggressive TE goals, as the transportation sector is the largest source of Greenhouse Gas (GHG) emissions in the state.[1] Senate Bill (SB) 350 established that "[a]dvanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse gas emissions reduction goals,"[2] and required the Commission to direct electrical corporations to file applications for programs and investments to accelerate widespread TE.[3]

California's aggressive TE goals include Governor Brown's Executive Order (E.O.) B-48-18, which sets a target of five million zero emission vehicles (ZEVs) on California's roads by 2030 and requires installation of 250,000 public charging stations, including 10,000 direct current fast charging stations in operation by 2025. Additionally, on September 23, 2020, Governor Gavin Newsom issued Executive Order (E.O.) N-79-20, requiring the sale of all new passenger vehicles to be zero emission by 2035 and, where possible, directs all medium- and heavy-duty vehicles to be zero emission by 2045.

The IOUs have and will continue to play a critical role in TE infrastructure deployment through the IOUs' core business of delivering electricity, supporting the installation of utility-side infrastructure for EV charging, and in the development and implementation of strategically designed rate-payer funded pilots and programs that support the acceleration of TE.

A. IOU EV Adoption Forecasts

The EV market is evolving. New vehicle models with larger battery sizes, supporting increased charging levels and more choices for charging equipment, and charging services are entering

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[1] CARB, *California Greenhouse Gas Emissions for 2000 to 2018: Trends of Emissions and Other Indicators* (2020 Edition), p. 5.
https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2018/ghg_inventory_trends_00-18.pdf

[2] PU Code, § 740.12 (a)(1)(A).

[3] PU Code, § 740.12 (a)(1)(I)(2)(b).

the EV market. Some EV manufacturers and charging providers have also left the market. This product and service evolution will affect vehicle adoption, charging demand, and infrastructure costs and is expected to continue in the near term as the EV market grows and matures.

As of December 31, 2021, the IOUs estimate that more than 735,348 EVs were on the roads in their service territories. The number of light duty and medium- and heavy-duty EVs forecast to be operating in the IOUs service territories from 2022 through 2027 are provided in Table 1.

TABLE 1: IOU EV ADOPTION FORECASTS

	Light Duty EVs			**Medium- and Heavy-Duty EVs**		
Year	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
2022	446,901	398,801	57,820	1,203	1,895	N/A
2023	557,942	500,847	64,436	1,570	3,495	N/A
2024	700,472	628,491	71,051	2,278	5,974	N/A
2025	883,644	741,619	77,667	3,544	9,412	N/A
2026	1,125,451	875,111	84,283	5,718	13,787	N/A
2027	1,428,018	1,061,315	90,899	9,234	18,977	N/A

Each IOU may use a different methodology to forecast EVs in their service territory. Details on the methodology, as well as an expanded forecast, can be found in Table 1 of each IOUs' attachments submitted in conjunction with this report.

B. Revised IOU EV Load Research and Charging Infrastructure Cost Report

Since 2011, the IOUs have filed annual Load Research Reports focused on residential EV customer charging behavior and service distribution system upgrade costs related to residential EV load. On December 19, 2018, the California Public Utilities Commission (Commission or CPUC) issued Rulemaking (R.) 18-12-006, the Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification (DRIVE OIR). Within the DRIVE OIR, Energy Division staff were directed to consider "whether Load Research Reports include all relevant data and whether or how to direct the IOUs to continue filing Load Research Reports."[4] Additionally, the IOUs were directed to "incorporate cost data related to infrastructure needed to upgrade commercial customer sites where ZEVs (zero emission

[4] R.18-12-006, Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007, December 19, 2018, p. 15.

vehicles) are being deployed" into the Load Research Report.[5] To address these requirements, in 2019, the IOUs collaborated with the Energy Division staff to revise the Load Research Report. The renamed IOU EV Charging Infrastructure Cost Report eliminated load data, adopted a standard template for program and non-program infrastructure costs, and incorporated commercial upgrade costs.

In 2020, the Energy Division directed the IOUs to incorporate load data back into this Report. The 2020 Report included data for residential and commercial EV load, project cost, service line and distribution system upgrades, and the current EV adoption forecasts of each IOU, all of which are discussed in further detail in the following sections. This report similarly includes this data for January 2021 through December 2021.

The IOUs will continue to work closely with Energy Division to adjust the content and format of future reports as necessary based on feedback.

II. Background

On July 25, 2011, the Commission issued Decision (D.)11-07-029 (the Phase 2 Decision) in the Alternative-Fueled Vehicle Order Instituting Rulemaking (R.) 09-08-009 (AFV OIR), to evaluate policies and develop infrastructure sufficient to overcome barriers for the deployment and use of EVs in California. The Phase 2 Decision of the AFV OIR determined that EV load is new and permanent under Electric Rules 15 and 16 and adopted the interim policy of treating the residential EV charging costs that exceed the allowances in Rules 15 and 16 as common facility costs. The Phase 2 Decision also ordered California's IOUs, which includes PG&E, SDG&E, and SCE, to conduct research to examine EV customer charging behavior, as well as track service and distribution system upgrade costs related to EV load. The IOUs filed the first Joint IOU Electric Vehicle Load Research Report (Load Research Report) in December 2012. In D.13-06-014, issued July 3, 2013 (the First Extension Decision), the Commission extended the research for an additional three years[6] with reports to begin in December 2013.[7] The First Extension Decision also directed the Energy Division to work with stakeholders to revise the load research methodology.[8] In D.16-06-011, issued on June 13, 2016 (the Second Extension Decision), the Commission extended the interim policy of treating the residential electric vehicle charging costs that exceed the allowances in the Electric Rules 15 and 16 of the three IOUs as common

[5] Assigned Commissioner's Scoping Memo and Ruling, p. 13.
[6] D.13-06-014, p. 15.
[7] D.13-06-014, Ordering Paragraph 4.
[8] D.13-06-014, Ordering Paragraph 3.

facility costs for another three years, to June 30, 2019.[9] In addition, the annual filing requirement of the Load Research Reports was extended by another three years.

On December 19, 2018, the Commission issued the DRIVE OIR (R.18-12-006) and directed the Energy Division staff to consider "whether Load Research Reports include all relevant data and whether or how to direct the IOUs to continue filing Load Research Reports."[10] The subsequent Scoping Memo, issued May 2, 2019, directed the IOUs to incorporate cost data related to EV infrastructure upgrades for commercial customer sites in the 2020 report and extended the interim treatment for Electric Rules 15 and 16 allowances to December 31, 2019.[11] An ALJ Ruling as part of R.18-12-006 extended the interim treatment policy once again to December 31, 2021.[12] On November 5, 2019, the IOUs sent a letter to CPUC Executive Director requesting permission to delay the filing of the 2020 report from January 31, 2020 to March 31, 2020 and to adjust the content of the report. On January 6, 2020, the Administrative Law Judge (ALJ) issued a Ruling Amending the Load Research Report Deadline for 2020 and Beyond.[13] The ALJ Ruling established March 31 as the filing deadline for the 2020 report and any subsequent Electric Vehicle Load Research Reports.[14]

III. Load Research and Customer Behavior on Rates in Various Settings

A. Overview and Approach

This report provides residential and commercial EV load from January 2021 through December 2021 by (1) rate and (2) pilot-programs. The report reflects Commission requirements, including the Phase 2 Decision directive that the IOUs:

1. Track and quantify all new load and associated upgrade costs in a manner that allows EV load and related costs to be broken out and specifically identified. This information shall be collected and stored in an accessible format useful to the Commission.

[9] D.16-06-011, Ordering Paragraph 2.

[10] R.18-12-006, Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007, December 19, 2018, p. 15.

[11] R.18-12-006, Assigned Commissioner's Scoping Memo and Ruling, May 2, 2019, p. 18.

[12] R.18-12-006, ALJ E-mail Ruling Extending Interim Policy on Common Facility Costs, issued on November 23, 2020.

[13] R.18-12-006, Administrative Law Judge's Ruling Amending Load Research Report Deadline for 2020 and Beyond, January 6, 2020, p.3. The ALJ Ruling approves filing the report on March 31 of the given reporting year going forward.

[14] ALJ Ruling, p. 1.

2. Evaluate how metering arrangements and rate design impact Plug-in electric Vehicle (PEV) charging behavior.

3. To the extent relevant, determine whether participation in demand response programs impacts EV charging behavior.

4. Determine how charging arrangements, including metering options and alternative rate schedules impact charging behavior at Multi-Dwelling Units (MDU)."[15]

This metering data provides the basis for analyzing how charging behavior is impacted by tariff rates or charging levels. Additionally, the recorded data allowed for the evaluation of metering scenarios on PEV charging behavior for customers in the following residential categories:[16]

- Single Family Home (SF)
- Multi Family Dwelling Unit (MDU)
- Net Energy Metering (NEM)

Distinctions between single metering and separate metering are shown, as well as NEM participation. The usage and demand of customers were tracked in each rate group. The goal of this structure was to determine how monthly usage varies, how rates impact peak demand and how usage varies by time-of-use rate among different groups of customers. A baseline for residential customers has been analyzed for context in the form of an average for a month during the season being examined.

To the extent possible, the IOUs provided similar information for easy comparisons. However, there are some cases where this is simply not possible due to differences in the underlying IOU data. Metrics with less than 15 customers are clearly noted and not reported without prior notice due to confidentiality concerns described in the 15/15 Rule adopted by the Commission in Decision 97-10-031 and Decision 14-05-016. All time periods are reported in 24-hour time. SCE's load profiles are reported in Pacific Standard Time while PG&E and SDG&E are provided in prevailing time. Time-of-use periods vary across the IOUs and will be explicitly defined within each IOU section.

[15] D.11-07-029, Ordering Paragraph 6.

[16] The MDU and SF categories are mutually exclusive. However, the other categories can overlap. For example, a NEM customer that is also on DR would appear in three categories.

B. PG&E’s Load and Customer Behavior Data

Load and utilization across PG&E’s EV-specific rates and a portion of the Transportation Electrification Programs are reported in the following sections. The study period covers the full calendar year of 2021. PG&E’s rates during the study period included residential and commercial products. The residential rates reported include PG&E’s Single-Metered Rates (EV-A and EV2-A) and a Separately-Metered Rate (EV-B). However, EV-A was closed to new enrollments with the introduction of EV2-A in July 2019 and most customers were fully transitioned to the EV2-A rate by the end of 2019. The load data for single-metered residential customers in 2021 reflects both EV-A and EV2-A customers.

PG&E launched the BEV-1 and BEV-2 rates in May 2020, for commercial customers. Load data for both rates is reported for the 2021 calendar year. Additionally, utilization and load data for light duty infrastructure and medium duty/heavy duty infrastructure installed as part of PG&E’s Transportation Electrification Programs is reported for the 2021 calendar year. Principally, utilization is from charging infrastructure installed as part of the Electric Vehicle Charge Network (EVCN) program and the EV Fleet Program. Finally, the 2020 Infrastructure Cost and Load Research report referenced utilization data from Evaluation Reports for each of PG&E’s three Priority Review Projects (PRPs). For PRP utilization data in 2021, please reference the SB 350 PRP annual data report directly – submitted separately, to be filed in June 2022.

A note to be aware of is the continued impact COVID-19 and shelter-in-place orders may have had on EV driving and charging behavior throughout the 2021 calendar year. Ultimately, 2021 proved to be a year with continued impacts from COVID-19 that may have affected traditional expectations from rate price signals and time-of-use structures.

Residential PEV Rates

Single-Metered and Separately-Metered PEV Residential Rates

As of the date of this report, PG&E has two residential EV rates open to customers, one for single-metered customers (EV2-A) and another for separately-metered customers (EV-B). A previous version of the single-metered rate was closed to new customers in July 2019. The single-metered rate is a residential whole home rate that applies to both typical household electric load and electric vehicle charging on the same meter. The separately-metered rate is designed for customers who wish to bill their vehicle charging separately and requires the installation of a separate meter to do so. Both rate plans use an un-tiered TOU rate structure. They offer on-peak, partial peak, and off-peak energy prices according to the time periods in Table PG&E-1. Regardless of season, or day of the week, both rates seek to encourage usage in off-peak hours. The single-metered rate includes off-peak hours from 12:00 a.m. to 3:00 p.m., and the separately-metered rate from 11:00 p.m. to 7:00 a.m. The separately-metered rate further encourages weekend usage by limiting peak periods to 3:00 p.m. to 7:00 p.m. and expanding the “off-peak” period to all other remaining hours on weekends and holidays.

Table PG&E-1: Tariff Type and Rate ($/kWh) in 2021

Rate: EVA

Hour	Winter Weekday	Winter Weekend / Holidays	Summer Weekday	Summer Weekend / Holidays
12mn - 1am	0.14909	0.14909	0.14568	0.14568
1am - 2am	0.14909	0.14909	0.14568	0.14568
2am - 3am	0.14909	0.14909	0.14568	0.14568
3am - 4am	0.14909	0.14909	0.14568	0.14568
4am - 5am	0.14909	0.14909	0.14568	0.14568
5am - 6am	0.14909	0.14909	0.14568	0.14568
6am - 7am	0.14909	0.14909	0.14568	0.14568
7am - 8am	0.25072	0.14909	0.31010	0.14568
8am - 9am	0.25072	0.14909	0.31010	0.14568
9am - 10am	0.25072	0.14909	0.31010	0.14568
10am - 11am	0.25072	0.14909	0.31010	0.14568
11am - 12nn	0.25072	0.14909	0.31010	0.14568
12nn - 1pm	0.25072	0.14909	0.31010	0.14568
1pm - 2pm	0.25072	0.14909	0.31010	0.14568
2pm - 3pm	0.41268	0.14909	0.56624	0.14568
3pm - 4pm	0.41268	0.41268	0.56624	0.56624
4pm - 5pm	0.41268	0.41268	0.56624	0.56624
5pm - 6pm	0.41268	0.41268	0.56624	0.56624
6pm - 7pm	0.41268	0.41268	0.56624	0.56624
7pm - 8pm	0.41268	0.14909	0.56624	0.14568
8pm - 9pm	0.41268	0.14909	0.56624	0.14568
9pm - 10pm	0.25072	0.14909	0.31010	0.14568
10pm - 11pm	0.25072	0.14909	0.31010	0.14568
11pm - 12mn	0.14909	0.14909	0.14568	0.14568

Rate: EV2A

Hour	Winter All days including Holidays	Summer All days including Holidays
12mn - 1am	0.18647	0.18647
1am - 2am	0.18647	0.18647
2am - 3am	0.18647	0.18647
3am - 4am	0.18647	0.18647
4am - 5am	0.18647	0.18647
5am - 6am	0.18647	0.18647
6am - 7am	0.18647	0.18647
7am - 8am	0.18647	0.18647
8am - 9am	0.18647	0.18647
9am - 10am	0.18647	0.18647
10am - 11am	0.18647	0.18647
11am - 12nn	0.18647	0.18647
12nn - 1pm	0.18647	0.18647
1pm - 2pm	0.18647	0.18647
2pm - 3pm	0.18647	0.18647
3pm - 4pm	0.35517	0.38849
4pm - 5pm	0.37187	0.49898
5pm - 6pm	0.37187	0.49898
6pm - 7pm	0.37187	0.49898
7pm - 8pm	0.37187	0.49898
8pm - 9pm	0.37187	0.49898
9pm - 10pm	0.35517	0.38849
10pm - 11pm	0.35517	0.38849
11pm - 12mn	0.35517	0.38849

Rate: EVB

Hour	Winter Weekday	Winter Weekend / Holidays	Summer Weekday	Summer Weekend / Holidays
12mn - 1am	0.14864	0.14864	0.14525	0.14525
1am - 2am	0.14864	0.14864	0.14525	0.14525
2am - 3am	0.14864	0.14864	0.14525	0.14525
3am - 4am	0.14864	0.14864	0.14525	0.14525
4am - 5am	0.14864	0.14864	0.14525	0.14525
5am - 6am	0.14864	0.14864	0.14525	0.14525
6am - 7am	0.14864	0.14864	0.14525	0.14525
7am - 8am	0.24754	0.14864	0.30710	0.14525
8am - 9am	0.24754	0.14864	0.30710	0.14525
9am - 10am	0.24754	0.14864	0.30710	0.14525
10am - 11am	0.24754	0.14864	0.30710	0.14525
11am - 12nn	0.24754	0.14864	0.30710	0.14525
12nn - 1pm	0.24754	0.14864	0.30710	0.14525
1pm - 2pm	0.24754	0.14864	0.30710	0.14525
2pm - 3pm	0.40631	0.14864	0.56025	0.14525
3pm - 4pm	0.40631	0.40631	0.56025	0.56025
4pm - 5pm	0.40631	0.40631	0.56025	0.56025
5pm - 6pm	0.40631	0.40631	0.56025	0.56025
6pm - 7pm	0.40631	0.40631	0.56025	0.56025
7pm - 8pm	0.40631	0.14864	0.56025	0.14525
8pm - 9pm	0.40631	0.14864	0.56025	0.14525
9pm - 10pm	0.24754	0.14864	0.30710	0.14525
10pm - 11pm	0.24754	0.14864	0.30710	0.14525
11pm - 12mn	0.14864	0.14864	0.14525	0.14525

Legend:

	Winter	Summer
On		
Part		
Off		

* While the table depicts 24-hour time, there is a daylight saving time adjustment as described in the tariff.

** Rates effective through December 31, 2021. For details see Electric Schedule EV, Residential Time-of-Use Service for Plug-in Electric Vehicle Customers, retrieved from https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_EV%20(Sch).pdf

These rates change seasonally, generally rising in summer and dropping in winter. Table PG&E-2 depicts price ratios for the TOU periods by season to illustrate this seasonal difference.

Table PG&E-2: Price Ratios for 2021

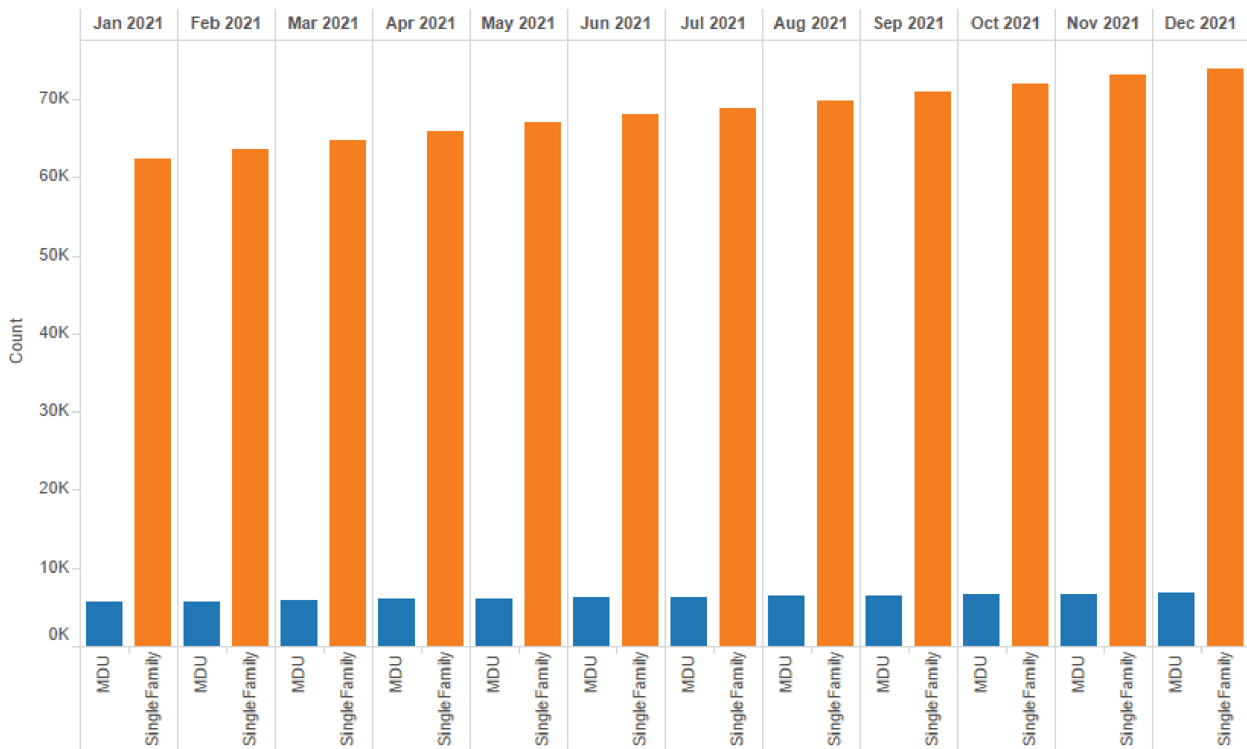
	EV-A		EV2-A		EV-B	
Season	Between Off-Peak and Partial Peak	Between Off-Peak and Peak	Between Off-Peak and Partial Peak	Between Off-Peak and Peak	Between Off-Peak and Partial Peak	Between Off-Peak and Peak
Winter	0.59	0.36	0.53	0.50	0.60	0.37
Summer	0.47	0.26	0.48	0.37	0.47	0.26

Single-Metered Rate Growth

Participation in the single-metered PEV rate showed a steady increase during 2021, the duration of the study period, as seen in Chart PG&E-1. Participation in the single-metered PEV rate showed a notable increase among Single Family (SF) customers while enrollment remained relatively steady among Multi-Dwelling Unit (MDU)[17] customers during 2021. It is important to note that not all EV customers have adopted PEV rates.[18] Of the customers on PEV rates, the majority are on the single-metered rate.

All Single-Metered Customers: Chart PG&E-1, below, displays the total customers on the single-metered PEV rate in 2021. During the study period, there was a notable increase in single-metered rate enrollment overall, primarily in the SF subcategories. The number of accounts in the single-metered group as a whole increased by 19% between January and December in 2021.

Chart PG&E-1: Single-Metered Accounts by Customer Type (2021)



NEM Single-Metered Customers: Net Energy Metering (NEM) customers on the PEV rates are an important group to consider. Of all the PG&E customers who were on the single-metered rate, up to 36% were also on NEM at any given time during the one-year study period. Virtually all dual PEV Rate/NEM customers were on the single-metered rate (see Table PG&E-3).

[17] Multi-dwelling units (MDUs) are defined as a residential unit with a shared wall (e.g. condo or townhouse) and are distinct from Multi-unit dwellings (MUDs) (e.g. apartment buildings), which is a term used in this report to refer to a Multi-Family Housing site that is part of a TE Program and could be enrolled in a commercial rate.

[18] The load research figures in this report only represent the number of PG&E PEV customers on PEV rates, not all PEV customers.

The fact that NEM customers with PEVs predominately use the single-metered rate presents a load research challenge. The presence of onsite distributed generation (DG) alongside a PEV behind these customers' meters indicates that their utility energy usage data does not reflect their gross consumption. This is because the DG will have offset some portion of consumption. However, without additional metering of the DG, it is not feasible to isolate the effect PEV ownership has on usage patterns for this group using utility metering data alone.[19]

Table PG&E-3: Single-Metered NEM Program Enrollment by Customer Type (2021)

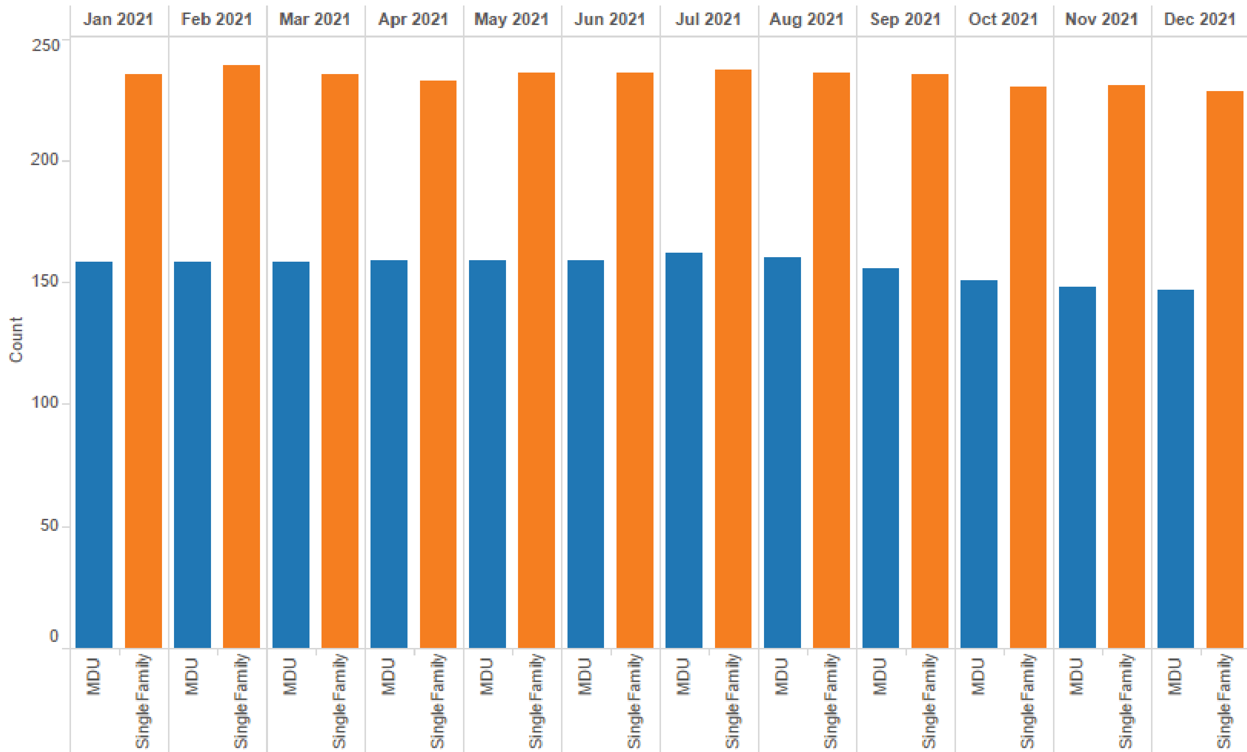
Year	Month	Number of All Single-Metered NEM Enrollments	NEM % of All Single-Metered	NEM % of SF Single-Metered	NEM % of MDU Single-Metered
2021	Jan	22,981	34%	35%	43%
2021	Feb	21,381	34%	36%	41%
2021	Mar	24,352	35%	36%	39%
2021	Apr	23,813	35%	37%	37%
2021	May	25,590	35%	37%	34%
2021	Jun	26,149	35%	37%	31%
2021	Jul	25,301	36%	37%	29%
2021	Aug	27,021	36%	37%	27%
2021	Sep	27,392	36%	37%	24%
2021	Oct	27,842	35%	37%	22%
2021	Nov	26,946	35%	37%	20%
2021	Dec	28,742	36%	38%	19%

Separately-Metered Rate Growth

All Separately-metered Customers: The separately-metered PEV rate remains a less popular option for PEV rate customers than the single-metered PEV rate. As shown in Chart PG&E-2, compared to the single-metered rate, there was lower participation and even a small decrease in enrollment between January and December 2021 (4%). While the installation of a separate meter for EV charging could be financially challenging for some customers, PG&E is exploring strategies to make the separately-metered rate more accessible to all customers.

[19]While there are numerous other demographic and behavioral attributes of this early PEV adopter group that affect usage, there was insufficient data or resources to isolate and identify their contribution to load shapes.

Chart PG&E-2: Separately-Metered Accounts by Customer Type (2021)



NEM Separately-Metered Customers: There were only a small number of PEV rate customers on the separately-metered PEV rate enrolled in NEM in 2021, and therefore the specific enrollment numbers cannot be shared publicly. As shown in Table PG&E-4, the number of separately-metered customers enrolled in NEM remained relatively flat during the study period. The single-metered PEV rate continues to be the more popular option for PEV customers wishing to offset their charging with DG.

Table PG&E-4: Separately-Metered NEM Program Enrollment by Customer Type (2021)

Year	Month	Number of Separately-metered NEM Enrollments	NEM % of Separately-metered	NEM % of SF Separately-metered	NEM % of MDU Separately-metered
2021	Jan	<100	>10%	>10%	>10%
2021	Feb	<100	>10%	>10%	>10%
2021	Mar	<100	>10%	>10%	>10%
2021	Apr	<100	>10%	>10%	>10%
2021	May	<100	>10%	>10%	>10%
2021	Jun	<100	>10%	>10%	>10%
2021	Jul	<100	>10%	>10%	>10%
2021	Aug	<100	>10%	>10%	>10%
2021	Sep	<100	>10%	>10%	>10%
2021	Oct	<100	>10%	>10%	>10%
2021	Nov	<100	>10%	>10%	>10%
2021	Dec	<100	>10%	>10%	>10%

Notes of Caution Regarding Reliance upon Load Research Data

The reader should take careful note of the following issues that make the load research data ill-suited for drawing conclusions for policymaking at this time.

- While PEV ownership has increased, it is still largely comprised of early adopters who are likely to be materially different than future PEV owners. These differences could include, but are not limited to, income, commuting patterns, pre-PEV ownership usage habits, NEM penetration, altruistic tendencies, and willingness/ability to adopt usage patterns beneficial to grid stability.
- The types of PEVs available in the market evolved through the year, suggesting that the types of PEVs owned by PEV rate customers would have changed during that same time frame. New vehicles and charging requirements may lead to changes in charging profiles in the future (i.e., differing charging demands and durations).
- The customer counts are slowly growing but were still relatively small in all cases. This is particularly true for separately-metered PEV rate data derived from PG&E's load research sample. The mix of customers being evaluated changed over time due to customers joining or leaving the single-metered or separately-metered PEV rates. The single-metered rate also transitioned from the EV-A rate, which closed to new enrollments in July of 2019, to the new EV2-A rate, which opened at the same time. Additionally, effective July 2019, all customers on an EV rate are subject to eligibility criteria based on usage. Customers who exceed 800% of their cumulative baseline after 12-months of usage are removed from the rate and placed on an alternative TOU rate.
- While PEV charging for the single-metered PEV rate may be fairly obvious if it takes place during off-peak rate periods when there is low electric consumption from other sources, the lack of on-site survey or end use data to help disaggregate other loads from

PEV charging prevents the identification of PEV charging in other periods (particularly partial-peak) where multiple significant loads are likely present.

Therefore, while the data collected are illustrative of the behaviors of early adopters based on the types of vehicles that are currently available in the market, one cannot conclude that these behavior patterns will hold as PEV technology matures, as charging technology and charging behaviors evolve, and as PEVs achieve greater market adoption beyond the early adopter phase. PG&E will continue to collect and report load data from residential EV rate customers via this report, but specific learnings to influence policy should be obtained via an appropriately funded and carefully designed study that controls for the above issues.

Average Monthly Usage for PEV Rate Customers

Keeping in mind the above cautions about the data collected, Chart PG&E-3 displays the average monthly usage for single-metered customers with NEM during 2021, which means that the average monthly usage of these categories is net of behind-the-meter generation. Chart PG&E-4 displays the average monthly usage for each single-metered category without NEM.

Chart PG&E-3: Single-Metered Average Monthly Usage (kWh) by Customer Type With NEM (2021)

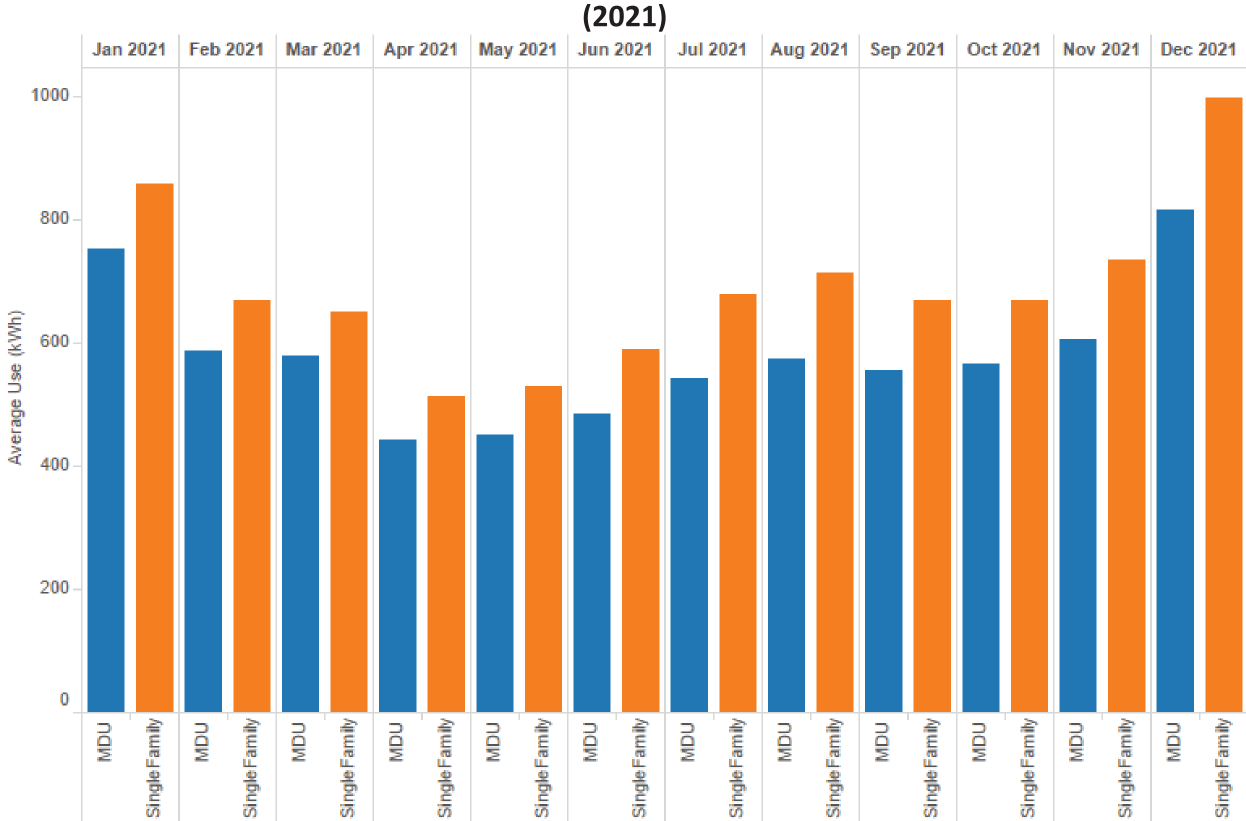
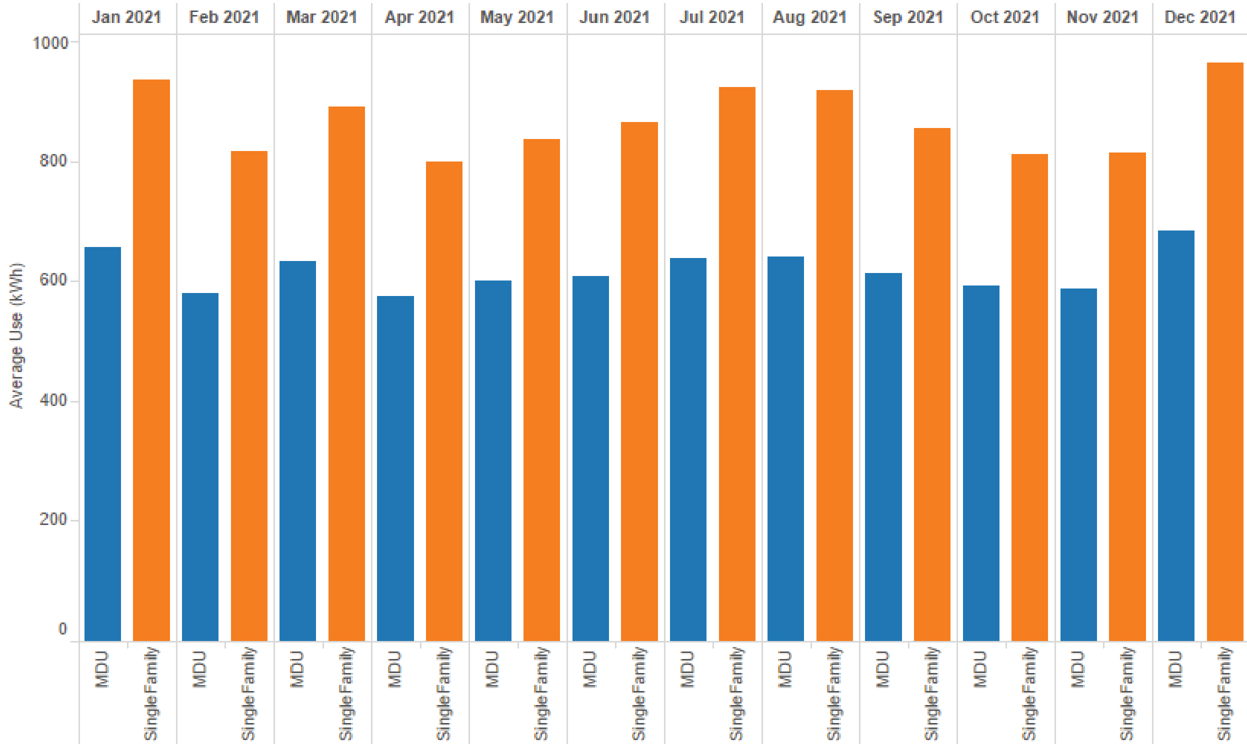


Chart PG&E-4: Single-Metered Average Monthly Usage (kWh) by Customer Type Without NEM (2021)



A comparison of customers with NEM and customers without for 2021 reveals an unsurprising result for both sectors: absent the NEM accounts, usage is relatively flatter for PEV rate customers throughout the study period. This result demonstrates that offsetting consumption with behind-the-meter generation obfuscates researchers' ability to parse PEV load from other site loads for NEM customers using their consumption data alone. Average usage for customers without NEM across months was relatively flat in 2021 with a slight uptick in December. This could have been as a result of loosening COVID-19 restrictions.

In Chart PG&E-5, NEM customers are not segregated among separately-metered customers because the average use (kWh) cannot be shared publicly due to the low penetration among separately-metered customers.

Chart PG&E-5: Separately-Metered Average Monthly Usage (kWh) by Customer Type (2021)

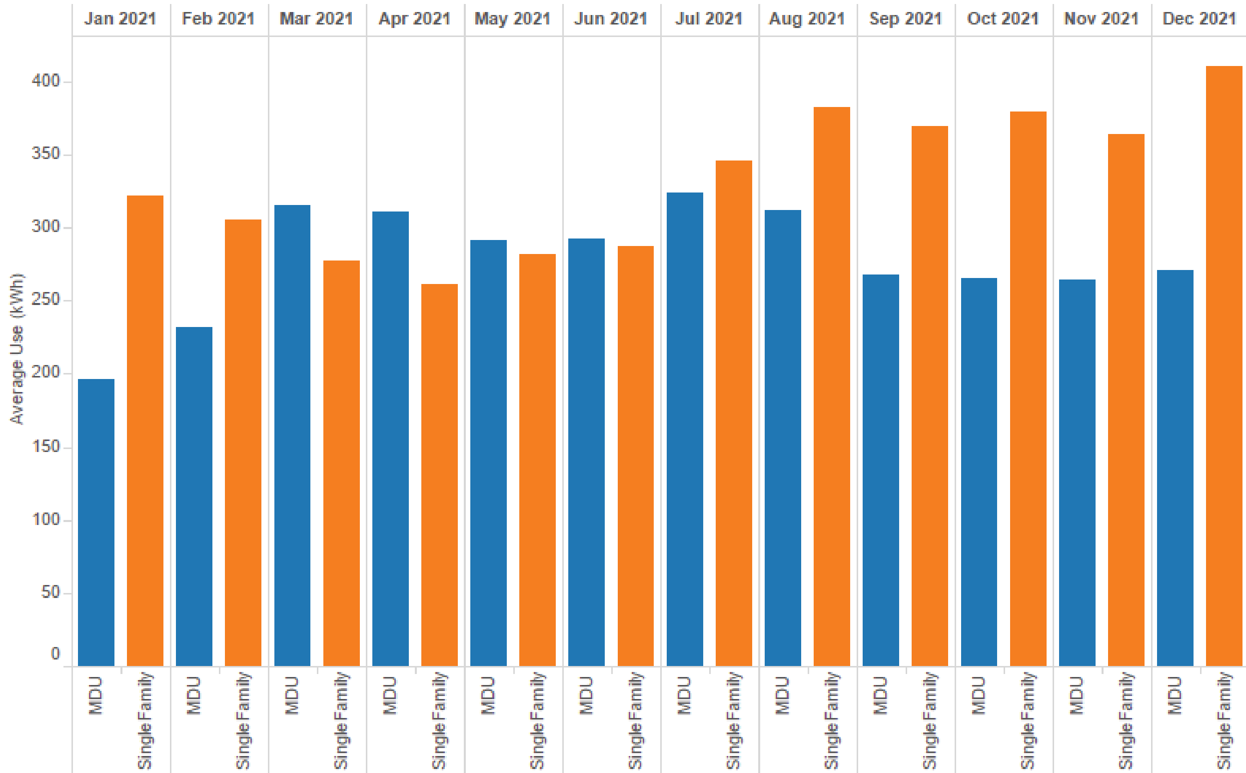


Chart PG&E-5 shows that, absent other loads on the meter, researchers can better observe PEV rate customers' total charging. The results in Chart PG&E-5 show relatively consistent usage during the first half of 2021 for SF customers with a notable increase during the second half. One reason for this could be the loosening of COVID-19 restrictions as vaccinations rolled out. MDU customers showed lower usage during the initial months with relatively consistent usage for the rest of the year.

Average Usage during Time of Use Periods

TOU PEV rates are designed to discourage charging during peak hours and instead encourage charging during off-peak hours when the grid is less stressed and generation costs are lower. For single-metered and separately-metered customers, the time of use periods in 2021 are defined in Table PG&E-1.

One useful way to determine whether the TOU PEV rates are achieving their goal of avoiding peak PEV charging is to measure the distribution of charging in the various time periods. Given that NEM customers have a very unique usage profile, they are segregated from all other single-metered customer groups in Tables PG&E-5-7. Note that for the customer usage comparisons, single-metered and separately-metered customers are independently compared to the general population per their respective TOU schedules. [20]

1. Table PG&E-5 shows the share of peak usage by sector for single-metered and separately-metered PEV customers with and without NEM and compares it to the peak usage of PG&E's entire residential population. In 2021, the share of energy usage during on-peak hours between customers on the single-metered PEV rate and the general population was very similar. Customers without NEM only had an average share of on-peak usage that was 3% less than that of the general population. Similarly, those with NEM had only 3% more during the peak period. The similarity in share of usage during on-peak hours could be a result of increased enrollment in residential TOU rates outside of the PEV rates, as well as lingering COVID-19 restrictions and work-from-home arrangements during 2021, causing a shift in overall home utilization throughout the day for the general customer population. Ultimately, we will need to collect more data post-COVID to fully understand these trends. In contrast, separately-metered customers showed much lower shares of their usage during peak hours compared to the general population. Customers without NEM used energy an average of 19% less during the peak period than the entire residential population, while their NEM counterparts used energy 13% less during that time. As previously noted, the small customer population of NEM customers on EV-B detracts from the meaningfulness of results produced by its data. Because the goal of PEV rates is to encourage customers to charge their vehicles during off-peak hours, the fact that PEV rate customers' peak period usage is less than a third of their overall usage indicates that the PEV TOU rates are achieving this goal among early PEV adopters.
2. Table PG&E-6 shows the off-peak share of usage by sector for customers on both rates, with and without NEM, and compares it to the off-peak share of usage of PG&E's entire residential population. During 2021, single-metered PEV customers showed similar usage to the general population. PEV Customers without NEM had only 5% more of their share during off-peak hours, while their NEM counterparts' share was 11% lower. The similarity in share of usage during off-peak hours for single-metered customers could be a result of the same factors mentioned above. Ultimately, we will need to collect more data post-COVID to fully understand these trends. In contrast, non-NEM separately-metered customers used an average of 28% more energy than the general population, while NEM customers on the same rate used 29% more. Customers on both PEV rates were in line with previous trends and met the off-peak performance expectations consuming most of their energy during this period.
3. Table PG&E-7 shows the share of partial peak usage by sector for customers on both PEV rates, with and without NEM, and compares it to the partial peak usage

[20] For the total residential population data, January to December 2020 data was used to compare to the 2021 PEV data due to the fact that 2021 total residential data is not available until July 2022.

of PG&E's entire residential population. In 2021, single-metered PEV customers had similar share of usage to the general population. PEV Customers without NEM experienced almost the same share of demand during the partial-peak period as the general population – only 2% less – while those with NEM were 2% higher. As noted previously, this could be a result of lingering COVID-19 restrictions in 2021 and the higher enrollment in TOU rates for the general population. Ultimately, we will need to collect more data post-COVID to fully understand these trends. In contrast, separately-metered customers had a noticeably lower share of usage during the partial-peak period compared to the general population. Customers without NEM used an average of 10% less energy, and those with NEM used 16% less. In general, these groups met the performance expectations for their PEV rate by consuming less energy during the partial peak period than the off-peak period.

Collectively, Tables PG&E-5 – PG&E-7 show that customers on both rates are shifting their usage from peak hours to off-peak hours. Specifically, separately-metered customers without NEM are completing, on average, over 70% of their charging during the off-peak period and less than 15% during the peak period. Single-metered customers without NEM are using over 60% of their energy during off-peak periods, as well. This suggests that customers on the PEV rates are responding effectively to their rates' price signals and charging during the off-peak periods.

Table PG&E-5: Share of On-Peak Usage by Tariff and Customer Type (2021)

		Single-Metered					Separately-Metered				
Year	Season	Total Residential Population*	*SF no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	Total Residential Population**	*SF No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2021	Summer	25%	22%	20%	22%	28%	34%	13%	13%	13%	20%
2021	Winter	23%	20%	20%	20%	26%	30%	14%	13%	14%	17%
	Max	25%	22%	20%	22%	28%	34%	14%	13%	14%	20%
	Avg	24%	21%	20%	21%	27%	32%	14%	13%	13%	19%

*Load data used for the analysis are from Jan 2020 to December 2020. (See footnote 20)

**Total Residential Population reflects usage during TOU schedule for each rate.

Table PG&E-6: Share of Off-Peak Usage by Tariff and Customer Type (2021)

		Single-Metered					Separately-Metered				
Year	Season	Total Residential Population*	*SF no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	Total Residential Population**	*SF No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2021	Summer	56%	61%	63%	61%	50%	42%	72%	75%	73%	74%
2021	Winter	60%	64%	65%	64%	56%	45%	70%	74%	71%	72%
	Max	60%	64%	65%	64%	56%	45%	72%	75%	73%	74%
	Avg	58%	63%	64%	63%	53%	44%	71%	74%	72%	73%

*Load data used for the analysis are from Jan 2020 to December 2020. (See footnote 20)

**Total Residential Population reflects usage during TOU schedule for each rate.

Table PG&E-7: Share of Partial-Peak Usage by Tariff and Customer Type (2021)

		Single-Metered					Separately-Metered				
Year	Season	Total Residential Population*	*SF no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	Total Residential Population**	*SF No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2021	Summer	19%	17%	16%	17%	22%	23%	15%	12%	14%	6%
2021	Winter	17%	15%	15%	15%	18%	25%	16%	13%	15%	10%
	Max	19%	17%	16%	17%	22%	25%	16%	13%	15%	10%
	Avg	18%	16%	16%	16%	20%	24%	16%	12%	14%	8%

*Load data used for the analysis are from Jan 2020 to December 2020. (See footnote 20)

**Total Residential Population reflects usage during TOU schedule for each rate.

Average Load Profiles for PEV Rates

Depicted below in Charts PG&E-6 and PG&E-7 are the average daily load profiles for the single-metered and separately-metered rate groups for each sector during 2021. In 2021, the load profiles demonstrate that for all rates and sectors, high off-peak usage corresponds to the PEV rate price signals, i.e., customers are largely responding to the price signal and primarily charging during off-peak hours (12:00 a.m. to 3:00 p.m. with the bulk of the load occurring from 12:00 a.m. to 5:00 a.m.). The load profile during 2021 for both SF and MDU customers shows a spike in demand at midnight with a second smaller spike during the peak-hour period 6:00 p.m. to 10 p.m. The response to price signals is more clearly depicted in the data from the separately-metered customers (Chart PG&E-7) where the majority of the usage occurs during off-peak hours during 2021.

Chart PG&E-6: Average Load Profile for SF and MDU Single-Metered by Weekday and Weekend (2021)

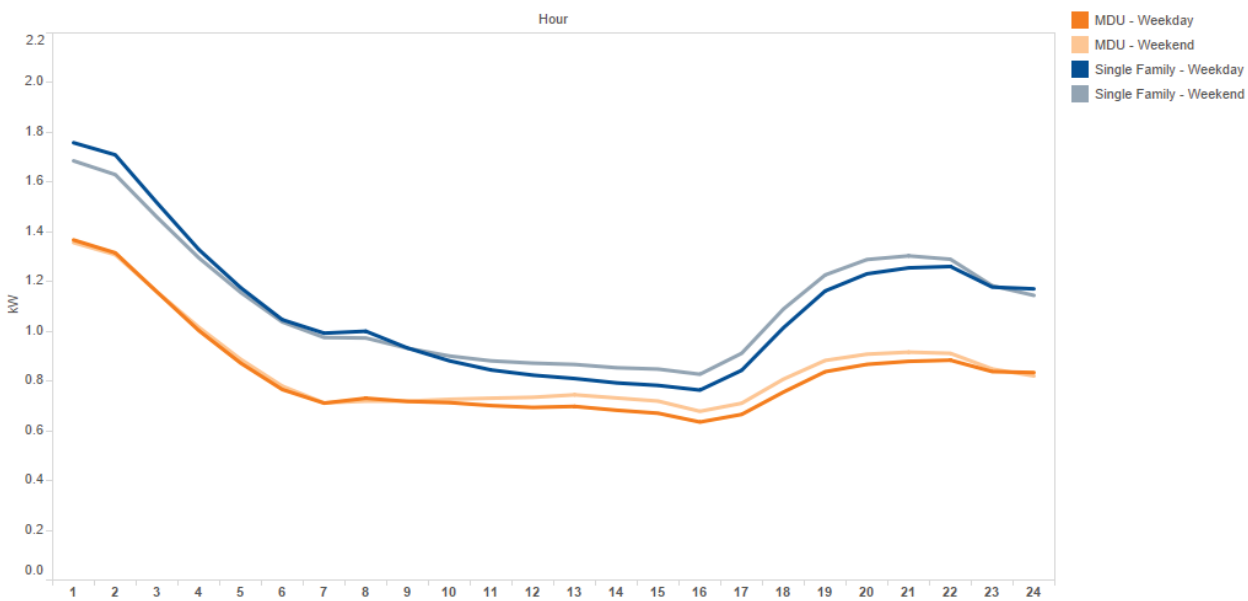
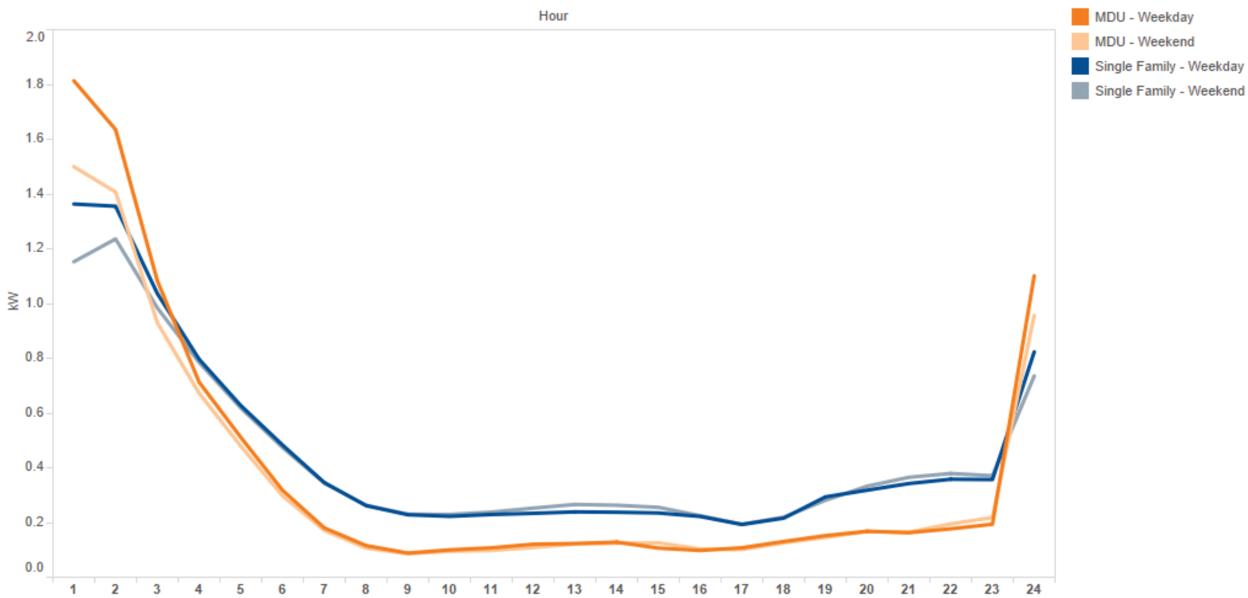


Chart PG&E-7: Average Load Profile for SF and MDU Separately-Metered by Weekday and Weekend (2021)



Non-Coincident Peak Load

Collectively, the data in Table PG&E-8, and Charts PG&E-8 – PG&E-9 suggest that, even though charging is primarily occurring in the off-peak hours, the average household with a PEV will have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average household without a PEV.

- Table PG&E-8 shows the monthly comparison of the average non-coincident peak for the single-metered and separately-metered PEV customer sectors and the full residential population. The average non-coincident peak was 3.13 kW higher for the single-metered group category compared to the average residential peak[21]. Among SF customers, PEV rate customers were 2.66 kW higher than non-PEV rate customers, and MDU customers were 3.51 kW higher. Comparatively, the average non-coincident peak for separately-metered customers was 3.52 kW higher than the average residential peak. Among SF customers, PEV rate customers were higher than the residential population by 2.66 kW, while MDU customers were 5.41 kW higher.
- Chart PG&E-8 displays the average monthly non-coincident peak loads for single-metered customers during 2021.
- Chart PG&E-9 displays the average monthly non-coincident peak loads for separately-metered customers during 2021. MDU customers showed lower Non-Coincident Peak Loads

[21] The average non-coincident peak was calculated by denoting the maximum hourly interval for each account within the month. These maximum values were then summed for each category. The average is then calculated by dividing the total by the number of customers. The average non-coincident peak is therefore an approximation of the maximum demand for customer in each stratum.

during the last quarter of the year compared to the first months in 2021. This may be due to an outreach campaign PG&E executed in late 2021 to confirm eligibility for the rate which resulted in the removal of some customers from the rate.

Table PG&E-8: Monthly Average Non-Coincident Peak Load (kW) (2021)

Year	Month	Residential Population*	Single Family Population*	MDU Population*	All Single-metered	Single Family Single-metered	MDU Single-metered	All Separately-metered	Single Family Separately-metered	MDU Separately-metered
2021	Jan	4.03	4.50	2.84	7.37	7.48	6.25	*6.29*	*5.83*	6.98
2021	Feb	3.73	4.18	2.60	7.17	7.26	6.18	*6.85*	*6.17*	7.87
2021	Mar	3.95	4.45	2.69	7.15	7.23	6.22	8.69	7.82	9.99
2021	Apr	3.86	4.35	2.63	6.92	6.99	6.08	8.86	8.11	9.95
2021	May	4.20	4.78	2.73	7.12	7.21	6.18	8.21	8.18	8.25
2021	Jun	4.50	5.16	2.83	7.46	7.56	6.37	8.31	7.98	*8.81*
2021	Jul	4.66	5.35	2.93	7.54	7.64	6.40	8.23	*7.62*	*9.12*
2021	Aug	5.12	5.89	3.15	7.83	7.96	6.43	*7.90*	*7.28*	*8.83*
2021	Sep	4.67	5.35	2.91	7.46	7.56	6.33	*7.58*	*7.61*	*7.54*
2021	Oct	4.10	4.64	2.71	7.36	7.45	6.29	*7.19*	*7.38*	*6.90*
2021	Nov	3.95	4.43	2.70	7.40	7.49	6.32	*7.38*	*7.62*	7.02
2021	Dec	4.33	4.91	2.85	7.93	8.06	6.61	*7.87*	*8.28*	7.23
Average		4.26	4.83	2.80	7.39	7.49	6.31	7.78	7.49	8.21

*Load data used for the analysis are from Jan 2020 to December 2020. (See footnote 20)

*Italicized fields are estimates with a precision greater than +/- 10% at a 90% confidence interval.

Chart PG&E-8: Average Non-Coincident Peak Load (kW) for Single-Metered by Customer Type by Month (2021)

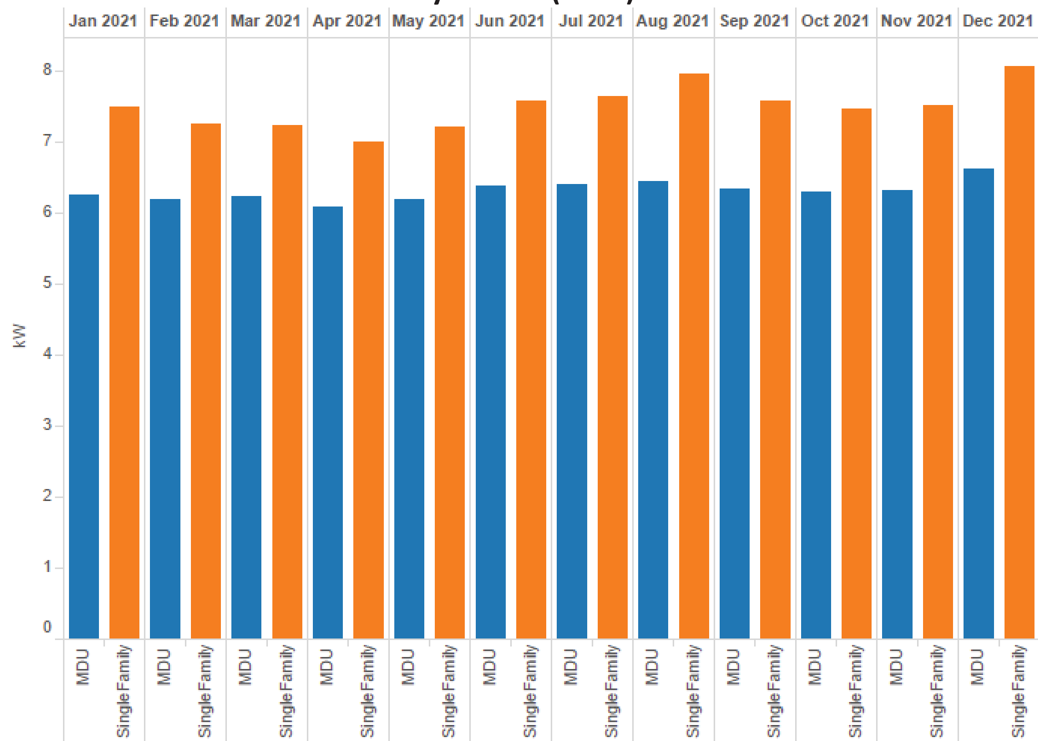
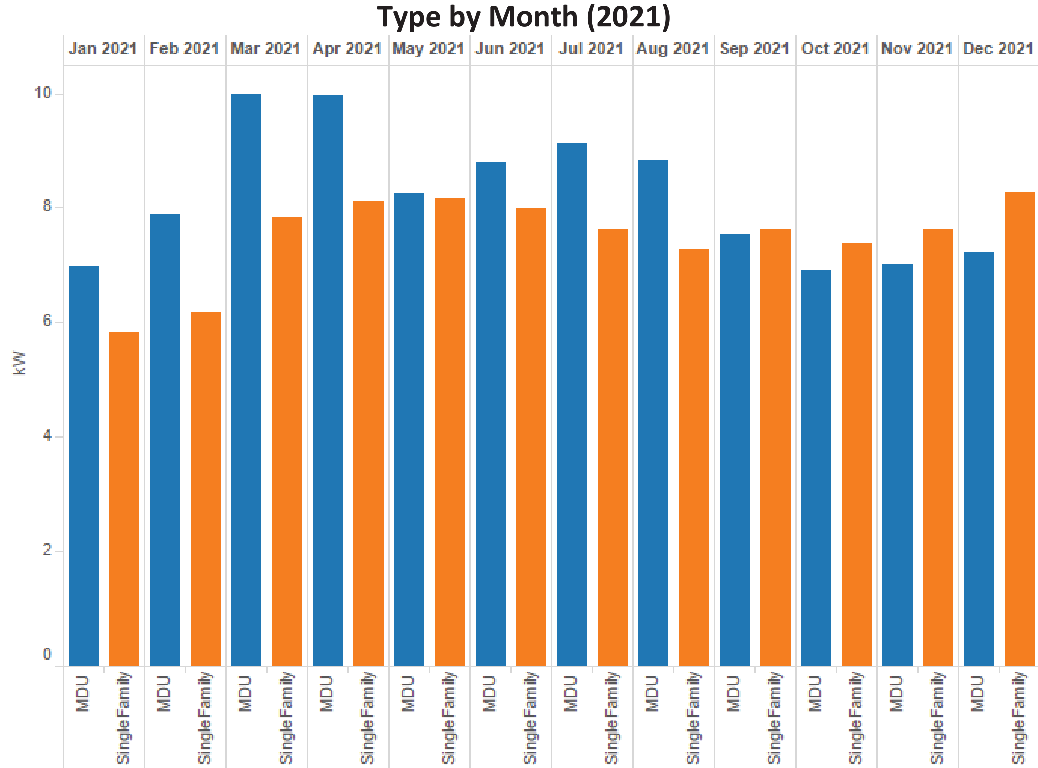


Chart PG&E-9: Average Non-Coincident Peak Load (kW) for Separately-Metered by Customer Type by Month (2021)



Diversified Peak Load

The time of diversified peak load gives the time that the group peaks as a whole. The time of diversified (or group) peak load is generally the same for all categories of single-metered and separately-metered customers. Tables PG&E-9 - PG&E-11 show that the diversified peak load occurs between 1:00 a.m. to 2:00 a.m. for all categories in all months for both EV rates in 2021. Tables PG&E-9a-c show that the diversified peak load generally occurs between 1:00 a.m. to 2:00 a.m. for all categories in all months for both EV rates in 2021. The general trend of the data suggests that the early adopter group of customers on the PEV rates is charging during the off-peak periods thereby achieving the intent of the rate designs.

Table PG&E-9: Time and Associated Demand of Diversified Peak Load (kW) – Entire Residential Population (2021)

Year	Month	Residential Population Demand*	Residential Population Hour	SF Population Demand	SF Population Hour	MDU Population Demand	MDU Population Hour
2021	Jan	0.96	13	1.17	13	0.72	19
2021	Feb	1.10	13	1.33	13	0.69	20
2021	Mar	1.18	14	1.43	14	0.62	20
2021	Apr	1.29	14	1.56	14	0.63	21
2021	May	1.33	14	1.60	14	0.76	15
2021	Jun	1.40	14	1.70	14	0.78	16
2021	Jul	1.41	14	1.68	14	0.82	15
2021	Aug	1.65	20	1.94	20	0.92	16
2021	Sep	1.60	20	1.90	20	0.89	15
2021	Oct	1.10	19	1.27	19	0.70	20
2021	Nov	1.05	12	1.23	12	0.67	19
2021	Dec	1.01	19	1.15	12	0.70	20

*Load data used for the analysis are from Jan 2020 to December 2020. (See footnote 20)

Table PG&E-10: Time and Associated Demand of Diversified Peak Load (kW) – Single-Metered (2021)

Year	Month	Single-metered Demand	Single-metered Hour	SF Single-metered Demand	SF Single-metered hour	MDU Single-metered Demand	MDU Single-metered Hour
2021	Jan	1.83	1	1.87	1	1.40	1
2021	Feb	1.79	1	1.82	1	1.43	1
2021	Mar	1.78	1	1.82	1	1.42	1
2021	Apr	1.69	1	1.71	1	1.40	1
2021	May	1.70	1	1.74	1	1.46	1
2021	Jun	2.17	1	2.21	1	1.72	1
2021	Jul	2.04	1	2.08	1	1.56	1
2021	Aug	2.04	1	2.09	1	1.56	1
2021	Sep	2.01	1	2.05	1	1.54	1
2021	Oct	1.79	1	1.82	1	1.49	1
2021	Nov	1.86	1	1.91	1	1.48	1
2021	Dec	2.13	2	2.17	2	1.66	1

Table PG&E-11: Time and Associated Demand of Diversified Peak Load (kW) – Separately-Metered (2021)

Year	Month	Separately-metered Demand	Separately-metered Hour	SF Separately-metered Demand	SF Separately-metered hour	MDU Separately-metered Demand	MDU Separately-metered Hour
2021	Jan	*1.35*	1	*1.36*	2	*1.54*	1
2021	Feb	*1.94*	2	*1.75*	2	*2.36*	1
2021	Mar	*2.05*	2	*1.90*	2	*2.64*	1
2021	Apr	*1.92*	2	*1.82*	2	*2.66*	1
2021	May	*1.95*	1	*1.93*	2	*2.21*	1
2021	Jun	*2.19*	1	*1.94*	2	*2.78*	1
2021	Jul	*2.05*	2	*1.91*	2	*2.91*	1
2021	Aug	*2.07*	1	*1.99*	1	*2.75*	2
2021	Sep	*1.96*	1	*1.81*	1	*2.52*	1
2021	Oct	*1.80*	1	*1.86*	2	*2.22*	1
2021	Nov	*1.80*	1	*1.80*	1	*2.02*	2
2021	Dec	*1.98*	1	*1.98*	1	*1.98*	1

*Italicized fields are estimates with a precision greater than +/- 10% at a 90% confidence interval.

Taken together, Tables PG&E-9 – PG&E-11 suggest that although the early adopter PEV customers may have a higher average maximum demand, those customers on the PEV rates tend to hit their maximum demand while non-PEV customers are at some of their lowest usage. Thus, there is a diversity benefit created by the TOU rates. However, at the most local service assessment level perspective (i.e., a single household or set of households serviced by a single transformer), the value of this diversity is limited by the fact that the distribution system must still be prepared to accommodate PEV charging during the peak period since these customers can, and occasionally do, charge during those times.

Non-Residential PEV Rates

Business EV Rate

As of the date of this report, PG&E has two non-residential PEV rates - the Business Low Use EV Rate (“BEV-1”) for customers with up to and including 100 kW demand for their PEV charging infrastructure and the Business High Use EV Rate (“BEV-2”) for customers with demand equal to 100kW and over for their EV charging infrastructure. Customers on the BEV-2 rate can be secondary or primary/transmission customers and have slightly different energy prices. The BEV rates work as a monthly subscription charge based on customers’ maximum monthly EV charging kW consumption. Both rate plans use a TOU rate structure. The TOU values vary a few cents between the BEV-1 and BEV-2 options but follow largely the same structure: they offer on-peak, off-peak, and super off-peak energy prices according to the time periods in Table PG&E-12. Regardless of season, or day of the week, both rates seek to encourage usage in off-peak hours. Both BEV rates include off-peak hours from 2:00 p.m. to 4:00 p.m. and 9:00 p.m. to 9:00 a.m. and super off-peak hours 9:00 a.m. to 2:00 p.m. during weekdays and weekends.

Table PG&E-12: Tariff Type and Rate ($/kWh) in 2021

Hour	Rate: BEV-1 Every day including weekends and holidays, all year	Rate: BEV-2-S Every day including weekends and holidays, all year	Rate: BEV-2-P Every day including weekends and holidays, all year
12mn - 1am	$0.13419	$0.12773	$0.12419
1am - 2am	$0.13419	$0.12773	$0.12419
2am - 3am	$0.13419	$0.12773	$0.12419
3am - 4am	$0.13419	$0.12773	$0.12419
4am - 5am	$0.13419	$0.12773	$0.12419
5am - 6am	$0.13419	$0.12773	$0.12419
6am - 7am	$0.13419	$0.12773	$0.12419
7am - 8am	$0.13419	$0.12773	$0.12419
8am - 9am	$0.13419	$0.12773	$0.12419
9am - 10am	$0.10753	$0.10446	$0.10153
10am - 11am	$0.10753	$0.10446	$0.10153
11am - 12nn	$0.10753	$0.10446	$0.10153
12nn - 1pm	$0.10753	$0.10446	$0.10153
1pm - 2pm	$0.10753	$0.10446	$0.10153
2pm - 3pm	$0.13419	$0.12773	$0.12419
3pm - 4pm	$0.13419	$0.12773	$0.12419
4pm - 5pm	$0.32620	$0.34096	$0.33307
5pm - 6pm	$0.32620	$0.34096	$0.33307
6pm - 7pm	$0.32620	$0.34096	$0.33307
7pm - 8pm	$0.32620	$0.34096	$0.33307
8pm - 9pm	$0.32620	$0.34096	$0.33307
9pm - 10pm	$0.13419	$0.12773	$0.12419
10pm - 11pm	$0.13419	$0.12773	$0.12419
11pm - 12mn	$0.13419	$0.12773	$0.12419

Legend:

	All year
On	
Off	
Super Off	

* Rates effective through December 31, 2021. There is also a subscription component to the BEV rate. For details see Electric Schedule BEV, Business Electric Vehicles, retrieved from https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_BEV.pdf

Table PG&E-13 depicts price ratios for the TOU periods.

Table PG&E-13: Price Ratios for 2021

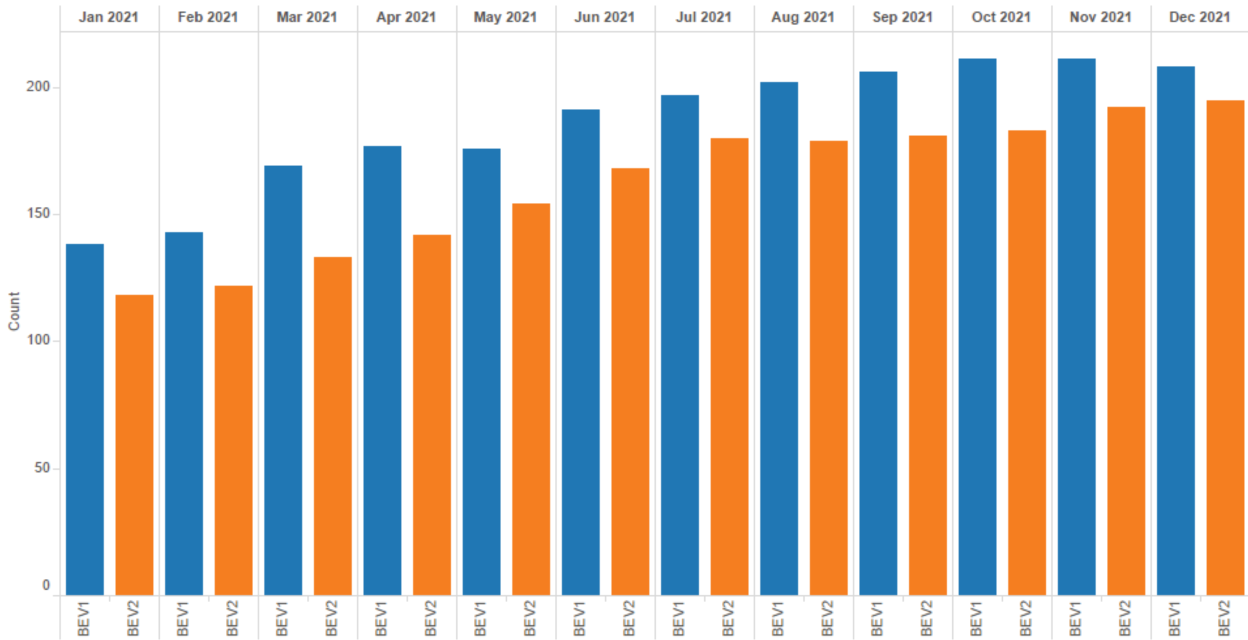
	BEV-1		BEV-2-S		BEV-2-P	
Season	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak
All year	0.33	0.80	0.31	0.82	0.30	0.82

BEV Rate Enrollment and Growth

Per Decision 19-10-055,[22] which approved a 2-phase launch, PG&E's BEV rate was launched with limited functionality in May 2020 and launched with full functionality in October 2020. There has been steady growth in enrollment for both the BEV-1 and BEV-2 rates since their launch. BEV-1 rate customers tend to be smaller businesses with fewer or smaller vehicles, or they are active in managing their charging. BEV-2 customers tend to be larger commercial customers such as transit operators with large vehicles, or charging sites with high utilization, often across multiple vehicles or fleets, such as Direct Current Fast Charge (DCFC) operators. During the 2021 study period, BEV-1 accounts have increased 50% and BEV-2 accounts have increased 65%, as seen in Chart PG&E-10.

[22] Decision 19-10-055.

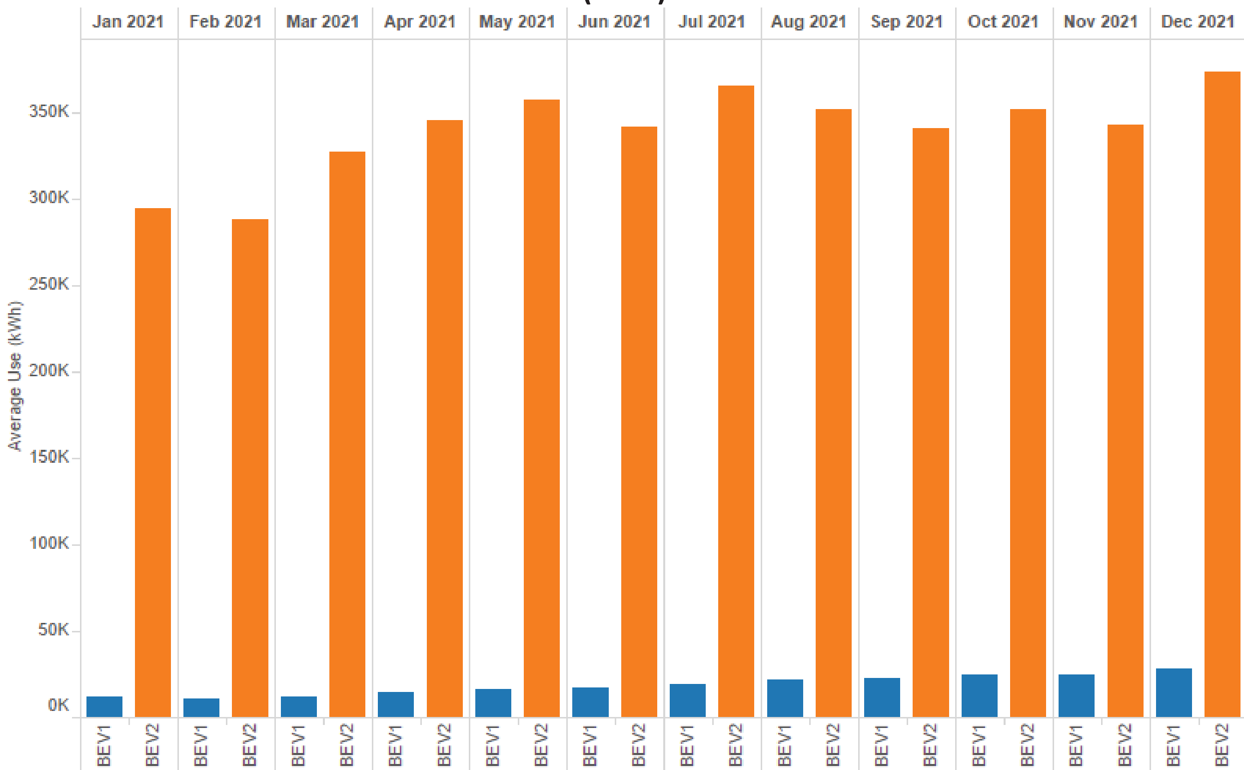
Chart PG&E-10: BEV Rate Accounts by Customer Type (2021)



Average Monthly Usage for BEV Rate Customers

Keeping in mind the cautions about the data collected mentioned in the section on residential PEV rates above, Chart PG&E-11 displays the average monthly usage for BEV-1 and BEV-2 customers in 2021. As expected from the construct of the two rates, BEV-2 customers have a much higher average monthly usage than customers on BEV-1, although the customer sample for the two rates is still too small to make any conclusions.

Chart PG&E-11: BEV Average Monthly Usage (kWh) by Customer Type (BEV-1 and BEV-2) (2021)



Average Usage during Time of Use Periods

Similar to residential PEV rates, commercial BEV rates are designed to discourage charging during on-peak hours and encourage charging during off-peak and super off-peak hours. The time of use periods for both BEV rates are defined in Table PG&E-12.

One useful way to determine whether the TOU PEV rates are achieving their goal of avoiding peak PEV charging is to measure the distribution of charging in the various time periods.

- Table PG&E-14 shows the share of on-peak, off-peak, and super off-peak usage for BEV-1 customers for the summer and winter seasons[23]. The energy usage is distributed relatively evenly between the three TOU periods, with slightly higher usage in the off-peak period. More charging could be occurring during the off-peak period than the super off-peak period due to the transportation needs of the customers. The super off-peak period occurs between 9 a.m. to 2 p.m. and many customers may need to be using their vehicles during this period and cannot be charging. However, the goal of BEV rates is to encourage customers to charge their vehicles during off-peak and super off-peak hours. It is important to note that the number of customers on the BEV-1 rate is still growing as it was only

[23] The BEV rate does not include any seasonality. Winter and Summer prices are the same. The distinction is included here to compare customer usage to different weather patterns and time of year.

opened to enrollment in 2020 and therefore the energy usage of the average customer on said rate may change in the future as customer enrollment increases and the types of commercial customers utilizing the rate become more diverse.

- Table PG&E-15 shows the share of on-peak, off-peak, and super off-peak usage for BEV-2 customers for the summer and winter seasons. The energy usage is distributed evenly between the three TOU periods, with slightly higher usage during the off-peak period. This could be due to the unique and specific transportation needs of the customers on the BEV-2 rate. However, the goal of BEV rates is to encourage customers to charge their vehicles during off-peak and super off-peak hours. It is important to note that the number of customers on the BEV-2 rate is still growing as it was only opened to enrollment in 2020 and therefore the energy usage of the average customer on said rate may change in the future as customer enrollment increases and the types of commercial customers utilizing the rate become more diverse.

Collectively, Tables PG&E-14 and 15 show that the majority of energy usage of customers on the BEV rates does not occur during peak hours. BEV-1 customers are completing, on average, 70% of their charging during the off-peak and super off-peak period and BEV-2 customers are completing, on average, 68% of their charging during the off-peak and super off-peak period. This suggests that customers on the BEV rates are responding effectively to their rates' price signals and charging during the off-peak and super off-peak period.

Table PG&E-14: Share of Usage for BEV-1 by TOU Period (2021)

Year	Season	On-Peak BEV-1	Off-Peak BEV-1	Super Off-Peak BEV-1
2021	Summer	31%	38%	31%
2021	Winter	28%	37%	35%
	Max	31%	38%	35%
	Avg	30%	37%	33%

* Numbers may not add up to 100% due to rounding

Table PG&E-15: Share of Usage for BEV-2 by TOU Period (2021)

Year	Season	On-Peak BEV-2	Off-Peak BEV-2	Super Off-Peak BEV-2
2021	Summer	33%	35%	32%
2021	Winter	32%	34%	33%
	Max	33%	35%	33%
	Avg	33%	35%	33%

* Numbers may not add up to 100% due to rounding

Average Load Profiles for BEV Rates

Depicted below in Charts PG&E-12 and PG&E-13 are the average daily load profiles for BEV-1 and BEV-2 rate groups for weekday and weekend in 2021. The load profiles demonstrate that high off-peak usage corresponds to the PEV rate price signals, *i.e.*, customers are largely responding to the price signal and charging during super off-peak hours (9:00 a.m. to 2:00 p.m.). There is still some charging that is occurring during peak hours (4:00 p.m. to 9:00 p.m.) which is likely due to inflexibility of business needs and/or use of public charging by customers on their commute home. As expected from the rate design, the average kW demand is higher for BEV-2 customers and the BEV-2 customer load profiles does show that customers are charging during the super off-peak period. It also shows that BEV-2 customers are also still charging during some of the on-peak hours which may be attributable to the DCFC customers who are less aware of the TOU price signals or less able to adjust their charging time. The lower usage during the off-peak period despite the low energy prices may be a result of the ability to charge during the middle of the day to meet business needs as well as limited use of public charging by customers during those hours. There is very little difference between the weekday and weekend load profiles for the BEV-1 rate, which may suggest that BEV rate customers have similar business operations and charging needs throughout the week. [24] BEV-2 weekend load profiles show higher peaks compared to weekday peaks during the same hours. This could be a result of COVID-19 continuing restrictions. However, this may change as more customers with varying business operations and needs enroll in the rate.

[24] Weekend and weekday prices are the same on the BEV rates as are the TOU periods. Therefore, any change in charging pattern between weekend and weekday should not be attributed to differences in price signal.

Chart PG&E-12: Average Load Profile for BEV-1 Customer by Weekday and Weekend (2021)

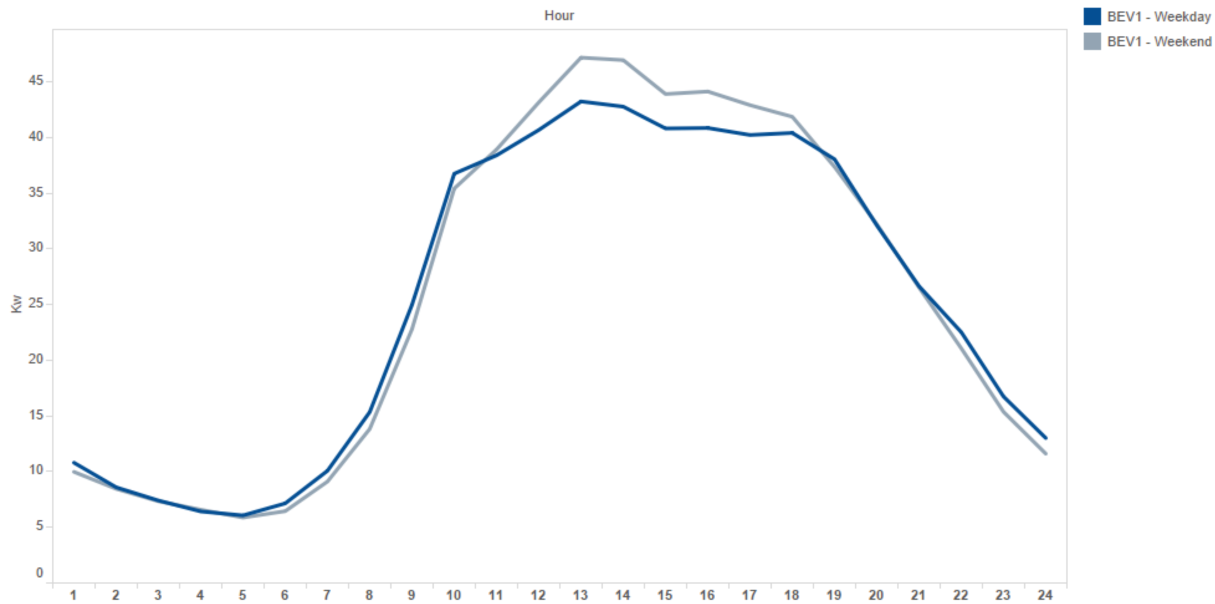
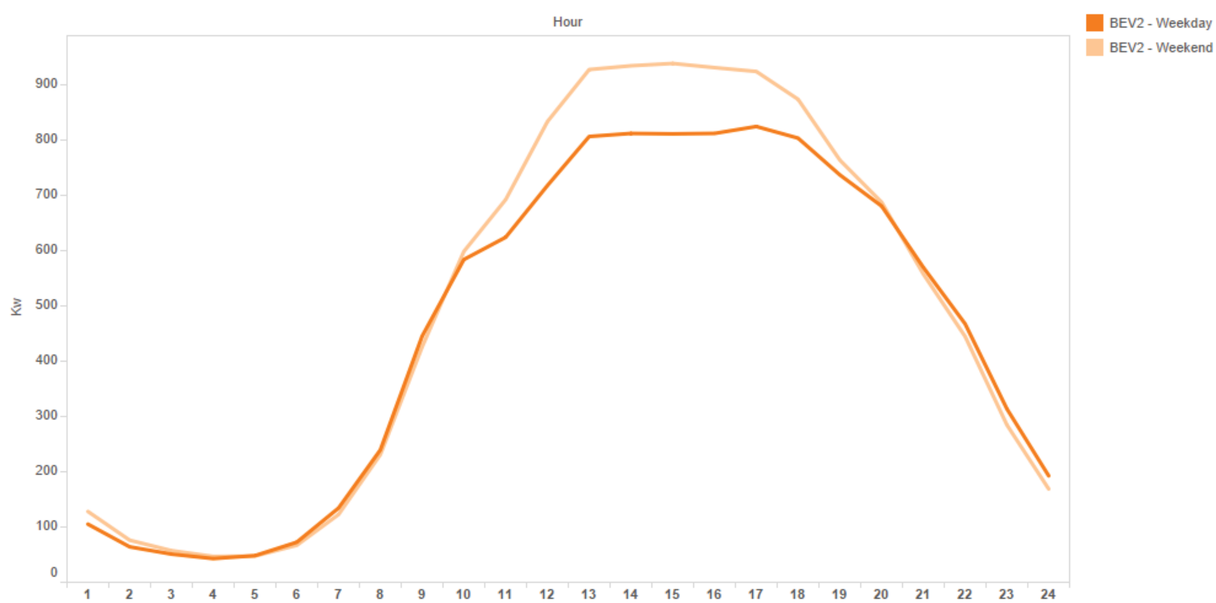


Chart PG&E-13: Average Load Profile for BEV-2 Customer by Weekday and Weekend (2021)



Non-Coincident Peak Load

To compare non-coincident peak loads, the two BEV rates were compared to commercial customers on commercial rates with similar kW demand. The BEV-1 rate was compared to a general population on the A-10 rate, which are commercial customers with kW demand that does not exceed 499 kW. The peak load on the BEV-2 rate was compared to that of customers on the E-19 rate, who are customers with 500 kW demand or higher. Similar to residential customers, the average commercial customer with charging installations will generally have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average commercial customer without PEV charging installations.

- Table PG&E-16 shows the monthly comparison of the average non-coincident peak between BEV-1 and A-10 customers, and between BEV-2 and E-19 customers. The average non-coincident peak was approximately 42 kW higher for the BEV-1 group category compared to the average A-10 commercial population peak.[25] For the BEV-2 group, the average non-coincident peak was approximately 137 kW higher compared to the average E-19 commercial population peak. Chart PG&E-14 shows a monthly average non-coincident peak load for each rate.

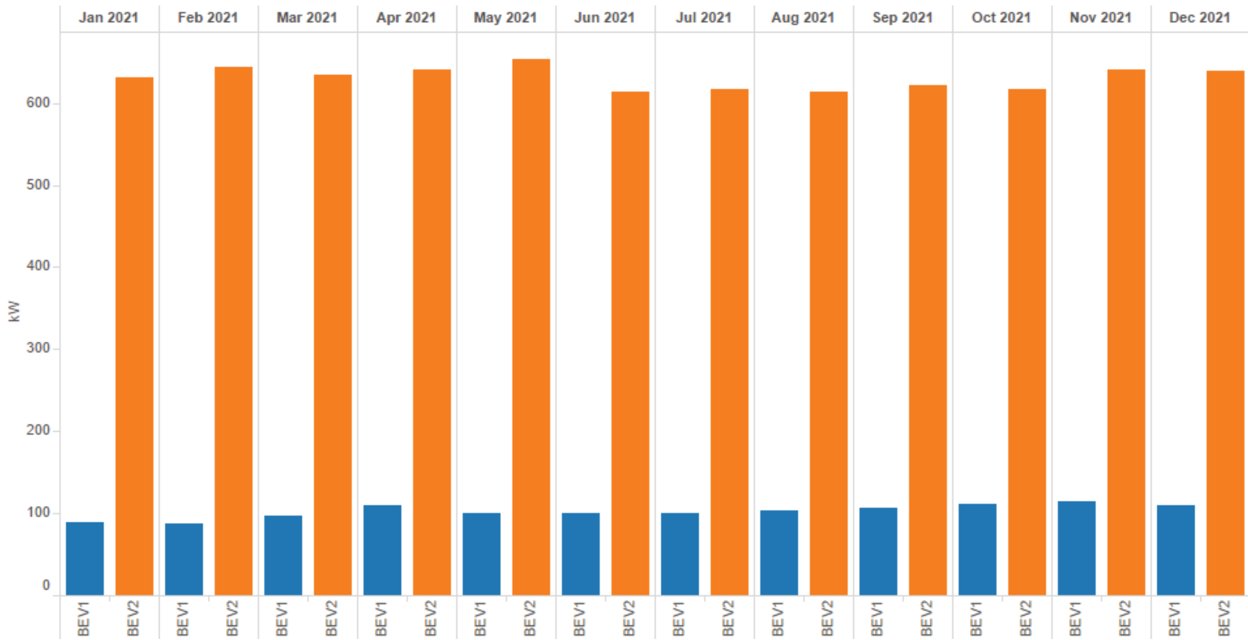
Table PG&E-16: Monthly Average Non-Coincident Peak Load (kW) (2021)

Year	Month	Non-Residential A-10 Population*	BEV-1**	Non-Residential E-19 Population*	BEV-2
2021	Jan	57.63	88.93	465.22	630.75
2021	Feb	60.25	88.18	496.39	644.46
2021	Mar	61.62	97.32	499.58	634.09
2021	Apr	53.34	108.97	454.02	641.35
2021	May	59.76	100.25	504.98	654.26
2021	Jun	63.61	99.65	514.80	614.03
2021	Jul	61.61	100.83	497.13	617.23
2021	Aug	69.53	104.00	549.10	614.53
2021	Sep	65.95	106.36	537.87	621.31
2021	Oct	61.81	111.17	510.14	616.89
2021	Nov	55.92	113.85	466.69	640.11
2021	Dec	53.67	110.00	431.59	639.73
Avg		60.39	102.46	493.96	630.73

*A-10 and E19 load data used for the analysis are from Jan 2020 to December 2020. (See footnote 20)
** BEV1 limit is 100kW. Usage may exceed 100kW if a customer overextends their charging and exceeds 100kW, in which case overage fees are applied per kW over 100kW.

[25] The average non-coincident peak was calculated by denoting the maximum hourly interval for each account within the month. These maximum values were then summed for each category. The average is then calculated by dividing the total by the number of customers. The average non-coincident peak is therefore an approximation of the maximum demand for customer in each stratum.

Chart PG&E-14: Average Non-Coincident Peak Load (kW) by Customer Type (BEV-1 and BEV-2) by Month (2021)



Diversified Peak Load

Different than the residential PEV rates, the time of diversified (or group) peak load for both BEV rates is reached during the afternoon and early evening hours. Table PG&E--17 shows that the diversified peak load occurs between 1:00 p.m. and 4:00 p.m. for BEV-1 customers and between 2:00 p.m. and 3:00 p.m. for BEV-2. This suggests that customers on both BEV rates are generally peaking during non-peak hours, achieving the intent of the time-of-use structure. The BEV-1 customers are primarily peaking at approximately the 1:00 p.m. and 2:00 p.m. mark, with a few months peaking at the 4:00 p.m. hour mark, crossing the threshold into the peak period pricing TOU period. BEV-2 customers are primarily peaking at 2:00 p.m. This suggests that BEV customers are generally responding to the price signals. The few months where peaking happens during peak periods may be due to the type of customers enrolled on the BEV-1 rate and their unique charging needs. Due to how recent the rate still is, the impacts of COVID-19 restrictions, and how limited historical data is, these trends could continue to change in subsequent months.

Table PG&E-17: Time and Associated Demand of Diversified Peak Load (kW) – Entire Residential Population (2021)

Year	Month	Non-Residential A-10 Population Demand*	Non-Residential A-10 Population Hour*	BEV-1 Demand	BEV-1 Hour	Non-Residential E-19 Population Demand*	Non-Residential E-19 Population Hour*	BEV-2 Demand	BEV-2 Hour
2021	Jan	30.25	11	44.64	16	313.09	12	1,244.22	15
2021	Feb	30.57	13	50.99	14	342.68	14	1,327.34	15
2021	Mar	30.43	13	55.47	14	345.37	14	1,286.84	16
2021	Apr	29.01	14	59.40	14	299.78	13	1,344.88	16
2021	May	33.71	13	63.99	14	338.36	14	1,283.88	13
2021	Jun	34.68	14	60.27	16	343.82	14	1,222.75	16
2021	Jul	33.87	14	69.87	16	328.30	14	1,222.89	15
2021	Aug	38.70	14	76.56	17	373.12	14	1,216.26	14
2021	Sep	34.55	14	94.67	13	356.02	14	1,245.40	13
2021	Oct	33.97	15	81.86	13	353.28	15	1,222.13	17
2021	Nov	27.28	14	106.08	13	322.71	15	1,309.32	16
2021	Dec	24.87	12	105.45	10	286.20	13	1,399.53	15

*A10 and E19 load data used for the analysis are from Jan 2020 to December 2020. (See footnote 20)

**Italicized fields are estimates with precision > +-10% at 90% CI.

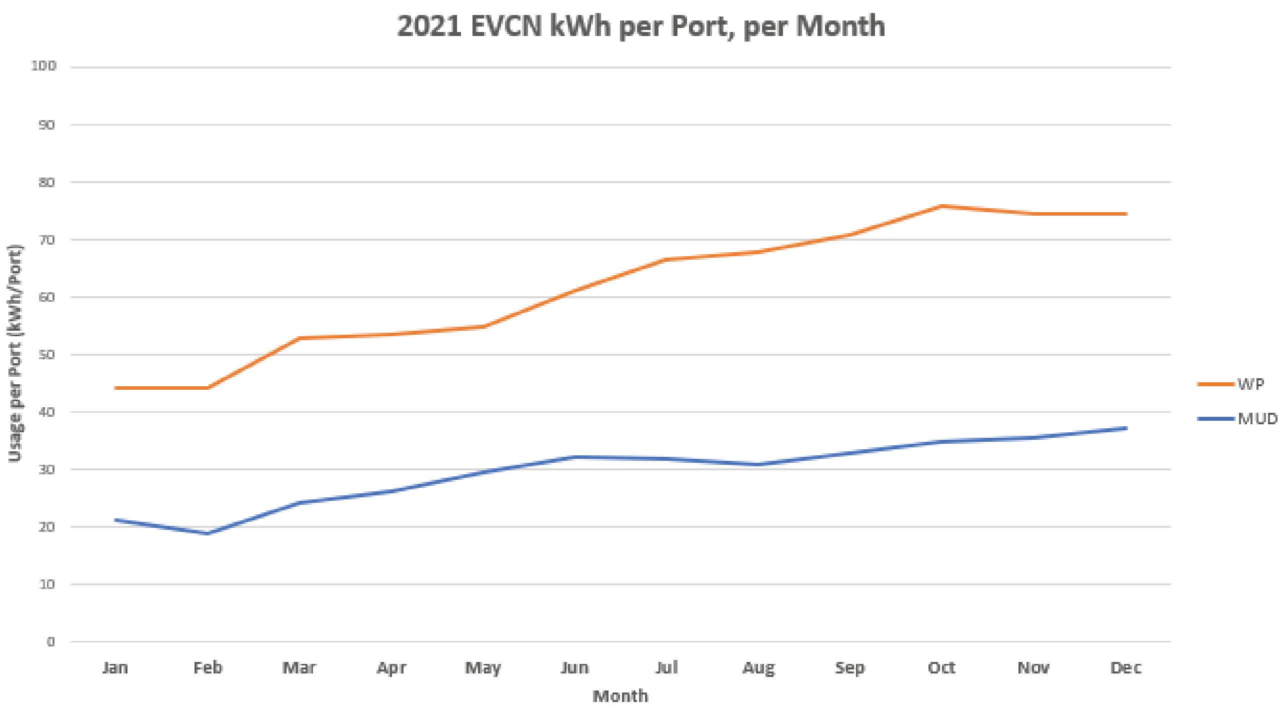
Table PG&E-17 also shows that BEV customers, particularly BEV-2 customers, have significantly higher demand than the non-PEV, non-residential customers. It also shows that BEV rate customers and non-PEV, non-residential rate customers are hitting their maximum demand at similar times in the day. This may change as more customers with diverse business needs enroll in the BEV rate. However, even if BEV customer peak load occurs at a different time than the general non-PEV, non-residential customer peak load, the local service and distribution system must still be prepared to accommodate PEV charging during the peak period since these customers can still charge during those times.

Transportation Electrification Program Load Data

Average Monthly Usage for PG&E Programs

The average monthly utilization per port in chart PG&E-15a shows utilization for PG&E's Electric Vehicle Charge Network (EVCN) program for both Multi-Unit Dwellings (MUD) [26] and Workplaces (WP) as distinguished in Decision 16-12-065. EVCN is PG&E's Light Duty Vehicle program. The metric displayed in this chart is defined as the average kWh/port for each month for EVCN sites. As seen in Chart PG&E-15a, the average monthly utilization per port remained relatively low in early 2021, due to continuing COVID-19 restrictions which have driven down utilization since March 2020. However, monthly usage continues to increase.

Chart PG&E-15a: PG&E EVCN Program Average Monthly Usage (kWh) by Port (2021)



The average monthly utilization per site in chart PG&E-15b shows utilization for PG&E's Electric Vehicle Fleet program. This is PG&E's Medium Duty/Heavy Duty (MD/HD) EV program. Please note the difference in this chart which measures average monthly kWh/site compared to average monthly kWh/port for EVCN.

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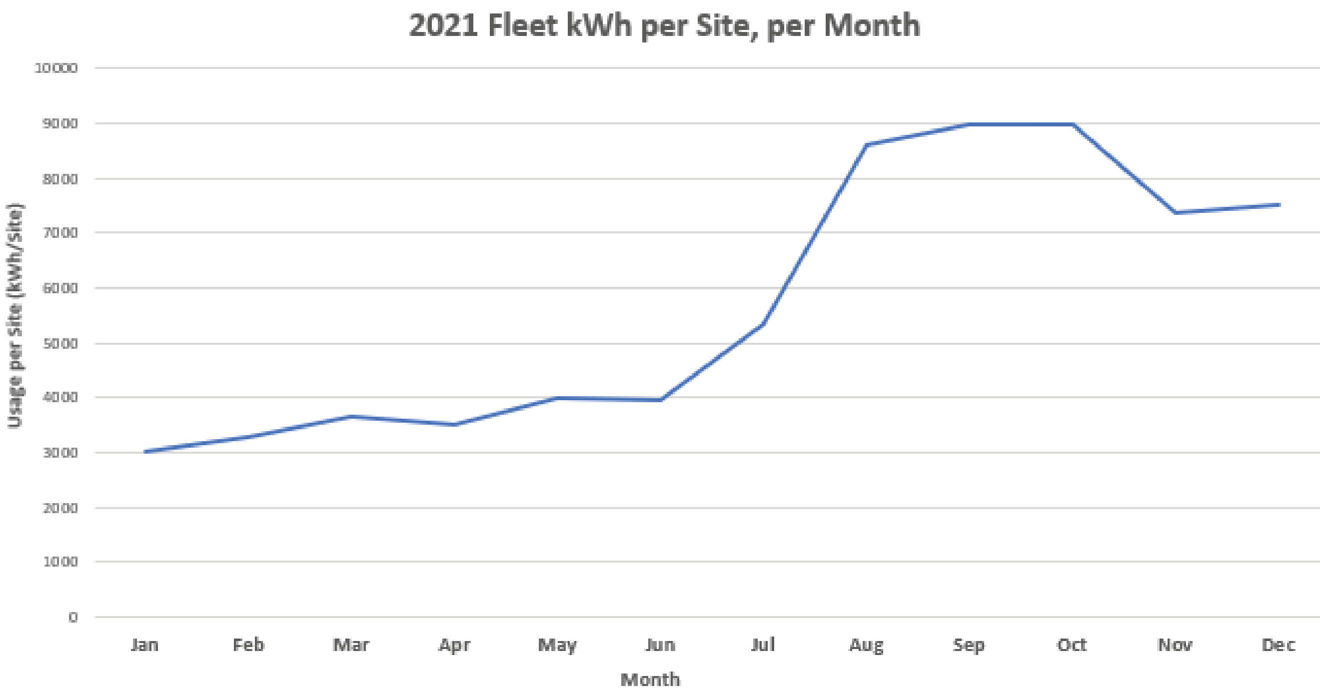
[26] Multi-dwelling units (MDUs) are defined as a residential unit with a shared wall (e.g. condo or townhouse) and are distinct from Multi-unit dwellings (MUDs) (e.g. apartment buildings), which is a term used in this report to refer to a Multi-Family Housing site that is part of a TE Program and could be enrolled in a commercial rate.

The metric displayed in the chart is defined as the average kWh/site utilized each month for the Fleet program. As seen in chart PG&E-15b, the average monthly utilization per site remained relatively low in early 2021, due to continuing COVID-19 restrictions as well as smaller Fleet sites. As 2021 progressed, the monthly utilization at an average Fleet site increased primarily to increased usage at individual sites.

Chart PG&E-15b: PG&E Fleet Program Average Monthly Usage (kWh) by Site (2021)

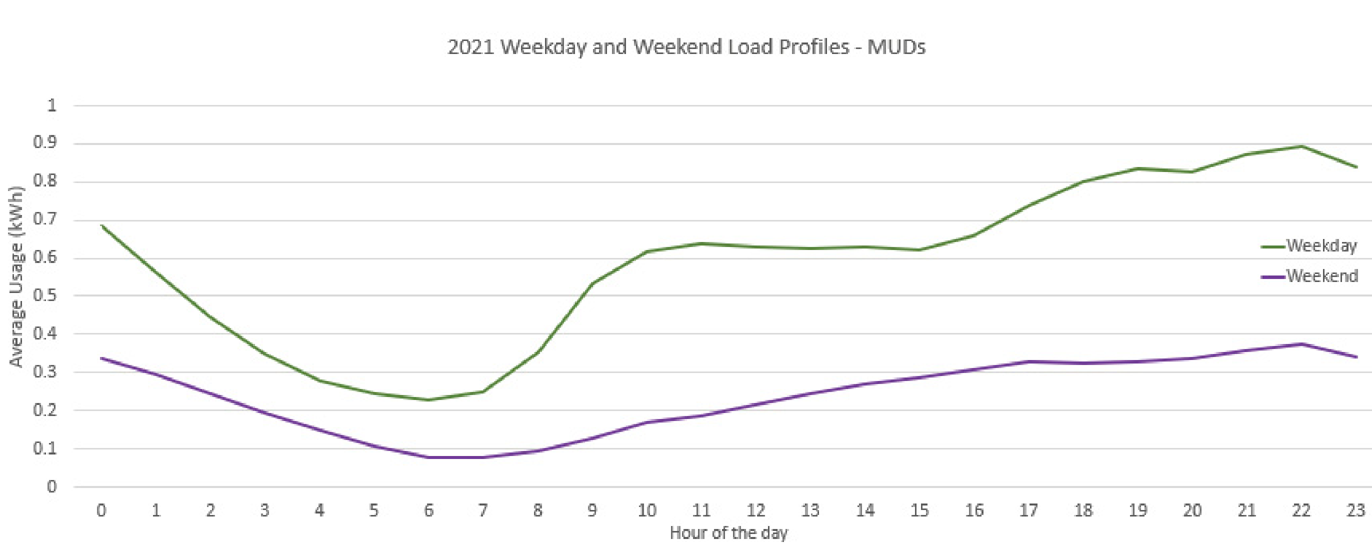


Average Load Profiles for PG&E Programs

Chart PG&E-16a shows the annual average weekday and weekend load profiles per port at MUDs in PG&E's EVCN program in 2021. Chart PG&E-16b shows the annual average weekday and weekend load profiles per port at WPs in PG&E's EVCN program in 2021. The average load profiles for usage at both MUDs and WPs showed variation throughout the day. During 2021, MUD sites experienced weekday utilization peaks between 9:00 a.m. and 3:00 p.m., as well as at the end of the day between 7:00 p.m. and midnight. In contrast, weekday utilization at WP sites, on average, experienced one large peak during the middle of the day between 9:00 a.m. and 3:00 p.m. Given that commuters most likely visit workplaces during business hours, it is sensible that utilization would peak during the middle of the day. Similarly, utilization at WP sites during the weekend peaks between the late morning and mid afternoon – 11:00 a.m. to 4:00 p.m. – as seen in Chart PG&E-16b. Ports at MUDs showed, on average, higher usage during the weekends than WPs with a peak between 4:00 p.m. and midnight. More data on PG&E's

EVCN Program can be found in the quarterly updates to the Program Advisory Council and EVCN Quarterly Reports. [27]

Chart PG&E-16a: EVCN MUD Average Weekday and Weekend Load Profile (kWh) per Port (2021)



[27] Program Advisory Council quarterly updates are publicly available here.

Chart PG&E-16b: EVCN WP Average Weekday and Weekend Load Profile (kWh) per Port (2021)

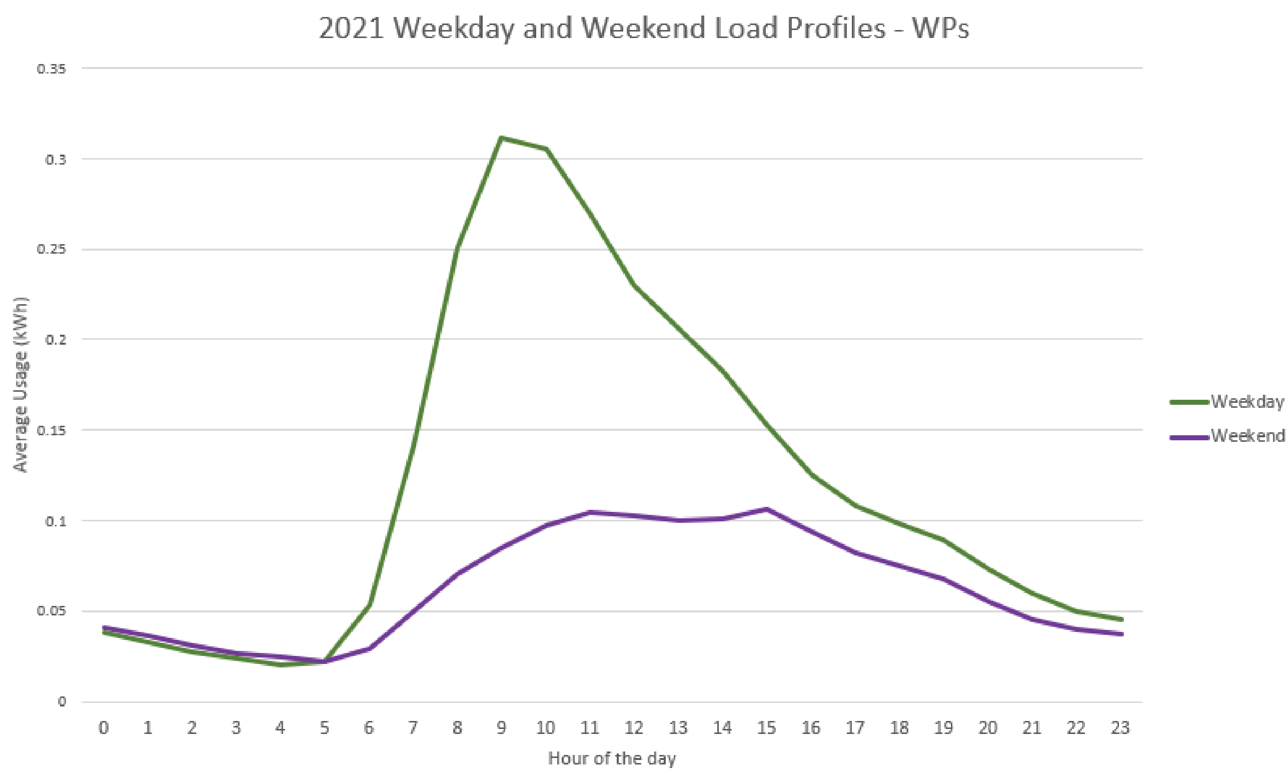


Chart PG&E-16c: EVCN WP and MUD Average Weekday and Weekend Load Profile (kWh) per Port Comparison (2021)

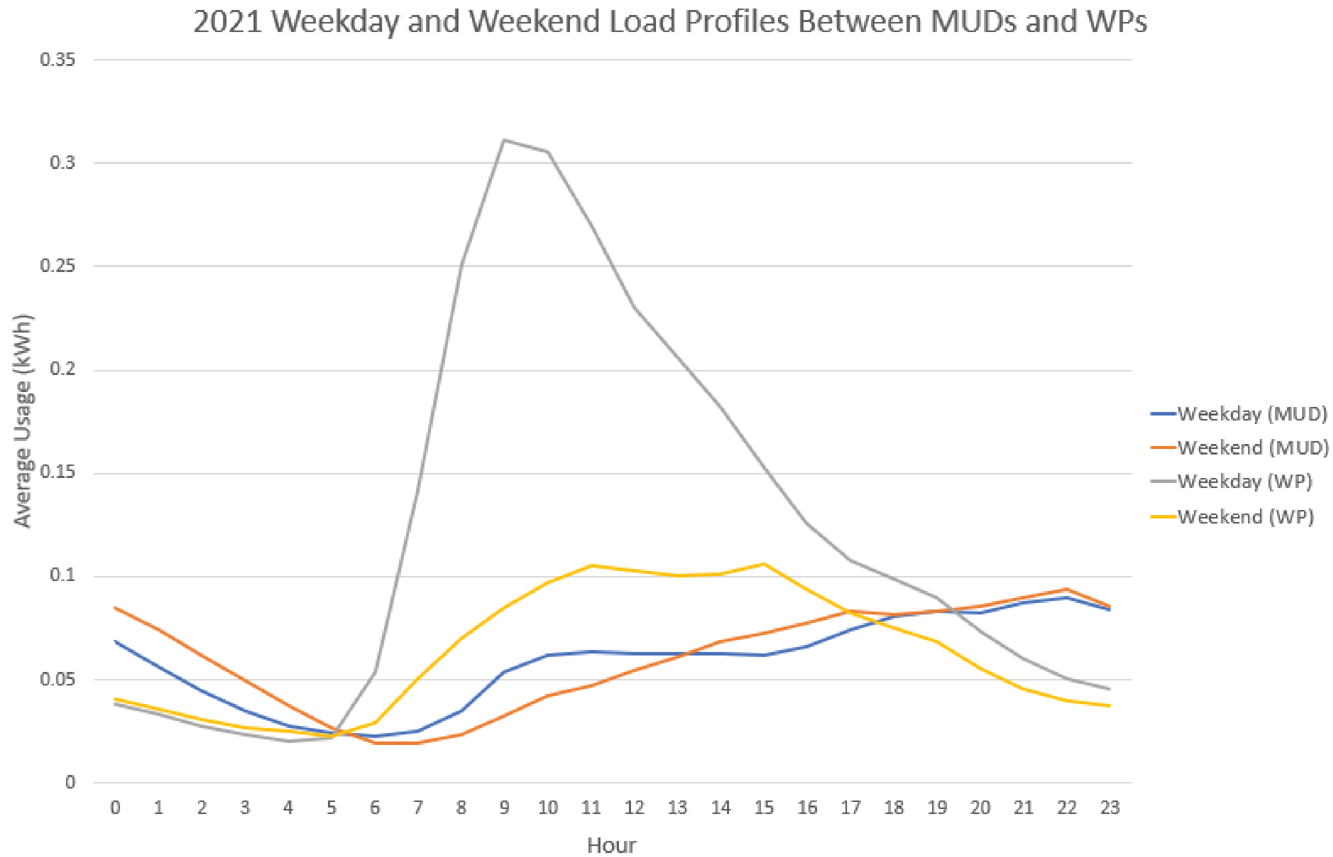
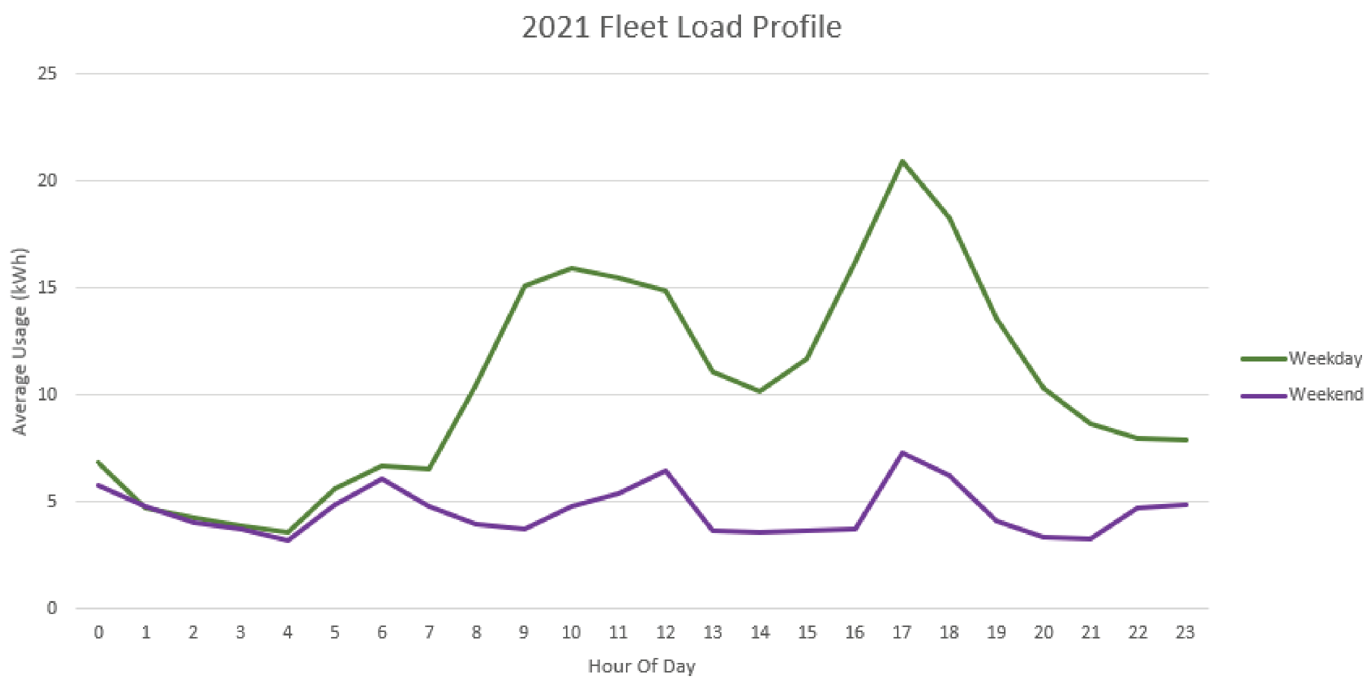


Chart PG&E-17a shows the annual average weekend load profiles for chargers at sites in the EV Fleet Program during 2021. Peak weekday utilization at Fleet sites was significantly larger than weekend utilization and occurred during two intervals. The first was between the hours of 9:00 a.m. to 12:00 p.m., and the second, larger peak was between 4:00 p.m. and 6:00 p.m. These peaks are largely driven by schools that are charging buses. Weekend charging load was much lower than weekday charging and remained relatively flat throughout the day.

Chart PG&E-17a: EV Fleet Average Weekday and Weekend Load Profile (kWh) (2021)



Average Utilization for PG&E Priority Review Projects

PG&E managed four Priority Review Projects (PRPs) including the Electric School Bus Renewables Integration Project, the Idle Reduction Technology Project, the Medium/Heavy Duty (MD/HD) Customer Fleet Demonstration Project, and the Home Charger Resource Pilot. Please see submittal of SB 350 PRP annual data report to be filed in June 2022 for detail into 2021 load data for PRP programs.

C. SCE's Load and Customer Behavior Data

This report provides data on load and utilization for customers on both residential and commercial EV specific tariffs from January 2021 to December 2021.

During the reporting period, SCE offered two rate schedules (tariffs) for residential customers designed to facilitate the charging of PEVs: (1) TOU-D-PRIME and (2) TOU-EV-1. Both schedules employ price-differentiated time-of-use periods. The TOU-D-PRIME tariff applies to both regular household loads and PEV charging loads recorded with a single meter. The time-of-use periods are designed to accommodate PEV charging requirements but apply to all household loads. The TOU-EV-1 tariff requires a second meter dedicated to measuring the electricity used at the PEV charger and the rates and time-of-use periods only apply to the electricity consumed by the PEV. PEV owners may also opt to remain on their existing tariff, likely Schedule D (domestic rate schedule). Based on the number of PEVs SCE estimates are within its service territory, the majority of PEV owners chose to remain on the domestic rate plan.[28]

The primary focus of this report is on tariffs designed with consideration for PEV charging. For commercial PEV charging, SCE offers three tariffs: TOU-EV-7, TOU-EV-8, and TOU-EV-9, which are applicable exclusively for PEV charging. The following sections report the usage characteristics from January 2021 through December 2021 for residential PEV owners identified on the TOU-D-PRIME and TOU-EV-1 tariffs and all commercial customers on TOU-EV-7, TOU-EV-8, and TOU-EV-9 tariffs.

SCE designed TOU-D-PRIME tariff to provide an attractive charging option to PEV owners. The TOU-D-PRIME tariff, however, is open to all residential customers with any of these end uses: an electric vehicle, behind-the-meter energy storage, or an electric heat pump. This means information on PEV ownership must be obtained separately. Since May 2017, SCE began accepting applications for its Clean Fuel Rebate Program (CFRP) which provides rebates to PEV owners even if they are not the original owner of that PEV. SCE's Clean Fuel Rebate Program was completed in early 2021. The California Clean Fuel Reward (CCFR) launched in November of 2020, offering an instant reduction in the purchased price of a qualifying PHEV or BEV. Both CFRP and CCFR have provided as significant source of identification of PEV owners, which were included in this analysis as of the first full month following their purchase of the PEV. Additionally, any customers who self-identified as PEV owners with SCE by providing their information through email or contact with SCE's call center before December 2018 and currently take service under TOU-D-PRIME were also included in this analysis.

Single-Metered Site Rates

Residential

The TOU-D-PRIME tariff is a single-metered TOU tariff aimed at accommodating PEV charging. TOU-D-PRIME has the same periods as SCE's TOU-D-4-9PM rate plan option, but the PRIME

[28] See Attachment 2, SCE Table 1.

option offers the lowest off-peak rates of all TOU rate plans. The price varies seasonally. As of October 2021, the latest rates within this report period, the lowest rate in the summer season was $0.194/kWh during off-peak hours and in the winter season the lowest rate was $0.186/kWh during super-off-peak hours. The tariff has a Basic Charge of $0.40/meter/day throughout the year.

The TOU periods for this tariff are defined as follows:

TOU-D-PRIME	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-peak	4 p.m. - 9 p.m.	N/A	N/A	N/A
Mid-peak	N/A	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-peak	All other hours	9 p.m. - 8 a.m.	All other hours	9 p.m. - 8 a.m.
Super-off-peak	N/A	8 a.m. - 4 p.m.	N/A	8 a.m. - 4 p.m.

Table SCE – 1a represents the price ratios of the latest rates within the reporting period that were effective October 1st, 2021.

Table SCE – 1a: Residential Single-Metered PEV Rate (TOU-D-PRIME) Price Ratios[29]

TOU-D-PRIME	Summer On-peak : Mid-peak : Off-peak	Winter Mid-peak : Off-peak : Super-off-peak
Weekday	2.5 : N/A : 1.0	2.4 : 1.0 : 1.0
Weekend	N/A : 1.9 : 1.0	2.4 : 1.0 : 1.0

[29] *See* https://www.sce.com/wps/portal/home/regulatory/tariff-books.

Separately-Metered PEV Rates

Residential

The TOU-EV-1 rate was designed for residential customers who have a separate meter solely for PEV charging. Therefore, the TOU-EV-1 rate only applies to the customer's PEV charging load. The second meter was provided and installed at no additional cost to the customer, however the home's electrical infrastructure may have needed to be upgraded with a second panel and wiring to the charging location. Any costs related to the changes to the home's electrical infrastructure were the responsibility of the customer. For this rate plan, lower rates apply during off-peak hours of 9:00 p.m. to 12:00 noon, and rates change seasonally. For usage between noon and 9 p.m., rates are higher in summer. The following are the TOU periods for the separately-metered rate:

On-peak	12:00 noon – 9:00 p.m., daily
Off-peak	All other hours.

The TOU-EV-1 tariff was closed to new customers as of March 1st, 2019. Existing customers were, however, permitted to continue taking service on this tariff. On February 1st, 2021, this tariff was temporarily reopened to multifamily accommodations until implementation of SCE's 2021 General Rate Case Phase 2 Decision which is still pending.

The relevant price ratios (effective October 1st, 2021) are reported in the following table, Table SCE – 1b.

Table SCE – 1b: Residential Separately-Metered PEV Rate (TOU-EV-1) Price Ratios

TOU-EV-1	Summer On-peak : Off-peak	Winter On-peak : Off-peak
Daily	3.7 : 1.0	2.1 : 1.0

Commercial

Three rate options (tariffs) are available to commercial customers that separately meter the charging of PEVs. TOU-EV-7, TOU-EV-8, and TOU-EV-9 tariffs are available depending on the expected size of the maximum demand. TOU-EV-7 is applicable to customers with charging demands less than 20 kW; TOU-EV-8 is applicable to customers with charging demands equal to or more than 20 kW but less than 500 kW; and TOU-EV-9 is applicable to customers with charging demands of 500 kW and greater.

To facilitate the growth of PEV charging at these sites, these tariffs only have energy rates. They also include a customer charge. All these tariffs have the same TOU periods as our residential TOU-D-PRIME rate option shown in the above section. The prices vary seasonally and between tariffs. Beginning on March 1st, 2024, Facilities Related Demand Charges and Time-related Demand charges will be phased in over five years.

Table SCE – 1c, 1d and 1e represent the price ratios for energy of each commercial PEV rate effective October 1st, 2021. The associated customer charges as of October 1st, 2021 were: \$0.555/meter/day for TOU-EV-7; \$194.05/meter/month for TOU-EV-8; and \$701.42/meter/month (below 2 kV), \$373.12/meter/month (2 kV to 50 kV), \$2586.55/meter/month (above 50 kV) for TOU-EV-9.

Table SCE – 1c: Commercial PEV Rate (TOU-EV-7) Price Ratios

TOU-EV-7	Summer On-peak : Mid-peak : Off-peak	Winter Mid-peak : Off-peak : Super-off-peak
Weekday	2.8 : N/A : 1.0	3.9 : 1.6 : 1.0
Weekend	N/A : 2.2 : 1.0	3.9 : 1.6 : 1.0

Table SCE – 1d: Commercial PEV Rate (TOU-EV-8) Price Ratios

TOU-EV-8	Summer On-peak : Mid-peak : Off-peak	Winter Mid-peak : Off-peak : Super-off-peak
Weekday	3.8 : N/A : 1.0	4.1 : 1.7 : 1.0
Weekend	N/A : 2.3 : 1.0	4.1 : 1.7 : 1.0

For customers with demand of 500 kW and above, rates are further differentiated by the service voltage level.

Table SCE – 1e: Commercial PEV Rate (TOU-EV-9) Price Ratios

TOU-EV-9	Summer On-peak : Mid-peak : Off-peak	Winter Mid-peak : Off-peak : Super-off-peak
(Below 2 kV)		
Weekday	3.9 : N/A : 1.0	4.0 : 1.6 : 1.0
Weekend	N/A : 2.3 : 1.0	4.0 : 1.6 : 1.0
(2 kV to 50 kV)		
Weekday	3.9 : N/A : 1.0	3.8 : 1.5 : 1.0
Weekend	N/A : 2.3 : 1.0	3.8 : 1.5 : 1.0
(Above 50 kV)		
Weekday	3.5 : N/A : 1.0	2.6 : 1.4 : 1.0
Weekend	N/A : 1.5 : 1.0	2.6 : 1.4 : 1.0

NEM Program Enrollment

The Net Energy Metering (NEM) tariff provides compensation for customers with distributed generation resources such as photovoltaic solar systems. The energy produced by these systems may be consumed on-site and excess generation is exported to the grid. This reduces the amount of energy purchased from the grid. As shown in Table SCE – 2a, the coincidence of PEV ownership and enrollment in the NEM rate option was 27% from April to November but dropped to 21% in December on the current, whole-house TOU-D-PRIME tariff.

Table SCE – 2a: NEM Program Enrollment for Residential Single Metering by Customer Type

Month	NEM Customers with Single Metering	NEM as % Single Metering	NEM as % SF Single Metering	NEM as % MDU Single Metering
Jan. 2021	3,401	25%	28%	8%
Feb. 2021	3,595	25%	28%	9%
Mar. 2021	3,890	26%	29%	9%
Apr. 2021	4,128	27%	30%	9%
May. 2021	4,286	27%	30%	9%
Jun. 2021	4,486	27%	30%	9%
Jul. 2021	4,651	27%	30%	9%
Aug. 2021	4,949	27%	31%	9%
Sep. 2021	5,351	27%	31%	9%
Oct. 2021	5,730	27%	31%	9%
Nov. 2021	6,175	27%	30%	9%
Dec. 2021	6,715	21%	23%	7%

There are fewer than fifteen separately-metered residential customers enrolled in the NEM program, therefore no data is reported for Table SCE – 2b: NEM Program Enrollment for Residential Separate Metering.

There is no NEM participation on commercial PEV tariffs TOU-EV-7. During this reporting period, only a couple TOU-EV-8 and TOU-EV-9 customers were enrolled in the NEM program

Number of PEV Time-of-Use Accounts

SCE's residential single-metered rate option is open to all residential customers and therefore it is necessary to independently identify which customers own PEVs. SCE leveraged its Clean Fuel Rebate program and California Clean Fuel Reward program, which were funded by Low Carbon Fuel Standard credit revenues, to identify customers with EVs. Prior to 2019, some PEV owners were also identified through the California Air Resources Board's California Clean Vehicle Rebate Project. Additionally, customers previously on the, now closed, TOU-D-TEV tariff were included. This tariff was exclusive to PEV owners. For most customers, the date of PEV acquisition is not known. This report includes any owners of vehicles where the model year of their vehicle is older than the current year. As such, 2021 statistics include any accounts with PEVs from model year 2020 or older.

TOU-D-PRIME became available to customers in March 2019. Since then, there has been a consistent increase in the number of accounts with PEVs for both single-family and multi-family units as can be seen in Chart SCE – 1. It is not known if this trend reflects growth in the overall market or other factors that may influence the rates of self-identification (e.g. rebate incentives, tarriff changes, propensities to contact the Call Center, utility or industry marketing efforts, new vehicle models with different specifications, etc.). As of December 2021, SCE has identified 32,380 single-metered PEV owners, of which 85 percent were single-family units. The jump in the number of accounts in December 2021 was largely attributed to SCE's residential TOU default implementation.

Chart SCE – 1: Residential Single Meter (TOU-D-PRIME) – Number of Accounts by Customer Type at the Beginning of Each Month

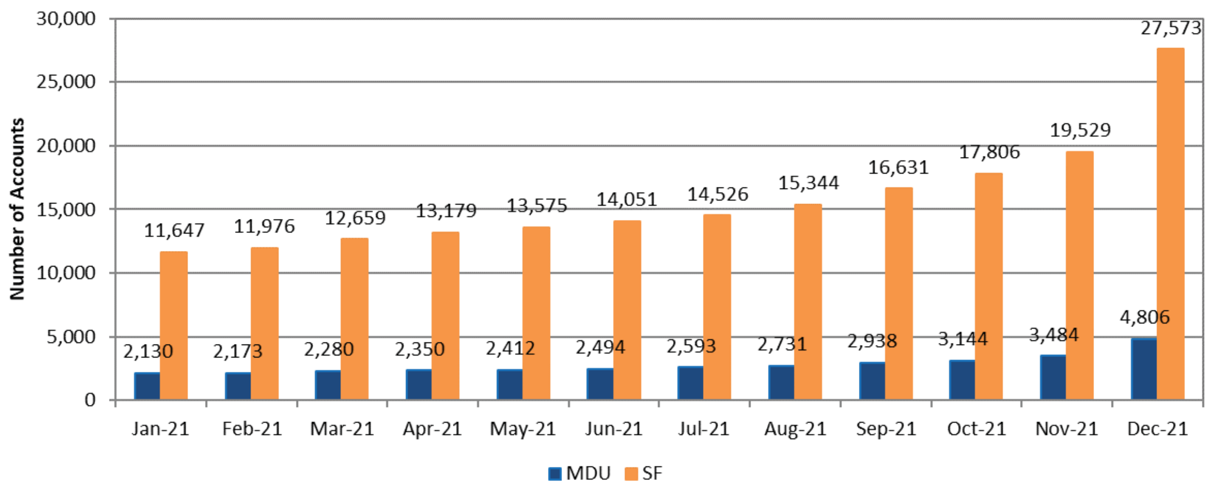


Chart SCE – 2a shows a slight downward trend of separately-metered accounts (TOU-EV-1) over this reporting period but the total remains at 695 as of December 2021. Beginning in March 2019, TOU-EV-1 was closed to new customers. With single-family customers only able to depart this tariff option, the customer account has decreased slightly over time. The number of TOU-EV-1 accounts reported here are only the accounts which register charging during the month. There are some active accounts which persistently have zero usage. This could occur if the location is not a primary residence or if there was a change of ownership and the PEV is no longer present. It could also occur if all the charging is done away from the residence.

Chart SCE – 2a: Residential Separate Meter (TOU-EV-1) – Number of Accounts at the Beginning of Each Month

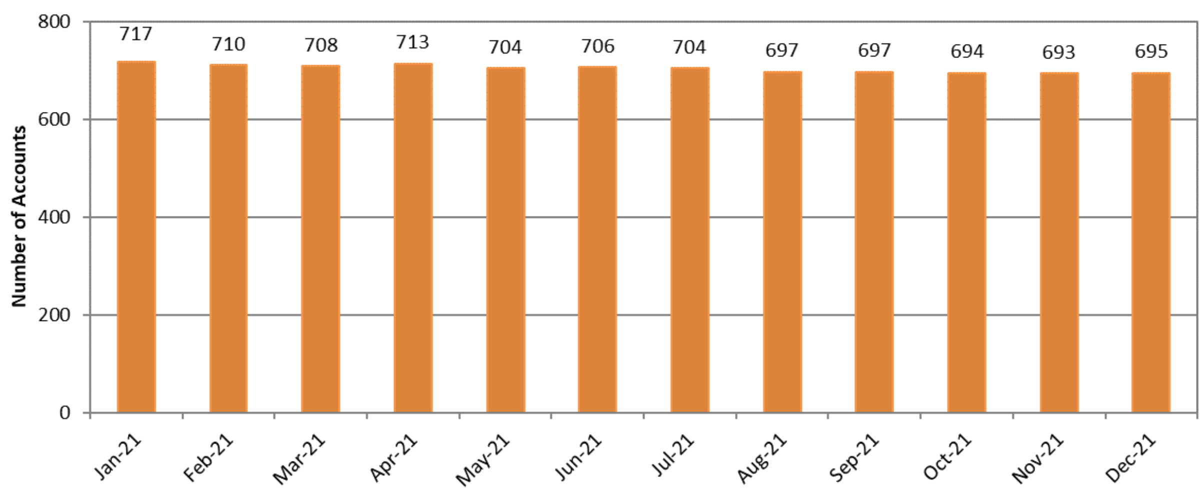
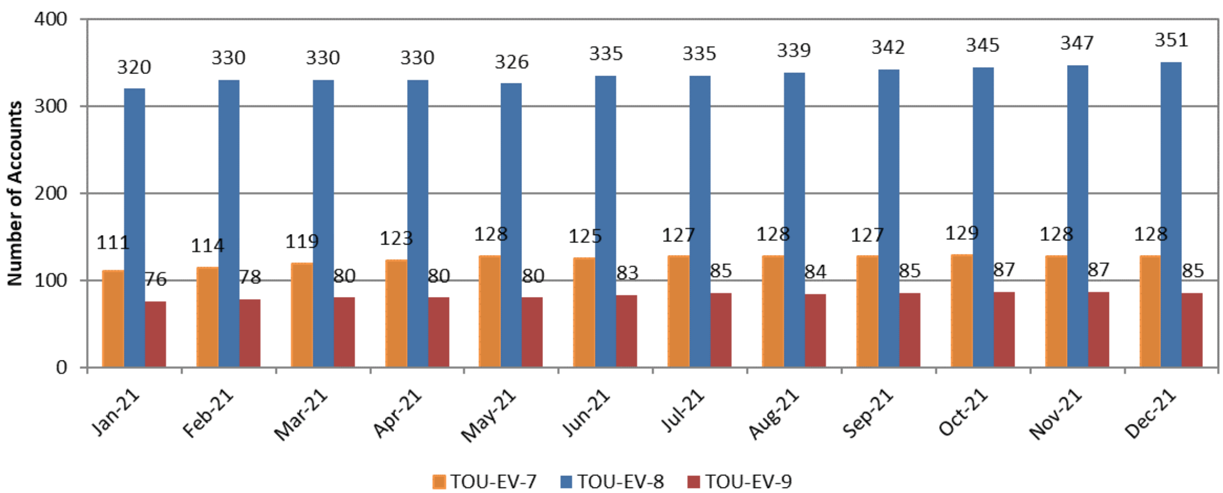


Chart SCE – 2b reflects the steady upward trend of commercial, separately-metered accounts. As of December 2021, there were 128 customers served on TOU-EV-7 tariff, 351 customers served on TOU-EV-8, and 85 customers served on TOU-EV-9. Demand for commercial TOU-EV rates has been boosted by SCE's PEV programs which invest in PEV charging infrastructure. The growth rate is the greatest forTOU-EV-7 during 2021.

The number of the customers reported here are only the accounts which registered charging during the month. Similar to the case with TOU-EV-1, there are a number of accounts which have zero usage. This might occur when the account is first established but has not yet started charging PEVs or does not have any PEV charging due to various other reasons. For example, a business that was temporarily closed down due to the COVID-19 pandemic may have zero usage.

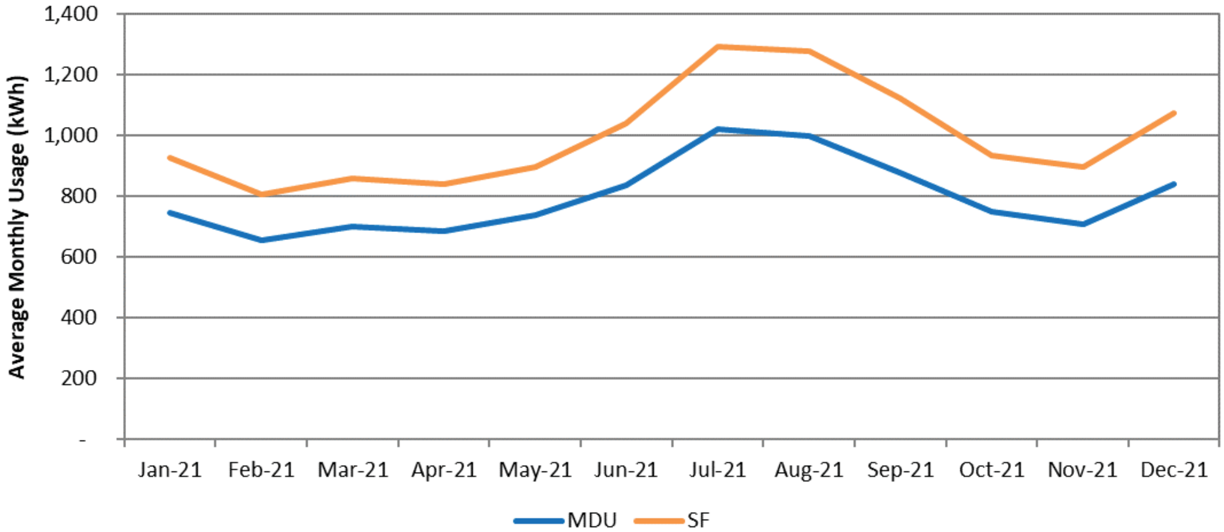
Chart SCE – 2b: Commerical Separate Meter – Number of Accounts at the Beginning of Each Month



Average Monthly Usage for TOU Accounts with a PEV

The average monthly household usage for single-metered households with a PEV shown in Chart SCE – 3 depicts the same seasonal pattern as in previous years as well as very similar usage levels. Single-family dwellings have 25 percent more usage than multi-family units but the same pattern over the course of the year with the lowest usage occuring February through May, and again in November. July to September have the highest usage for single-metered households. This is the typical seasonal behavior of residential households, which is primarily driven by cooling. The greatest average usage during the twelve months occurred in July 2021 at 1,292 kWh for SF and at 1,020 kWh for MDU.

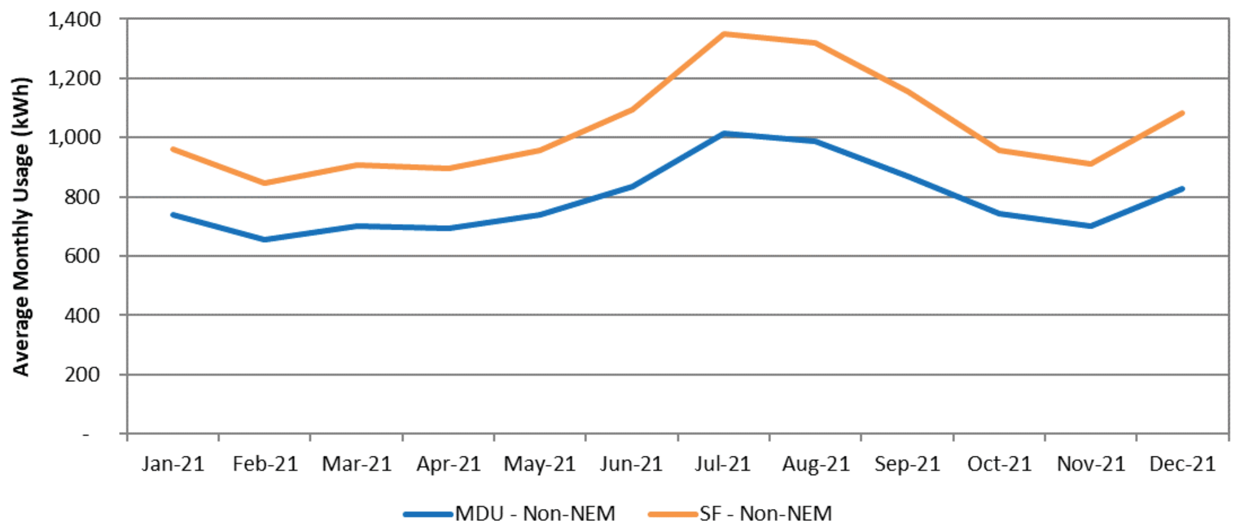
Chart SCE – 3: Residential Single Meter (TOU-D-PRIME) – Average Monthly Usage (kWh) by Customer Type Including NEM



Excluding NEM accounts has very little impact on the average monthly usage of PEV owners, as seen in Chart SCE – 4. The annual monthly usage pattern remains identical to what is shown in Chart SCE – 3. The usage is slightly higher when NEM accounts are excluded, indicating that the NEM households with PEVs take less electricity from the grid than the non-NEM PEV owners. The small impact is in part the result of the relatively small percentage of NEM accounts. Also, the average monthly usage for NEM households is only the energy that is delivered by SCE, not the total consumption or the delivered energy net of exports. If NEM households have higher consumption than non-NEM households, then the balance of their consumption served by SCE might be similar between the two groups. This would also explain why the average monthly usage changes very little when NEM households are excluded.

If non-coincident demand were used as an indication of consumption, the non-coincident demands for NEM households with PEVs are higher than the average household. Non-coincident demands for all single-meter PEV owners are presented in Table SCE – 9 and discussed in greater detail below. However, it is worth pointing out that the monthly average non-coincident demands for NEM households range from 8.4 kW to 10.5 kW, indicating that demands for the NEM households with a PEV are about 1.0 kW larger than the average household with a PEV.

Chart SCE – 4: Residential Single Meter (TOU-D-PRIME) – Average Monthly Usage (kWh) by Customer Type Excluding NEM



The average monthly usage displayed in Chart SCE – 5a for separately-metered PEVs has been recovering from impacts resulting from the COVID-19 pandemic and has crept up close to 350 kWh per month. The consistent usage observed by the separately-metered PEVs supports the presumption that the seasonal trends seen in the household usage of single-metered PEV owners is not the result of PEV charging.

Chart SCE – 5a: Residential Separate Meter (TOU-EV-1) – Average Monthly Usage

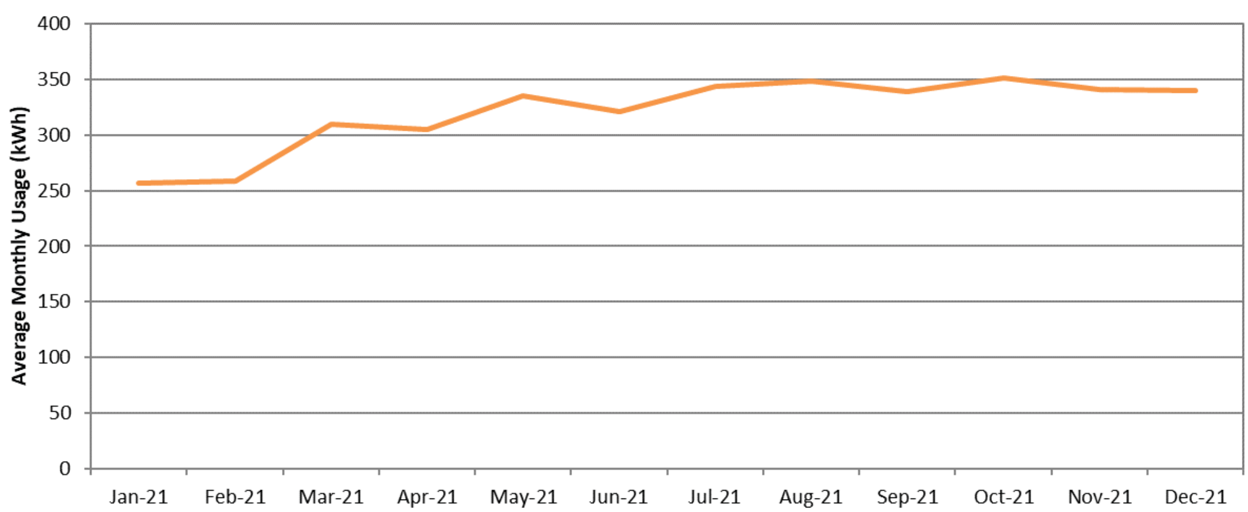


Chart SCE – 5b depicts an upward trend in average monthly usage for commercial separately-metered TOU-EV-7. The drop in average monthly usage observed in January 2021 from December 2020 was caused by a couple of accounts which migrated into TOU-EV-8 or TOU-EV-9. A steep increase in average monthly usage occurred in February and March 2021, presumably driven by the increased outdoor activities after the lift of statewide Limited and Regional Stay Home order in the end of January 2021. Since then, the average monthly usage appears to have crept upwards of 700 kWh, which is the same level as the pre-pandemic average in February 2020.

Chart SCE – 5b: Commercial Separate Meter (TOU-EV-7) – Average Monthly Usage

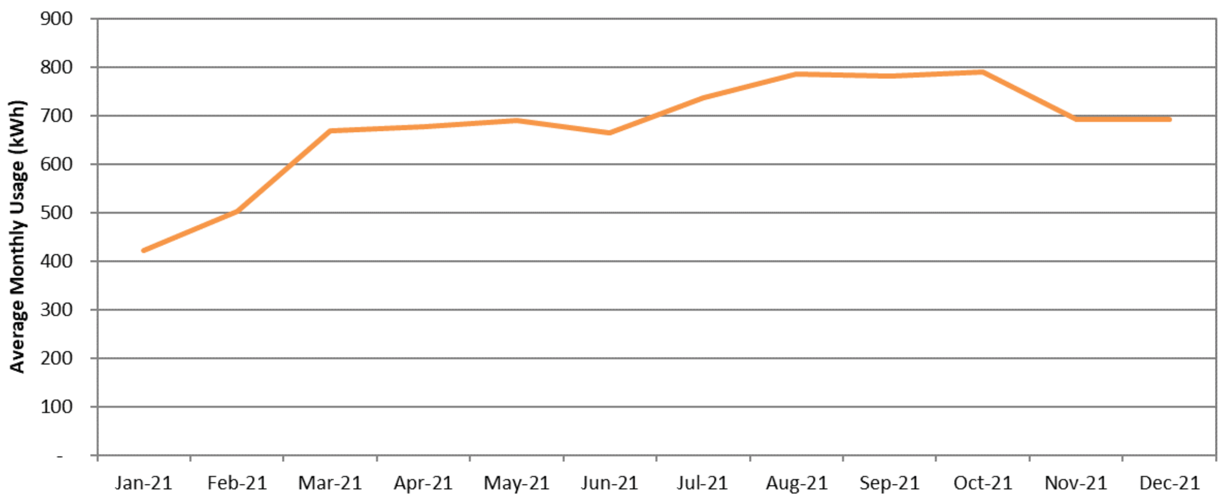
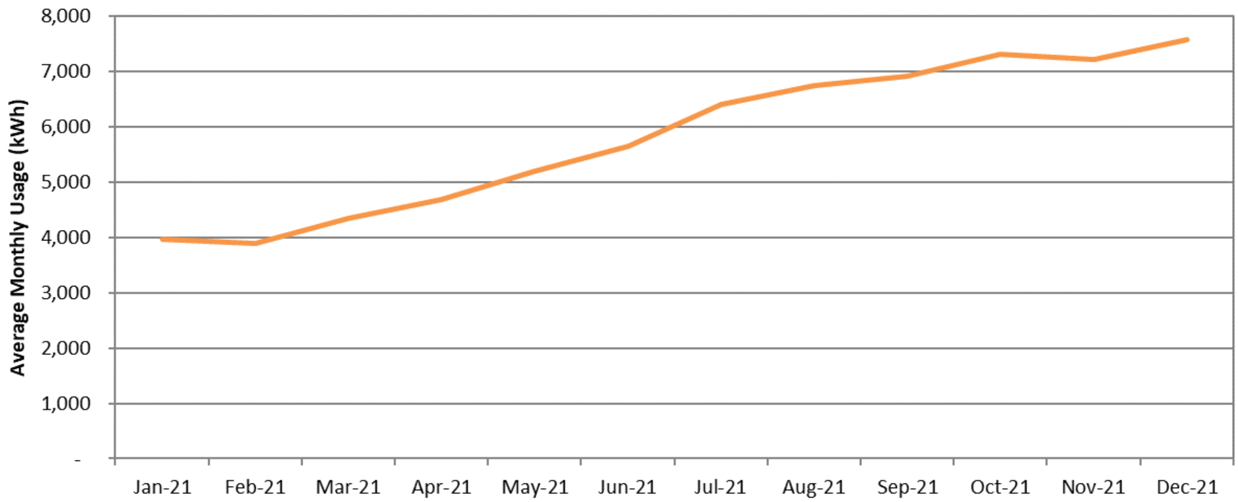


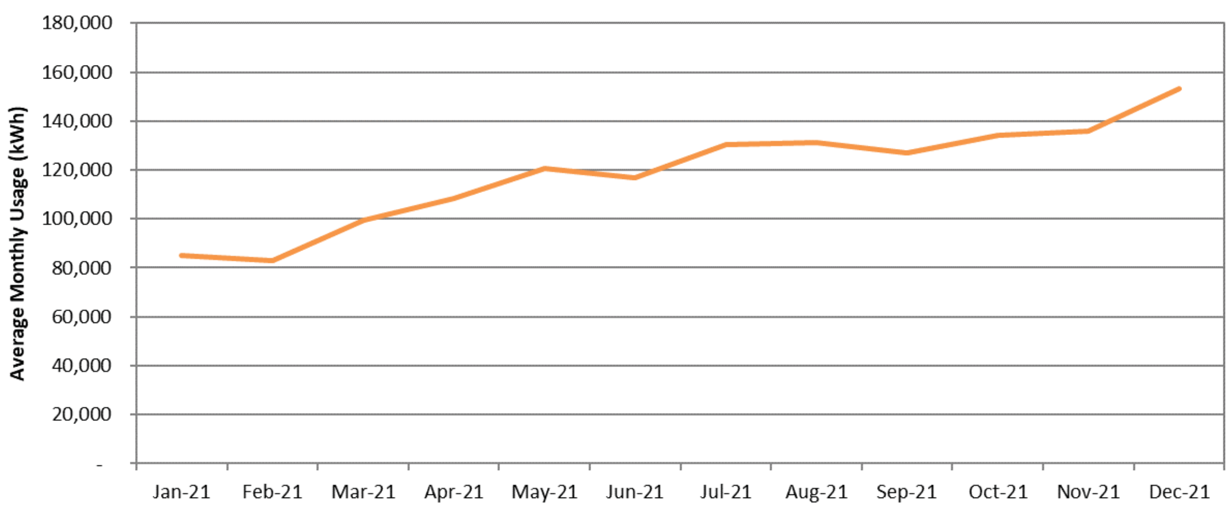
Chart SCE – 5c depicts a growing average in monthly usage for commercial separately-metered TOU-EV-8. In July 2021, the average monthly usage reached over 6,000 kWh and surpassed pre-pandemic level in February 2020. It continues to increase and hit the highest average monthly usage at 7,581 kWh in December 2021.

Chart SCE – 5c: Commercial Separate Meter (TOU-EV-8) – Average Monthly Usage



The average monthly usage for commercial, separately-metered TOU-EV-9 shown in Chart SCE-5d, displays a similar growing trend as that for TOU-EV-8. It continues to recover from the COVID-19 policy impacts and surpassed the pre-pandemic average in February 2020. The average monthly usage peaked at 153,242 kWh as of December 2021.

Chart SCE – 5d: Commercial Separate Meter (TOU-EV-9) – Average Monthly Usage



Average Usage during Time-of-Use Periods

Some of the subsequent load profiles and usage characteristics will also include the average residential customer as a benchmark for the single-metered PEV customers. This data is derived from SCE’s 2020 Domestic Rate Group Load Study, which is based on the 2020 calendar year.

Tables SCE – 3, 4, 5, and 6 each show the proportion of seasonal usage by time-of-use period for single-metered households. PEV owners have the greatest share of their usage within the off-peak window of the TOU-D-PRIME tariff as shown in Table SCE – 5. In summer 2021, 78 percent of usage by PEV owners without NEM occurred during off-peak hours and in winter 2021, the amount of usage is 52 percent. Both are significantly higher than proportion of usage by the general residential population during off-peak hours at 69 percent and 41 percent, respectively. From Table SCE – 3 to 6, all groups have the lowest proportion of usage occurring in mid-peak hours.

Table SCE – 3: Residential Single Meter (TOU-D-PRIME) – On-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2021	22.0%	15.6%	15.6%	15.2%	16.2%
Winter 2021	N/A	N/A	N/A	N/A	N/A
* On-peak period is defined as 4:00 p.m. - 9:00 p.m., Summer weekdays.					

Table SCE – 4: Residential Single Meter (TOU-D-PRIME) – Mid-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2021	9.2%	6.7%	6.7%	6.5%	7.0%
Winter 2021	27.3%	19.4%	19.5%	19.1%	20.4%
* Mid-peak period is defined as 4:00 p.m. - 9:00 p.m., Weekends/Holidays, all year; and 4:00 p.m. - 9:00 p.m., Winter Weekdays.					

Table SCE – 5: Residential Single Meter (TOU-D-PRIME) – Off-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2021	68.8%	77.7%	77.6%	78.3%	76.8%
Winter 2021	40.5%	51.6%	51.4%	53.0%	64.7%
* Off-peak period is defined as all other hours that are not On-peak, Mid-peak, or Super-Off-peak.					

Table SCE – 6: Residential Single Meter (TOU-D-PRIME) – Super-Off-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2021	N/A	N/A	N/A	N/A	N/A
Winter 2021	32.1%	29.0%	29.1%	27.9%	14.9%
* Off-peak period is defined as 8:00 a.m. - 4:00 p.m., Winter daily.					

PEV owners with a separate meter for their vehicle on average charge 83 percent of their usage during the off-peak period in 2021 as shown in Table SCE – 7. The proportion of seasonal usage by time-of-use period for separately-metered households were the same in summer and winter.

Table SCE – 7: Residential Separate Meter (TOU-EV-1) – Usage During Time-of-Use Periods

Season	On-peak	Off-peak
Summer 2021	16.8%	83.2%
Winter 2021	16.8%	83.2%

Tables SCE – 8a, 8b, and 8c show the proportion of seasonal usage by time-of-use period for each of the commercial, separately-metered rate options. Each table shows a similar usage pattern, in which the greatest share of their usage falls within the lowest rate window.

In summer, TOU-EV-7 charges 77 percent on average during the off-peak window; TOU-EV-8 and TOU-EV-9 charge slightly, 71 percent and 69 percent, respectively. In winter, each group of commercial, separately-metered customers charge over 47 percent during the super off-peak window on average. Nonetheless, this does not necessarily lead to the conclusion that customers on commercial PEV rates are responsive to the TOU price signals, because most charging stations and public facilities do not differentiate TOU prices for individual users.

Table SCE – 8a: Commercial Separate Meter (TOU-EV-7) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2021	17.2%	5.8%	77.0%	N/A
Winter 2021	N/A	24.4%	26.9%	48.7%

Table SCE – 8b: Commercial Separate Meter (TOU-EV-8) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2021	21.1%	8.0%	70.9%	N/A
Winter 2021	N/A	28.0%	24.6%	47.4%

Table SCE – 8c: Commercial Separate Meter (TOU-EV-9) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2021	21.1%	9.9%	69.0%	N/A
Winter 2021	N/A	30.2%	21.2%	48.5%

Average Load Profiles - Residential

Average hourly load profiles provide a clear visual depiction of the daily usage patterns. Load profiles are shown on the same chart for single- and multi-family dwellings. Additionally, average hourly load profiles are shown by day type for accounts which self-identified with SCE as PEV owners and remain on the regular domestic, Schedule D, tariff.

The load profiles for single-family and multi-family households with a PEV that opted for the TOU-D-PRIME tariff are shown in Chart SCE – 6. As is typical with residential annual average hourly usage, usage peaks in the evening around 8:00 p.m. Mid-day usage is lower every day, but not quite as low on the weekend as on weekdays. Rather than declining into the morning hours, however, these profiles exhibit a large spike beginning at 10 p.m. and peaking at 11 p.m. before tapering until 6:00 a.m. For SF customers, the peak of the weekday spike averages 2.29 kW, 50% greater than the 1.53 kW average usage at 8:00 p.m. The beginning of the spike at 10 p.m. corresponds directly with the off-peak time period of the TOU-D-PRIME tariff and is abnormal for typical residential customers. The peak is likely attributable to PEV charging; however, the observed usage includes all household loads during these hours. Nearly identical behavior is observed with MDU customers in the same Chart SCE – 6, with the exception that the average hourly usage is lower, peaking at 1.79 kW on weekdays. Altogether it appears that the PEV owners who choose a TOU rate for their household and PEV electricity needs are very responsive to the TOU period prices.

Chart SCE – 6: Residential Single Meter (TOU-D-PRIME), Average Hourly Load Profile by Day Type

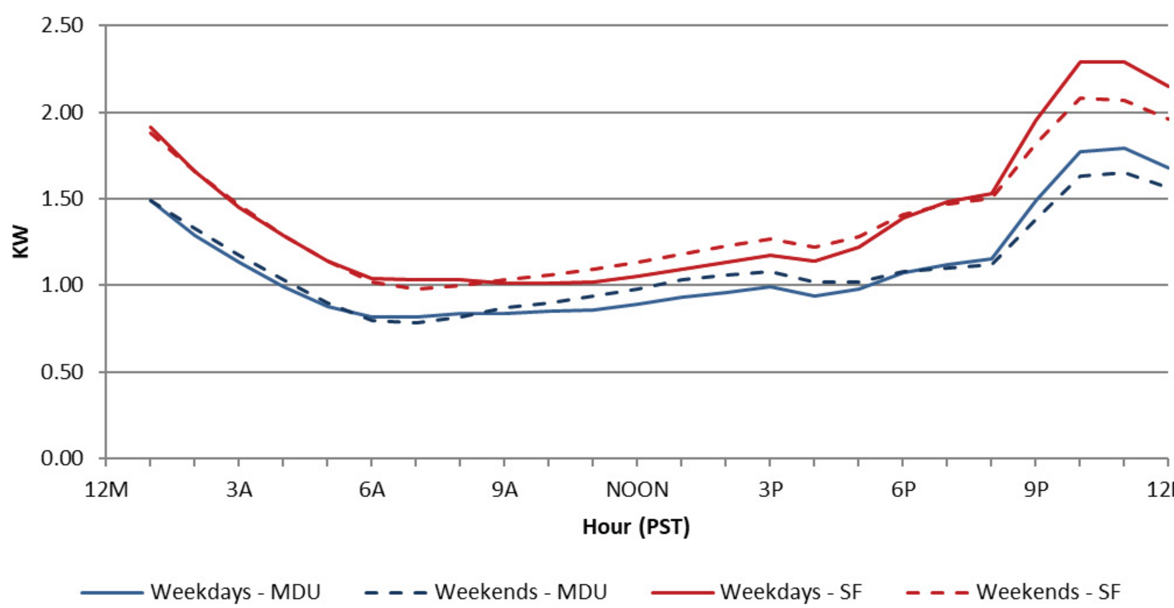


Chart SCE-7 shows that separately-metered PEVs commence charging promptly at the beginning of the off-peak period around 9:00-10:00 p.m. After 12:00 a.m., demands begin to taper off as vehicles reach full charges. The highest demand occurs on weekdays and has an average hourly demand of 1.2 kW. Weekend peak demand is around 1.0 kW. Charging during the day between 6:00 a.m. and 8:00 p.m. is very low.

Chart SCE – 7: Residential Separate Meter (TOU-EV-1) - Average Hourly Load Profile by Day Type

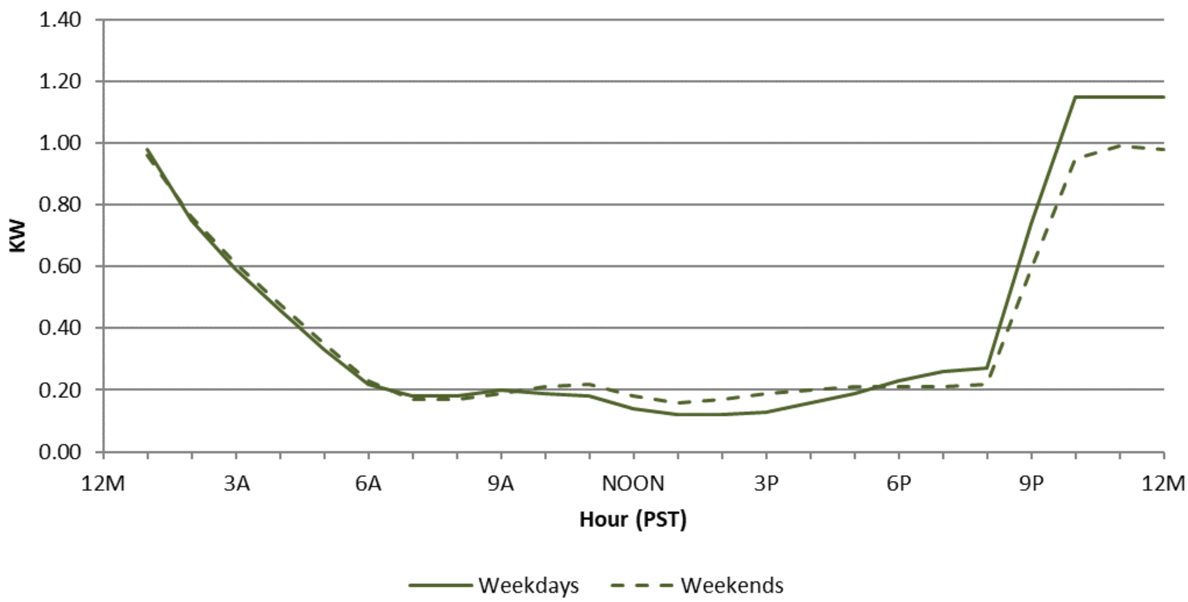
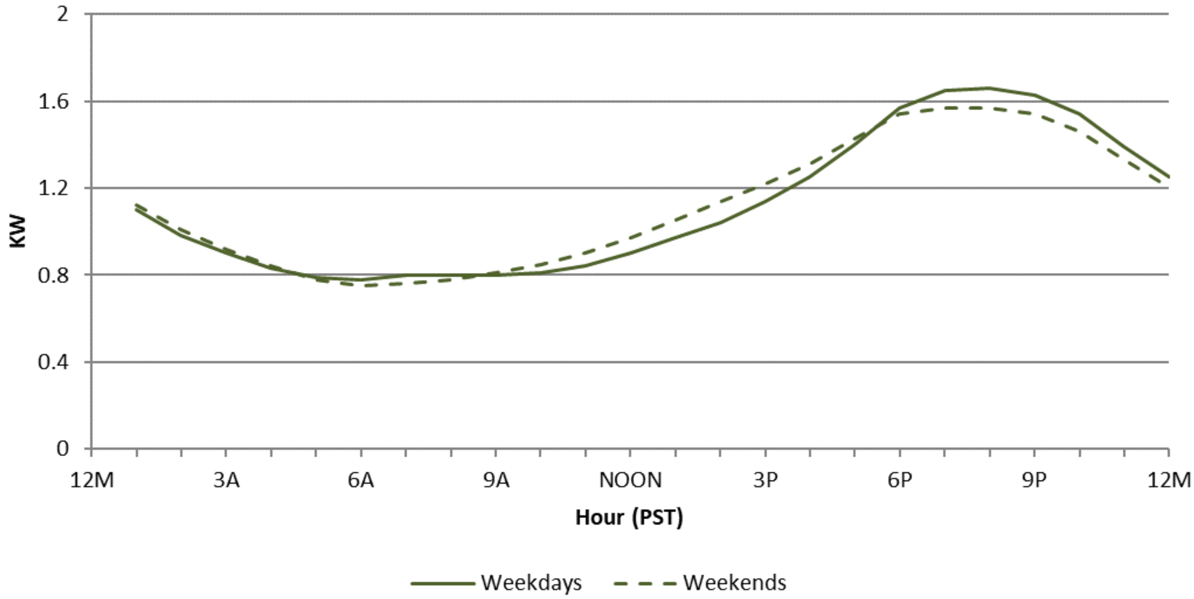


Chart SCE – 8 shows the load profile for a portion of the SF customers who are believed by SCE to own a PEV but choose to remain on the regular, tiered domestic rate. Their daytime demand begins to rise around 10:00 a.m. where it is 0.8 kW on weekdays and increases gradually until it peaks in the evening at 8:00 p.m. at about 1.7 kW on average. Weekend loads are slightly higher during the middle of the day but notably have lower evening peak loads. Late evening loads are also lower presumably due to less PEV charging. As compared to the single-family, single-metered TOU customers in Chart SCE – 6, these non-TOU customers lack the larger peak occurring at midnight.

Chart SCE – 8: Residential Single Meter, SF PEV Owners[30] on a Non-TOU Rate – Average Hourly Load Profile by Day Type



[30] As of December 2021, there were 54,640 accounts, on the Domestic rate schedule (including NEM customers) with load data, which are known to own a PEV.

Average Load Profiles - Commercial

Chart SCE – 9a shows the load profile for commercial separately-metered TOU-EV-7. The average weekday demand begins to rise around 5:00 a.m. where it is 0.3 kW and steeply boosts up to the peak around 10:00 a.m. with an average demand of 1.7 kW, before tapering off for the rest of the day. Weekday daily usage is 23 kWh on average, 36 percent more than weekend daily usage. On the other hand, the weekend profile before 5:00 a.m. almost overlaps with the weekday profile, however, unlike the weekday load which spikes in the morning, weekend load displays a shape like a downward parabola from 6:00 a.m. to the midnight with the peak demand of 1.1 kW occurring around 3:00 p.m.

Chart SCE – 9a: Commercial Separate Meter (TOU-EV-7) - Average Hourly Load Profile by Day Type

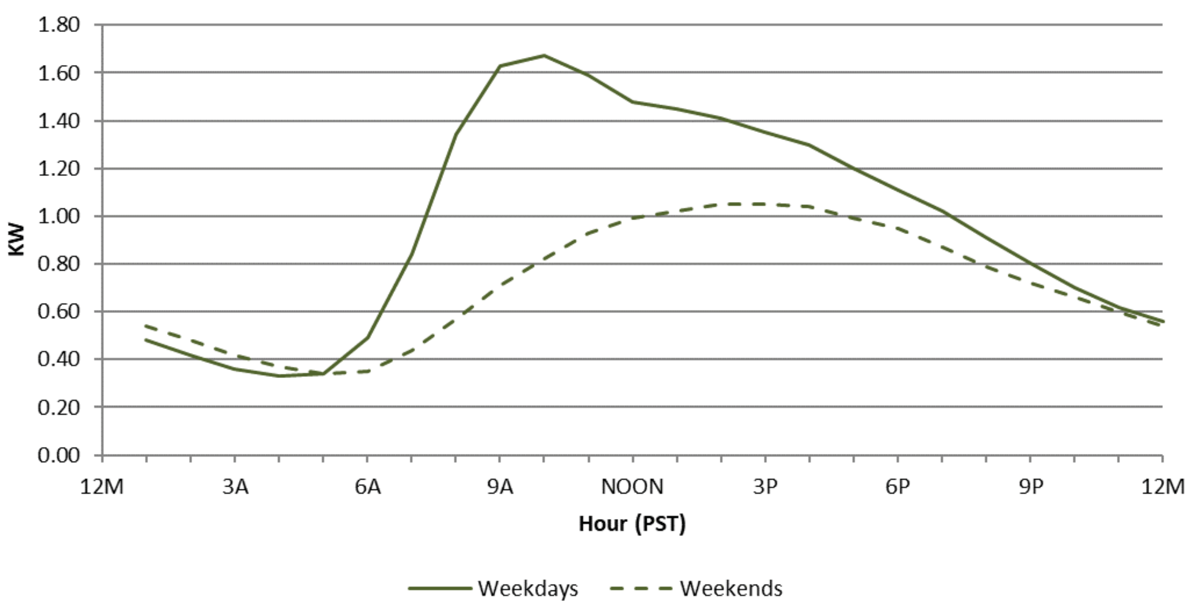
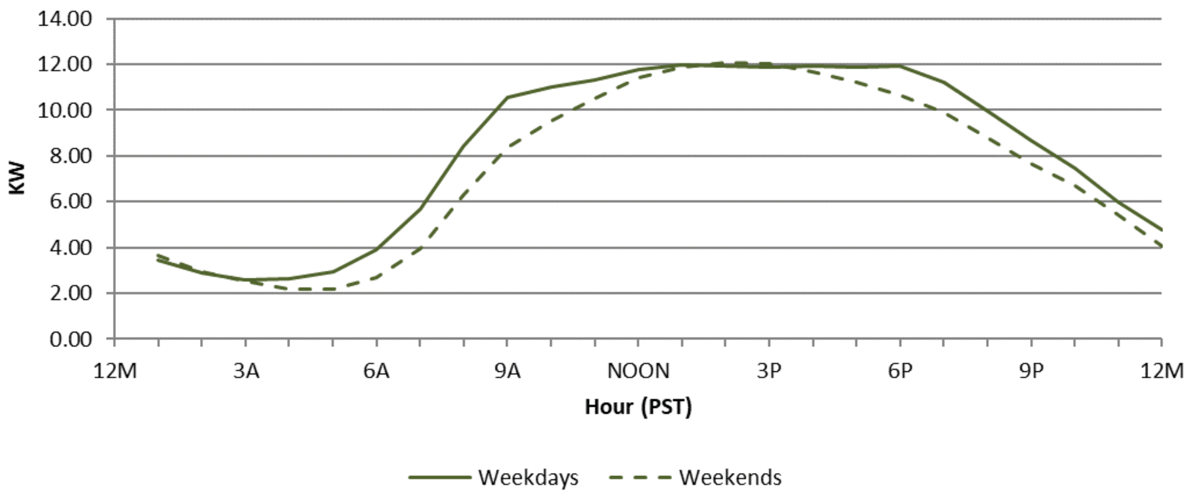


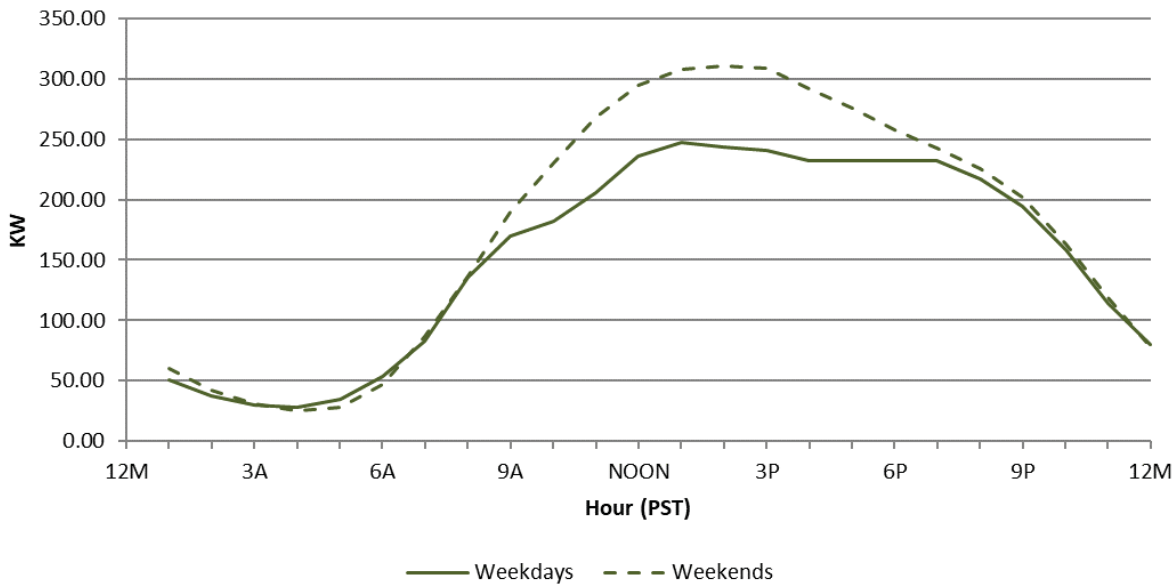
Chart SCE – 9b provides average weekday and weekend hourly load profiles for customers on separately-metered TOU-EV-8. The average weekday demand begins to rise around 5:00 a.m. where it is about 3 kW and reaches inflection at 9:00 a.m. with an average demand of 11 kW. The demand remains near 12 kW until 6:00 p.m. From there it tapers off for the rest of the day. TOU-EV-8 consists of different business types with different load characteristics. Morning load peak is more likely driven by workplaces and school districts, whereas charging networks and destination centers demand more at a later time. Together they maintain the level of load demand and depict a nearly flat load shape during the daytime. Weekend demand also begins to rise around 5:00 a.m. where it is about 2 kW, and gradually increases to the peak around 2:00 p.m. with an average demand of 12 kW before tapering off for the rest of the day.

Chart SCE – 9b: Commercial Separate Meter (TOU-EV-8) - Average Hourly Load Profile by Day Type



Unlike the other two commercial PEV tariffs, TOU-EV-9, as shown in Chart SCE – 9c, depicts a similar load shape for both weekdays and weekends, but with a lower weekday usage during mid-day. The weekday peak averages 247 kW around 1:00 p.m., 20 percent lower than the weekend peak of 310 kW at 2:00 p.m. Among commercial PEV tariffs, the TOU-EV-9 charging behavior is distinct in that it peaks prominently on the weekend.

Chart SCE – 9c: Commercial Separate Meter (TOU-EV-9) - Average Hourly Load Profile by Day Type



Average Non-Coincident Peak Load

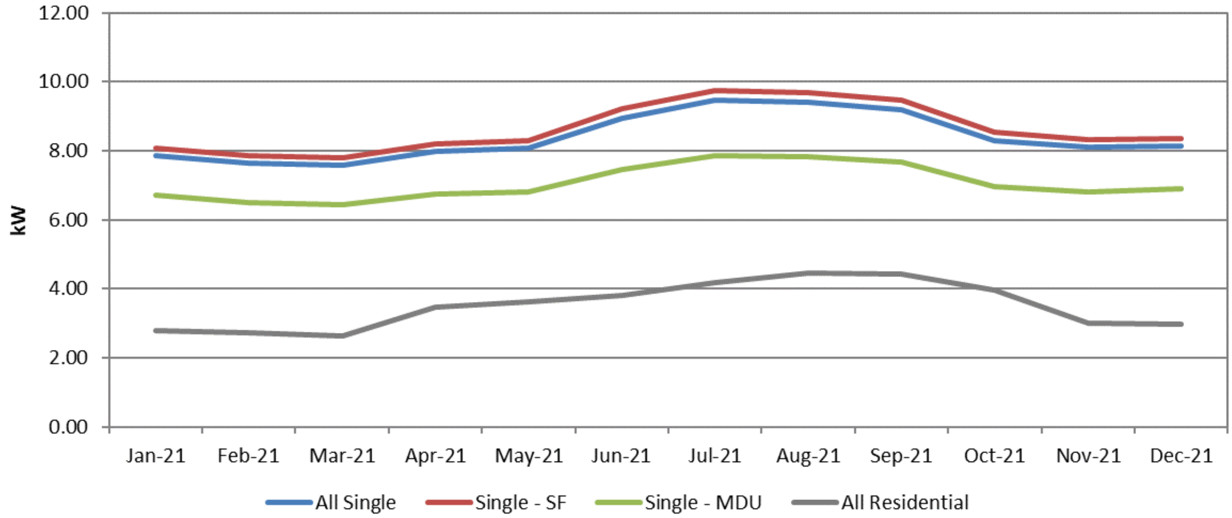
The size and timing of demands on the distribution system as a result of PEV charging is necessary to understand any potential impacts on reliability. This first section will look at the non-coincident peaks for the indvidual accounts with EVs. Subsequently the diversified group peak will be considered.

The average monthly non-coincident peak for all single-metered PEV households of 8.4 kW, as shown in Table SCE – 9, is on average 4.9 kW higher than the residential population as a whole. Chart SCE – 10 shows a seasonal fluctuation in non-coincident demands ranging from a high of 9.5 kW in July 2021 to a low of 7.6 kW in February 2021. The non-coincident demands for single-metered households are about twice as large as the non-coincident demands for general residential population. The general residential population, however, displays a similar seasonal variation in non-coincident demand levels.

Table SCE – 9: Single Meter (TOU-D-PRIME) – Monthly Average Non-Coincident Peak Load (kW)

Month	Residential Pop.	SF Pop.	MDU Pop.	All Single Metering	SF Single Metering	MDU Single Metering
Jan-21	2.78	3.03	2.39	7.86	8.07	6.71
Feb-21	2.72	2.97	2.35	7.64	7.85	6.49
Mar-21	2.64	2.88	2.28	7.59	7.80	6.42
Apr-21	3.48	3.98	2.72	7.97	8.19	6.74
May-21	3.62	4.23	2.72	8.06	8.29	6.80
Jun-21	3.81	4.46	2.82	8.95	9.21	7.46
Jul-21	4.17	4.94	3.03	9.46	9.74	7.85
Aug-21	4.47	5.31	3.21	9.40	9.68	7.83
Sep-21	4.43	5.26	3.19	9.19	9.46	7.66
Oct-21	3.95	4.62	2.96	8.30	8.54	6.97
Nov-21	3.01	3.35	2.52	8.09	8.31	6.80
Dec-21	2.97	3.29	2.50	8.13	8.34	6.89

Chart SCE – 10: Residential Meter (TOU-D-PRIME) – Monthly Average Non-Coincident Peak Load (kW)

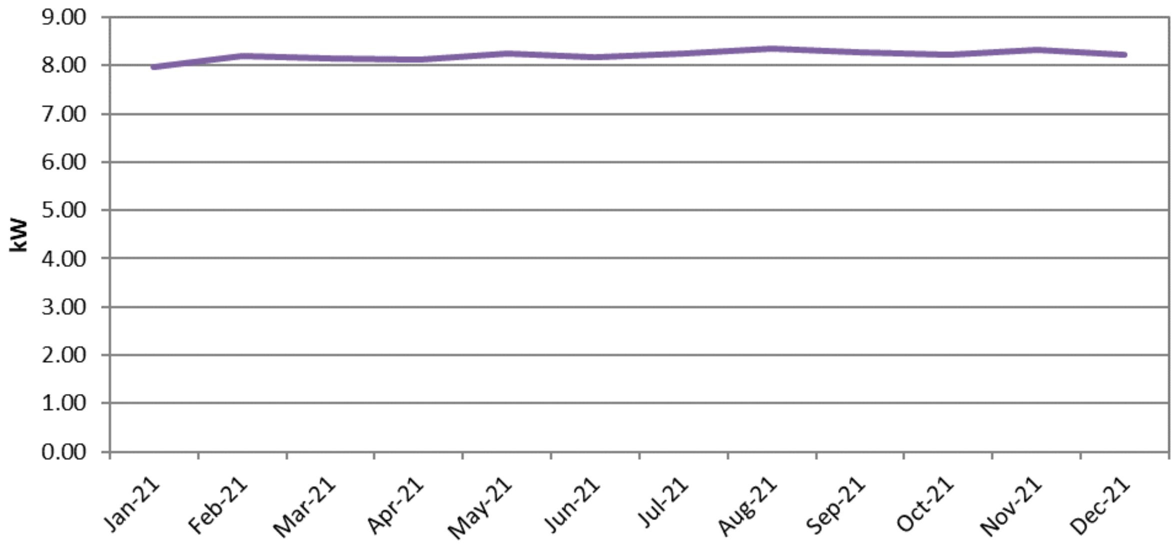


For separately-metered PEV loads, Table SCE – 10 and Chart SCE – 11 show a steady monthly non-coincident demand. The non-coincident demand averaged 8.2 kW for the whole period.

Table SCE – 10: Residential Separate Meter (TOU-EV-1) – Monthly Average Non-Coincident Peak Load (kW)

Month	Separate Metering
Jan-21	7.96
Feb-21	8.20
Mar-21	8.14
Apr-21	8.12
May-21	8.24
Jun-21	8.16
Jul-21	8.25
Aug-21	8.35
Sep-21	8.27
Oct-21	8.23
Nov-21	8.33
Dec-21	8.21

Chart SCE – 11: Separate Meter (TOU-EV-1) – Monthly Average Non-Coincident Peak Load (kW)



The average monthly non-coincident peak for TOU-EV-7, TOU-EV-8 and TOU-EV-9, shown in Chart SCE – 12a, 12b and 12c respectively, correspond to their average monthly usage pattern that continuouly grow during the study time period. The avearage monthly non-coincident peak for TOU-EV-7 remains near 10 kW in the last two quarters of 2021. TOU-EV-8 hits the highest average monthly non-conincident peak of 82 kW in December 2021 and TOU-EV-9 hits the highest peak at 709 kW in December 2021. Both have surpassed pre-pandemic levels of early 2020.

Table SCE – 11: Commercial Separate Meters – Monthly Average Non-Coincident Peak Load (kW)

Month	TOU-EV-7	TOU-EV-8	TOU-EV-9
Jan-21	7.09	54.06	487.47
Feb-21	8.23	55.36	503.21
Mar-21	8.88	56.96	531.43
Apr-21	8.67	59.99	558.87
May-21	9.82	63.32	579.02
Jun-21	9.14	66.17	570.06
Jul-21	9.50	68.29	594.59
Aug-21	10.21	72.40	605.73
Sep-21	10.02	76.14	609.38
Oct-21	10.13	79.67	623.37
Nov-21	9.88	80.96	653.04
Dec-21	9.63	81.93	708.83

Chart SCE – 12a: Commercial Separate Meter (TOU-EV-7) – Monthly Average Non-Coincident Peak Load (kW)

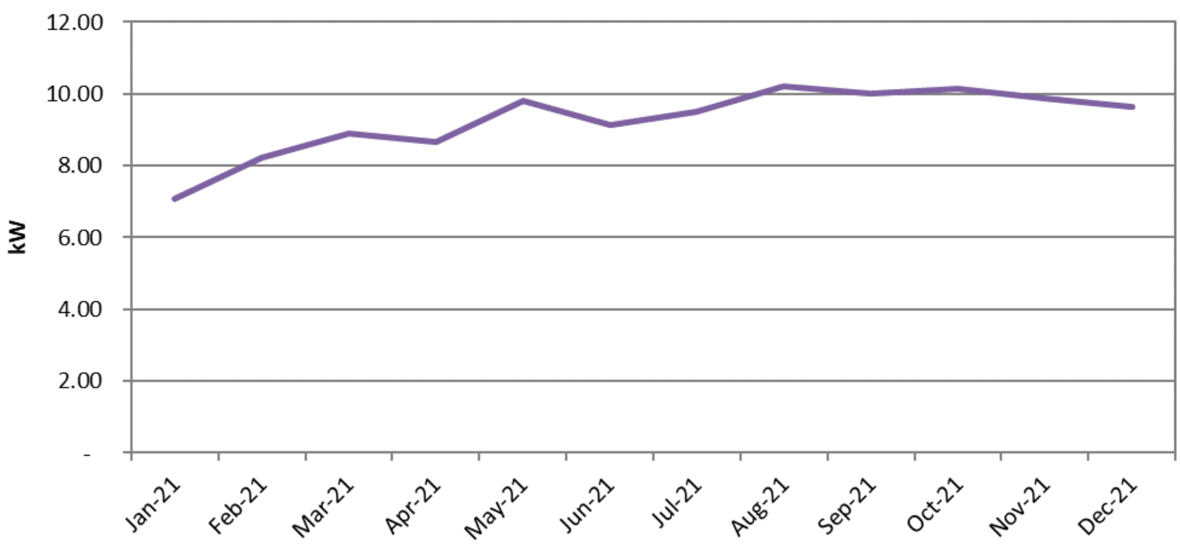


Chart SCE – 12b: Commercial Separate Meter (TOU-EV-8) – Monthly Average Non-Coincident Peak Load (kW)

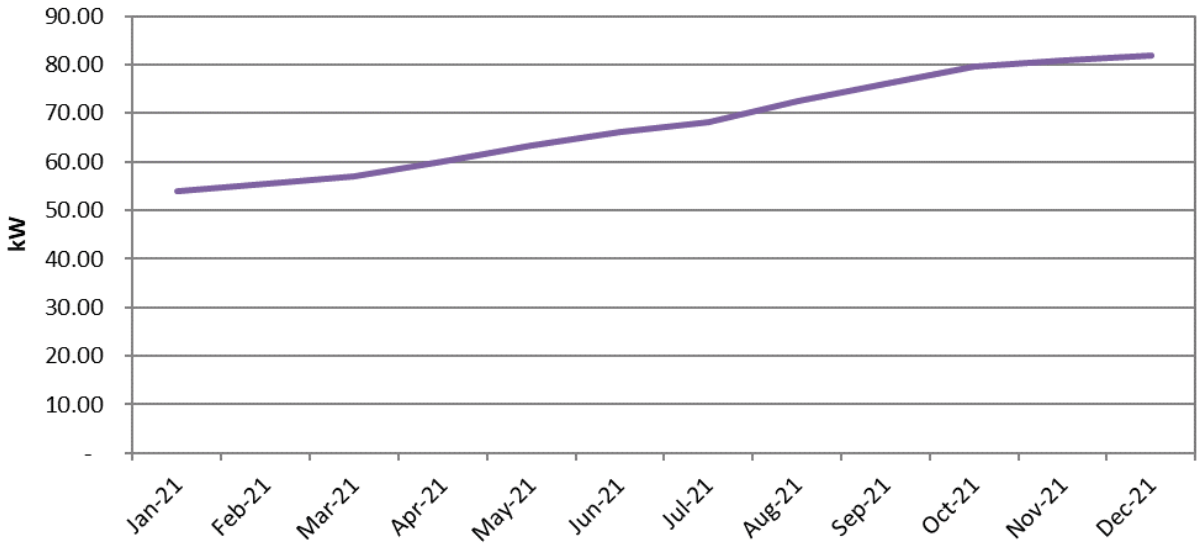
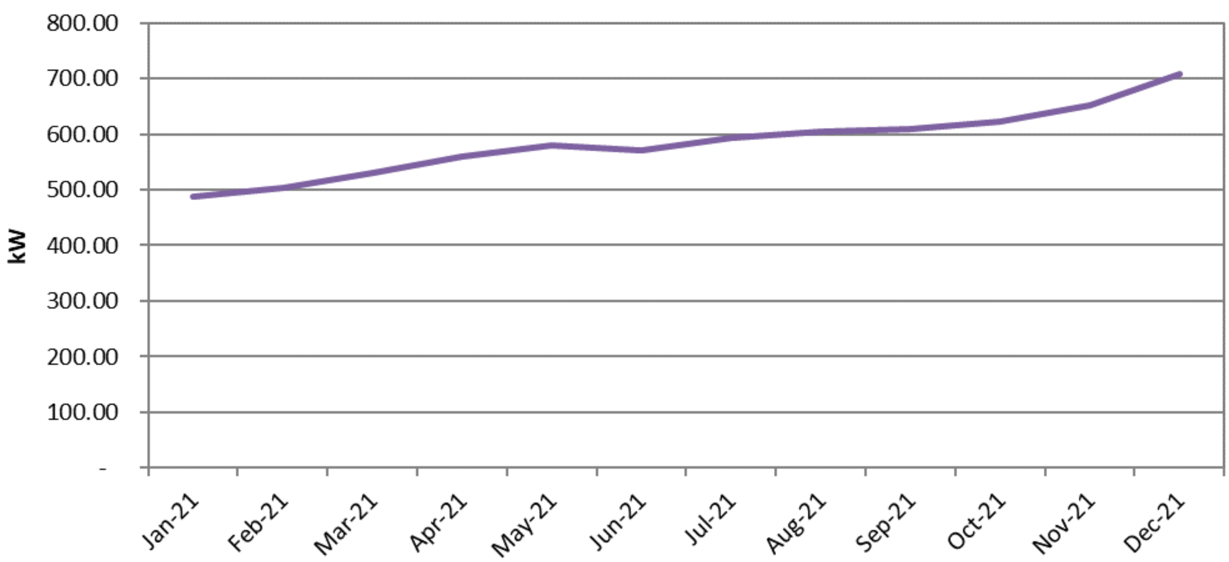


Chart SCE – 12c: Commercial Separate Meter (TOU-EV-9) – Monthly Average Non-Coincident Peak Load (kW)



Average Diversified Peak Load and Timing

In the general population, the hour of residential class peak loads varies throughout the year ranging from roughly 5:00 p.m. in the summer to 7:00 p.m. - 8:00 p.m. in the winter. The magnitude of these peaks also varies, presumably due to different uses. By comparison, the peak load for the single-metered PEV owners is much more consistent month-to-month, averaging 2.2 kW and occurring between 10 p.m. and 11 p.m. The presumed addition of PEV charging loads in the late-night hours augments household loads enough to surpass the demands occurring at other hours of the day.

Table SCE – 12a: Residential Single Meter (TOU-D-PRIME) – Time and Average Diversified Peak Load

Month	Residential Demand (kW)	Hour of Residential Demand	SF Population Demand (kW)	Hour of SF Population Demand	MDU Population Demand (kW)	Hour of MDU Population Demand
Jan. 2021	0.96	20	1.13	20	0.71	20
Feb. 2021	1.00	21	1.16	21	0.75	20
Mar. 2021	0.91	19	1.07	19	0.68	19
Apr. 2021	1.55	17	1.85	17	1.10	17
May. 2021	1.67	17	2.02	17	1.16	17
Jun. 2021	1.87	17	2.28	17	1.26	17
Jul. 2021	2.27	17	2.83	17	1.45	16
Aug. 2021	2.41	17	2.98	17	1.57	17
Sep. 2021	2.74	16	3.38	16	1.78	16
Oct. 2021	2.12	17	2.62	17	1.41	16
Nov. 2021	1.00	19	1.19	19	0.71	19
Dec. 2021	1.16	19	1.37	19	0.86	19

Table SCE – 12b cont'd: Residential Single Meter (TOU-D-PRIME) – Time and Average Diversified Peak Load

Month	Single Metering Demand (kW)	Hour of Single Metering Demand	SF Single Metering Demand (kW)	Hour of SF Single Metering Demand	MDU Single Metering Demand (kW)	Hour of MDU Single Metering Demand
Jan. 2021	1.93	23	1.99	23	1.58	23
Feb. 2021	1.95	23	2.02	23	1.59	23
Mar. 2021	1.94	23	2.01	23	1.58	23
Apr. 2021	2.01	22	2.08	22	1.62	22
May. 2021	2.09	22	2.16	22	1.71	22
Jun. 2021	2.44	22	2.52	22	1.95	22
Jul. 2021	2.75	22	2.85	22	2.18	22
Aug. 2021	2.77	22	2.87	22	2.19	22
Sep. 2021	2.55	22	2.64	22	2.01	22
Oct. 2021	2.14	22	2.21	22	1.75	22
Nov. 2021	2.03	23	2.09	23	1.65	23
Dec. 2021	2.18	23	2.25	23	1.79	23

Average monthly diversified peak loads for separately-metered PEVs is 1.2 kW with the peaks occuring between 10:00 p.m. and 11:00 p.m. This indicates a significant amount of diversity in charging as the non-coincident peak loads were 8.4 kW on average. The profiles in Chart SCE – 7 show a rather narrow peak in charging so the most plausible reason that this diversity would arise would be through vehicles not being charged daily at home.

Table SCE – 13: Residential Separate Meter (TOU-EV-1) – Time and Average Diversified Peak Load

Month	Separate Metering Demand (kW)	Hour of Separate Metering Demand
Jan. 2021	1.02	23
Feb. 2021	1.12	23
Mar. 2021	1.16	23
Apr. 2021	1.19	22
May. 2021	1.30	22
Jun. 2021	1.29	22
Jul. 2021	1.29	22
Aug. 2021	1.29	22
Sep. 2021	1.32	22
Oct. 2021	1.34	22
Nov. 2021	1.29	23
Dec. 2021	1.24	23

The average diversified peak loads for commercial TOU-EV-7 in Table SCE – 14, continued recovering from the impacts resulting from the COVID-19 outbreak and peaked around 1.8 kW during August and September. The seasonal peak follows the California full reopening announced in June 2021. A few accounts with high demand migrated out of TOU-EV-7 and into TOU-EV-8 after summer, therefore, the average diversified peak experienced a slight decline in the last quarter of 2021. The hour of peak loads varies occur the most between 9:00 a.m. to 10:00 a.m.

Table SCE – 14 also provides average diversified peak loads for commercial TOU-EV-8 and TOU-EV-9. The pattern of average diversified peak loads is nearly identical with its pattern of non-coincident peak loads that kept climbing up throughout 2021. For TOU-EV-8, the highest diversified peak load averaged 16 kW in December 2021. The hour of peak loads varies from noon to 6:00 p.m. with a tendency to occur in early afternoon during the second half of 2021. For TOU-EV-9, the highest diversified peak load averaged 349 kW in December 2021. The load for TOU-EV-9 occurs in a narrower window from noon to 4:00 p.m.

Table SCE – 14: Commercial Separate Meter – Time and Average Diversified Peak Load

Month	TOU-EV-7 Demand (kW)	TOU-EV-7 Hour of Demand	TOU-EV-8 Demand (kW)	TOU-EV-8 Hour of Demand	TOU-EV-9 Demand (kW)	TOU-EV-9 Hour of Demand
Jan. 2021	0.90	11	8.51	18	205.48	16
Feb. 2021	1.17	15	8.96	16	219.15	13
Mar. 2021	1.39	10	8.99	16	240.53	13
Apr. 2021	1.44	13	10.06	14	256.51	13
May. 2021	1.44	10	10.85	15	272.62	13
Jun. 2021	1.54	9	12.18	15	278.52	13
Jul. 2021	1.67	10	12.90	15	291.60	13
Aug. 2021	1.79	10	13.71	14	290.04	13
Sep. 2021	1.81	9	14.26	12	287.51	13
Oct. 2021	1.72	9	15.07	14	298.27	12
Nov. 2021	1.60	10	16.05	13	312.40	14
Dec. 2021	1.47	11	16.20	14	349.44	15

SCE Conclusions and Observations

The statistics and metrics found in this report are based on a sub-population of the total numbers of vehicles sold. As fuel and materials costs fluctuate, vehicle options expand, and technology continues to adapt to customer needs, the future population of owners may have different characteristics and behaviors than the current group. To-date each subsequent report has contained more PEVs but the electric use patterns have remained very consistent.

Residential

- Identification of single-metered TOU and regular domestic accounts of PEV owners relies on self-identification and therefore is subject to selection bias. Furthermore, present ownership of a PEV is not verifiable, thus the extent to which PEV charging load is a component of the metered household load cannot be determined. The reliability of this information therefore cannot be guaranteed.
- SCE was able to utilize participation data from its Clean Fuel Rebate program and the California Clean Fuel Reward program, funded by Low Carbon Fuel Standard credit revenues, to identify a significant number of additional PEV customers.
- A total of 32,380 accounts with a PEV charging under the single-meter TOU-D-PRIME tariff have been identified as of the beginning of December 2021. However, as this rate is open to all residential customers, SCE must rely on self-identification and Clean Fuel Reward Program. Therefore, account growth may not represent the actual numbers of PEVs on the single-metered TOU option or the broader PEV market growth.
- Non-coincident peak demand for the residential separately-metered PEVs was 8.2 kW on average during 2021. For comparison, average non-coincident demand was 8.5 kW in the 2019-2020 report, and 8.4 kW in the 2018 report.
- Charging continues to appear concentrated in the off-peak TOU period for single-metered PEV customers. For the separately-metered PEVs, off-peak charging remained just under 90 percent in the previous reports, however since 2020, off-peak charging has shown a decline to around 80 percent.
- There are no appreciable seasonal charging patterns from the identified PEVs, however charging appears to be lower on weekends.

Commercial

- There has been considerable customer growth in commercial PEV tariff adoption, driven in part by utility PEV charging infrastructure programs. As of the beginning of December 2021, a total of 564 accounts with PEV charging were under the three commercial PEV tariffs, compared to 476 accounts in December 2020.

- Average monthly usage has increased steadily in 2021. The trend is more persistent with TOU-EV-8 and TOU-EV-9 than with TOU-EV-7. Since June 2021, when California has moved beyond the Blueprint for a Safer Economy and fully reopened the economy, the average monthly usage for commercial PEV tariffs has surpassed pre-pandemic usage levels.
- Average monthly demand has been steadily growing during the twelve month period. As of June 2021, the average monthly non-coincident demand of TOU-EV-8 and TOU-EV-9 has surpassed the pre-pandemic level from February 2020; it continued increasing through December 2021.
- Diversified peak demands for TOU-EV-7 mainly occurred from 9 a.m. to 10 a.m. in the morning. For TOU-EV-8 and TOU-EV-9, diversified peak demands occurred later in the day, mainly occurring from 1 p.m. to 3 p.m.
- The greatest share of usage occurs in lowest cost window which is off-peak in summer and super off-peak in winter. However, it is not known if this is natural charging behavior or whether customers are responding to the TOU pricing because most charging stations and public facilities do not differentiate TOU prices for individual users.
- For TOU-EV-7, charging is higher on weekdays than weekends peaking in the morning. TOU-EV-8 charging is also higher on weekdays but to a lesser degree, peaking in the afternoon. Conversely, peak charging for TOU-EV-9 accounts occurs on weekends, also peaking in the afternoon.

TE Pilots-Programs

- For conclusions and observations, please refer to SCE's Charge Ready Pilot & Bridge Quarterly Reports and the Priority Review Projects (PRP) Final reports published on March 31, 2021.

Transportation Electrification Program Load Data

This report includes load data from SCE's Charge Ready Pilot and Bridge programs only. The report does not capture load information from SCE's Charge Ready Transport, AB 1082 – Schools and AB 1083 Parks and Beaches programs and Charge Ready Light-Duty as the sites participating in these programs were generally still in the assessment, design, development, and construction phases during 2021 and had less than 15 customers.

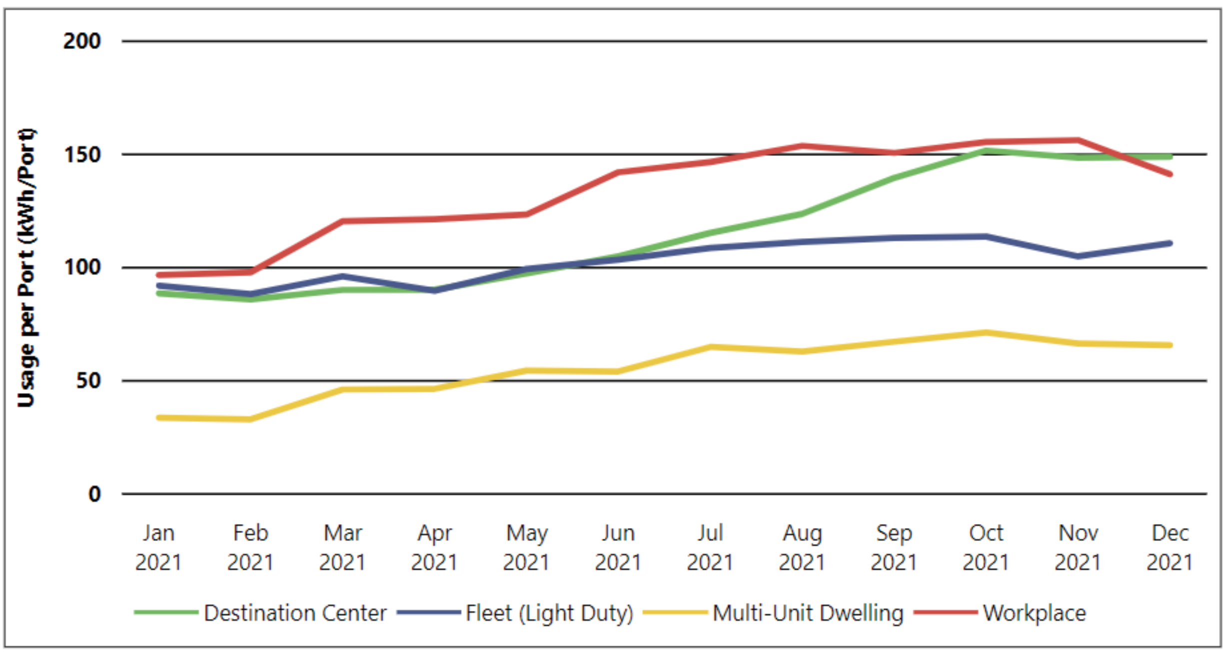
Please see submittal of SB 350 PRP Report to be filed in June 2022 for detail into 2021 load data for PRP programs.

Average Monthly Usage (kWh) per port

The graph in Chart SCE – 15 provides the average monthly usage per port for SCE's Charge Ready Pilot & Bridge program in 2021. Coming into 2021, construction was completed for 144 Charge Ready Pilot & Bridge program sites (2,720 ports). By the end of 2021, construction was completed for 2 additional sites (25 ports) taking the total of construction completed Charge Ready Bridge program sites to 146 (2,745 ports). In 2021, post COVID impacts and the slow maturing of Charge Ready Bridge projects are still noticeable as there is slow recovery from the dip that occurred in 2020. The 2021 graph shows our current usage trending toward 2019 pre-pandemic consumption in each market segment.

The average usage per port peaks in October, 151 kWh for Destination Center, 113 kWh for fleet, and 70 kWh for Multi-Unit Dwelling. Workplace's average usage per port peaks in November with 155 kWh. Workplace continues to show stronger utilization in comparison with the other segments.

Chart SCE – 15: Charge Ready Pilot & Bridge Average Monthly Usage (kWh) by Port (2021)



Average Hourly Load profile (kWh) by Port

Chart SCE -16a displays the average weekday hourly load profile by port for the Charge Ready Pilot and Bridge program by segment in 2021. The average weekday hourly load profile by port shows Workplace peak usage per port average at 9AM and Destination Centers having a peak average usage per port at 10AM, while Fleet (Light-duty) peaks at 7PM, and Multi-Unit Dwelling peaks from 9PM to 10PM.

Additionally, Chart SCE – 16b displays the average weekend hourly load profile by segment per port for 2021. Workplace charging is much lower on weekends and the shape is flatter in comparison with weekdays. The peak for Destination Center is shifted slightly more toward the early afternoon hours from 2PM to 3PM when compared to the weekday load profile. The Fleet (Light-Duty) has peaks at both 7PM which is similar to weekdays and another peak at 10PM**.** Multi-Unit Dwelling peaks at 10PM on weekends which is similar to weekday load.

SCE 16a and 16b provide average weekday and weekend hourly load profile by port in 2021. The usages reflected in both charts indicate a slow recovery from COVID-19 impacts and subsequently, slow increase in usage of the stations associated with Charge Ready Bridge projects from 2020. Overall, these two 2021 charts demonstrate very similar average usage per port load shapes in comparison with 2020 load profiles. However, Destination Center Weekday/Weekend load shape shows average usage closer to pre-COVID-19 periods.

Chart SCE – 16a: Charge Ready Pilot & Bridge Average Weekday Hourly Load Profile (kWh) by Port (2021)

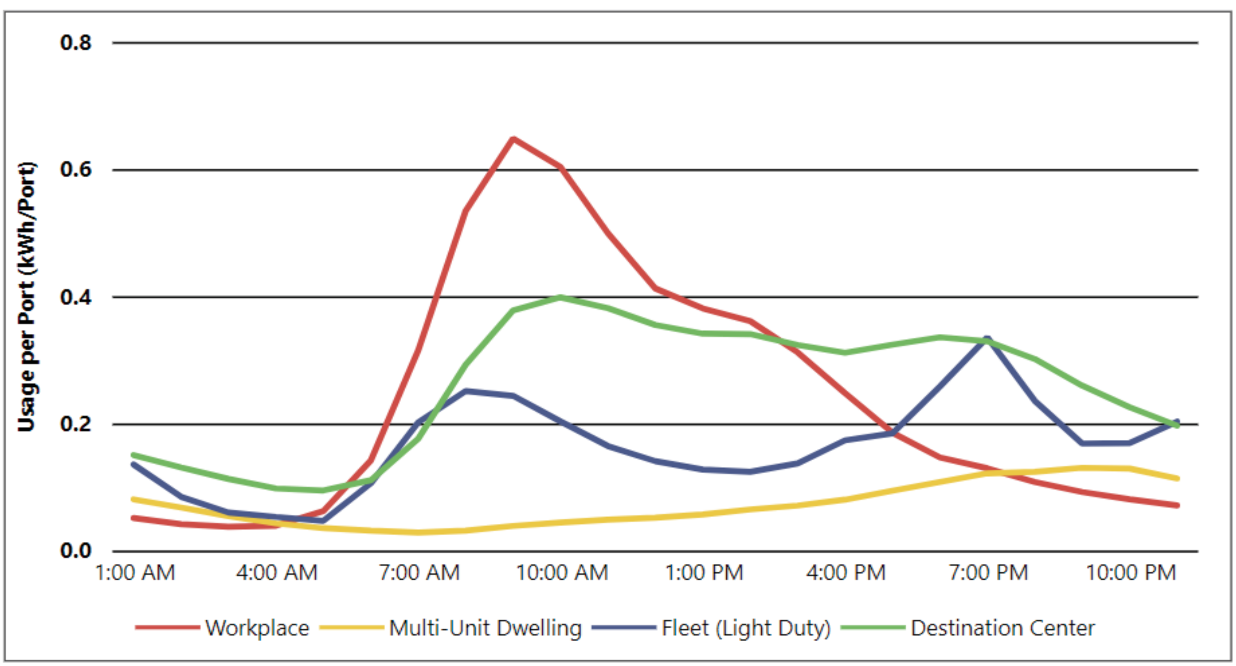
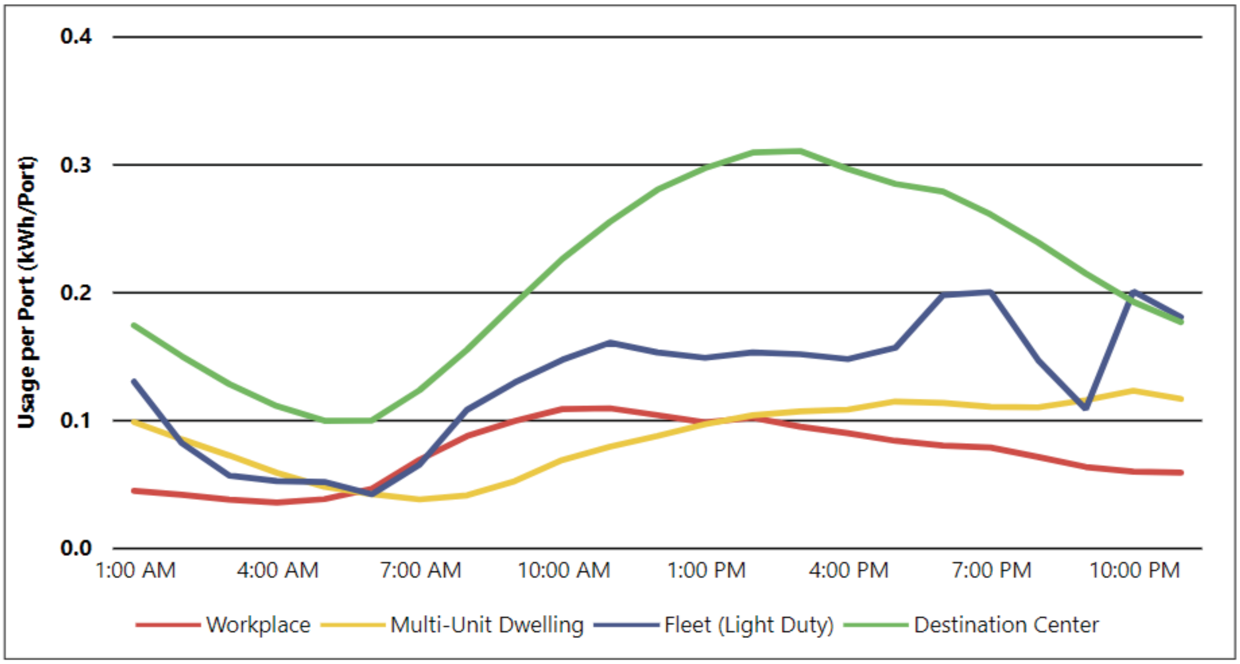


Chart SCE – 16b: Charge Ready Pilot & Bridge Average Weekend Hourly Load Profile (kWh) by Port (2021)



D. SDG&E's Residential EV Load and Customer Behavior Data

Load consumption across SDG&E's electric vehicle (EV)-specific rates and Transportation Electrification Programs are reported in the following sections. The study period covers Residential EV rates only for the full 2021 calendar year. The residential rates include SDG&E's separately metered rate (EV-TOU) and single metered rates (EV-TOU-2, EV-TOU-2 (GF), and EV-TOU-5).

SDG&E Single-Metered PEV Residential Rates

SDG&E has two residential plug-in electric vehicle (PEV) rates open to single-metered customers (EV-TOU-2 and EV-TOU-5). In addition, SDG&E has a grandfathered EV rate (EV-TOU-2 (GF)) for Net Energy Metering (NEM) customers before June 2017 with legacy time of use (TOU) periods and is only available to NEM customers for five years.

EV TOU-2:
The EV-TOU-2 rate option is designed for residential customers that have both their household load and PEV load on the same meter. Service under this optional rate is specifically limited to residential customers who require service for charging a currently registered motor vehicle which is: (1) a battery electric vehicle (BEV) or plug-in hybrid vehicle (PHEV) recharged via a recharging outlet at the customer's premise; or (2) a natural gas vehicle (NGV) refueled via a home refueling appliance (HRA) at the customer's premise.

EV-TOU-2 (GF):
The EV-TOU-2 (GF) rate, which is the grandfathered version of the EV-TOU-2 rate, has the same design criteria as the EV-TOU-2 rate, but with different TOU periods and pricing. This rate is for NEM customers who opted into a TOU tariff prior to July 31, 2017. After the customer's fifth anniversary of the installation of their solar photovoltaic (PV) system, the customer is no longer eligible for this rate and must switch to another applicable rate.

EV-TOU-5:
The EV-TOU-5 rate has the same design criteria as the EV-TOU-2 rate. It has the same TOU periods as the EV-TOU-2 rate, but with different pricing. The main difference is that customers under this rate pay a $16 monthly fixed charge, and subsequently have a much lower super off-peak energy price.

The single-metered rates are designed for residential customers who have their typical load and electric vehicle charging on the same meter. All EV rate plans use an un-tiered TOU rate structure. They offer on-peak, off-peak, and super off-peak energy prices according to the time periods and pricing shown in Table SDG&E-1A. Regardless of season or day of the week, both rates seek to encourage usage in off-peak and super off-peak hours.

SDG&E Separate-Metered PEV Rate

EV-TOU:
The EV-TOU rate option is designed for residential customers that have their PEV load on a dedicated meter and electric service. This is an optional rate for residential customers who require service for charging of a currently registered motor vehicle which is one of the following: (1) a BEV or PHEV recharged via a recharging outlet at the customer's premise; or (2) an NGV refueled via an HRA at the

customer's premise. The point of service must contain facilities to separately meter PEV or Compressed Natural Gas (CNG) charging.

Table SDG&E-1A: Tariff Type and Rate ($/kWh) in 2021

EV-TOU				
HOUR	WINTER WEEKDAY	WINTER WEEKEND / HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND / HOLIDAY
12AM - 1AM	0.23465	0.23465	0.24106	0.24106
1AM - 2AM	0.23465	0.23465	0.24106	0.24106
2AM - 3AM	0.23465	0.23465	0.24106	0.24106
3AM - 4AM	0.23465	0.23465	0.24106	0.24106
4AM - 5AM	0.23465	0.23465	0.24106	0.24106
5AM - 6AM	0.23465	0.23465	0.24106	0.24106
6AM - 7AM	0.39627	0.23465	0.42215	0.24106
7AM - 8AM	0.39627	0.23465	0.42215	0.24106
8AM - 9AM	0.39627	0.23465	0.42215	0.24106
9AM - 10AM	0.39627	0.23465	0.42215	0.24106
10AM - 11AM	0.39627	0.23465	0.42215	0.24106
11AM - 12PM	0.39627	0.23465	0.42215	0.24106
12PM - 1PM	0.39627	0.23465	0.42215	0.24106
1PM - 2PM	0.39627	0.23465	0.42215	0.24106
2PM - 3PM	0.39627	0.39627	0.42215	0.42215
3PM - 4PM	0.39627	0.39627	0.42215	0.42215
4PM - 5PM	0.44545	0.44545	0.68065	0.68065
5PM - 6PM	0.44545	0.44545	0.68065	0.68065
6PM - 7PM	0.44545	0.44545	0.68065	0.68065
7PM - 8PM	0.44545	0.44545	0.68065	0.68065
8PM - 9PM	0.44545	0.44545	0.68065	0.68065
9PM - 10PM	0.39627	0.39627	0.42215	0.42215
10PM - 11PM	0.39627	0.39627	0.42215	0.42215
11PM - 12AM	0.39627	0.39627	0.42215	0.42215

EV-TOU-2				
HOUR	WINTER WEEKDAY	WINTER WEEKEND / HOLIDAY	SUMMER WEEKDAY	SUMMER WEEKEND / HOLIDAY
12AM - 1AM	0.23465	0.23465	0.24106	0.24106
1AM - 2AM	0.23465	0.23465	0.24106	0.24106

2AM - 3AM	0.23465	0.23465	0.24106	0.24106
3AM - 4AM	0.23465	0.23465	0.24106	0.24106
4AM - 5AM	0.23465	0.23465	0.24106	0.24106
5AM - 6AM	0.23465	0.23465	0.24106	0.24106
6AM - 7AM	0.39627	0.23465	0.42215	0.24106
7AM - 8AM	0.39627	0.23465	0.42215	0.24106
8AM - 9AM	0.39627	0.23465	0.42215	0.24106
9AM - 10AM	0.39627	0.23465	0.42215	0.24106
10AM - 11AM	0.39627	0.23465	0.42215	0.24106
11AM - 12PM	0.39627	0.23465	0.42215	0.24106
12PM - 1PM	0.39627	0.23465	0.42215	0.24106
1PM - 2PM	0.39627	0.23465	0.42215	0.24106
2PM - 3PM	0.39627	0.39627	0.42215	0.42215
3PM - 4PM	0.39627	0.39627	0.42215	0.42215
4PM - 5PM	0.44545	0.44545	0.68065	0.68065
5PM - 6PM	0.44545	0.44545	0.68065	0.68065
6PM - 7PM	0.44545	0.44545	0.68065	0.68065
7PM - 8PM	0.44545	0.44545	0.68065	0.68065
8PM - 9PM	0.44545	0.44545	0.68065	0.68065
9PM - 10PM	0.39627	0.39627	0.42215	0.42215
10PM - 11PM	0.39627	0.39627	0.42215	0.42215
11PM - 12AM	0.39627	0.39627	0.42215	0.42215

EV-TOU-2 (GF)				
HOUR	**WINTER WEEKDAY**	**WINTER WEEKEND / HOLIDAY**	**SUMMER WEEKDAY**	**SUMMER WEEKEND / HOLIDAY**
12AM - 1AM	0.44759	0.44759	0.46045	0.46045
1AM - 2AM	0.44759	0.44759	0.46045	0.46045
2AM - 3AM	0.44759	0.44759	0.46045	0.46045
3AM - 4AM	0.44759	0.44759	0.46045	0.46045
4AM - 5AM	0.44759	0.44759	0.46045	0.46045
5AM - 6AM	0.36863	0.36863	0.38149	0.38149
6AM - 7AM	0.36863	0.36863	0.38149	0.38149
7AM - 8AM	0.36863	0.36863	0.38149	0.38149
8AM - 9AM	0.36863	0.36863	0.38149	0.38149
9AM - 10AM	0.36863	0.36863	0.38149	0.38149
10AM - 11AM	0.36863	0.36863	0.38149	0.38149
11AM - 12PM	0.36863	0.36863	0.38149	0.38149
12PM - 1PM	0.70646	0.70646	0.46047	0.46047

1PM - 2PM	0.70646	0.70646	0.46047	0.46047
2PM - 3PM	0.70646	0.70646	0.46047	0.46047
3PM - 4PM	0.70646	0.70646	0.46047	0.46047
4PM - 5PM	0.70646	0.70646	0.46047	0.46047
5PM - 6PM	0.70646	0.70646	0.46047	0.46047
6PM - 7PM	0.36863	0.36863	0.38149	0.38149
7PM - 8PM	0.36863	0.36863	0.38149	0.38149
8PM - 9PM	0.36863	0.36863	0.38149	0.38149
9PM - 10PM	0.36863	0.36863	0.38149	0.38149
10PM - 11PM	0.36863	0.36863	0.38149	0.38149
11PM - 12AM	0.36863	0.36863	0.38149	0.38149

EV-TOU-5 (BASIC SERVICE FEE $16)				
HOUR	**WINTER WEEKDAY**	**WINTER WEEKEND / HOLIDAY**	**SUMMER WEEKDAY**	**SUMMER WEEKEND / HOLIDAY**
12AM - 1AM	0.10201	0.10201	0.10842	0.10842
1AM - 2AM	0.10201	0.10201	0.10842	0.10842
2AM - 3AM	0.10201	0.10201	0.10842	0.10842
3AM - 4AM	0.10201	0.10201	0.10842	0.10842
4AM - 5AM	0.10201	0.10201	0.10842	0.10842
5AM - 6AM	0.10201	0.10201	0.10842	0.10842
6AM - 7AM	0.36864	0.10201	0.39452	0.10842
7AM - 8AM	0.36864	0.10201	0.39452	0.10842
8AM - 9AM	0.36864	0.10201	0.39452	0.10842
9AM - 10AM	0.36864	0.10201	0.39452	0.10842
10AM - 11AM	0.36864	0.10201	0.39452	0.10842
11AM - 12PM	0.36864	0.10201	0.39452	0.10842
12PM - 1PM	0.36864	0.10201	0.39452	0.10842
1PM - 2PM	0.36864	0.10201	0.39452	0.10842
2PM - 3PM	0.36864	0.36864	0.39452	0.39452
3PM - 4PM	0.36864	0.36864	0.39452	0.39452
4PM - 5PM	0.41782	0.41782	0.65302	0.65302
5PM - 6PM	0.41782	0.41782	0.65302	0.65302
6PM - 7PM	0.41782	0.41782	0.65302	0.65302
7PM - 8PM	0.41782	0.41782	0.65302	0.65302
8PM - 9PM	0.41782	0.41782	0.65302	0.65302
9PM - 10PM	0.36864	0.36864	0.39452	0.39452
10PM - 11PM	0.36864	0.36864	0.39452	0.39452
11PM - 12AM	0.36864	0.36864	0.39452	0.39452

Legend		
	Winter	Summer
On-Peak		
Off-Peak		
Super-Off-Peak		

Table SDG&E-1B: Price Ratios for EV Rates (2021)

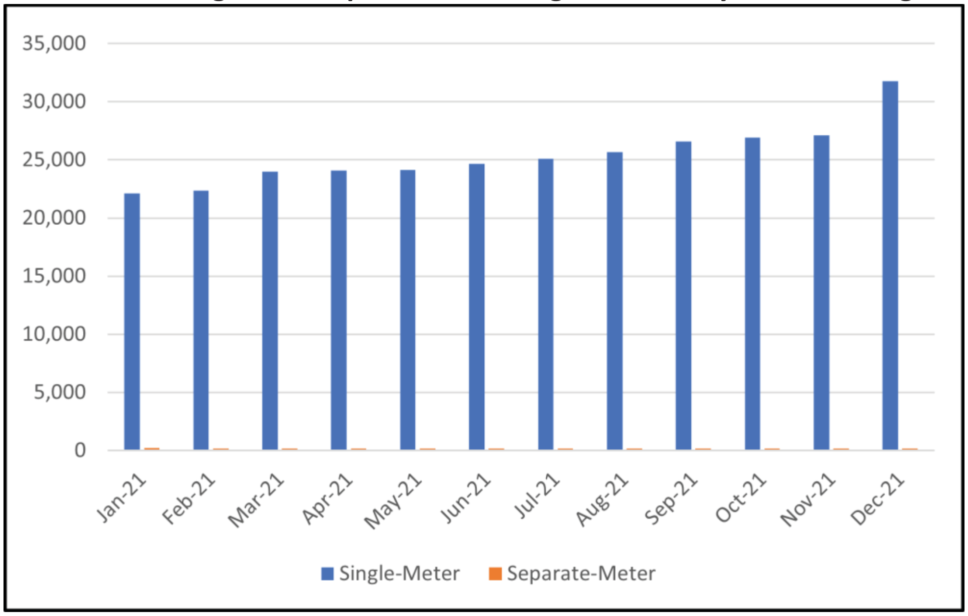
Tariff	Winter		Summer	
	Off-Peak to Super-Off-Peak	On-Peak to Super-Off-Peak	Off-Peak to Super-Off-Peak	On-Peak to Super-Off-Peak
EV-TOU	1.69	1.90	1.75	2.82
EV-TOU2	1.69	1.90	1.75	2.82
EV-TOU2 (GF)	1.21	1.92	1.21	1.21
EV-TOU5	3.61	4.10	3.64	6.02

Single-Metered Rate Growth

Participation in single-metered PEV rates showed a steady increase during 2021 while participation in the separately-metered PEV rate decreased slightly during 2021. It is important to note that not all PEV customers have adopted PEV rates. Of the customers on PEV rates, the majority are on one of the single-metered rates.

Single-Metered Customers: Chart SDG&E-1 below displays the total customers on single-metered PEV rates. During the study period, there was a steady increase in single-metered rate enrollment overall.

Chart SDG&E-1: Single and Separate Metering Accounts by Meter Configuration



Referencing Table SDG&E-3 and Chart SDG&E-1, the number of SDG&E customers taking service under separately metered EV rates has slowly decreased over the past years. This is most likely due to a small number of customers switching to a single-metered configuration to better accommodate NEM or to get a better whole-house EV rate choice (namely EV-TOU-5). Most of the customers who have left the single meter configuration participated in SDG&E's Plugin Electric Vehicle TOU Pricing and Technology Study pilot program from 2011-2013.

NEM Single-Metered Customers: NEM customers on the PEV rates are an important group to consider. Of all the SDG&E customers who were on the single-metered PEV rates during 2021, 44% were also NEM customers.

The fact that NEM customers with PEVs predominately use the single-metered rate presents a load research challenge when trying to ascertain how much energy is used by the house versus the EV(s) due to a lack of metering data, since EV charging energy and residential solar energy are usually not separately metered by the utility for these customers. In addition, the now-popular installation of onsite distributed generation (DG) in the form of battery storage tends to exacerbate the data / load research issue because of that lack of metering as well. Without additional metering of the DG and/or solar PV systems, it is not possible to isolate the effect PEV ownership has on usage patterns for this group using the utility metering data alone.

Energy consumption patterns of customers on EV rates are often different from the general residential population, for example, NEM customers with PV systems. Currently, solar PV owners are overrepresented in the PEV-rate class as compared to non-PEV customers. NEM penetration for the residential population in SDG&E's service territory is about 16%, while NEM customers currently represent approximately 44% of the single-meter PEV-rate class (as seen in Table SDG&E-2A).

Table SDG&E-2A: Total Single-Metered NEM Program Enrollment

Month	Total Customers on Single- Metering	Total Customers on NEM	NEM as a % of Single-Metering
Jan-21	22,108	10,161	46.0%
Feb-21	22,336	10,295	46.1%
Mar-21	24,001	10,457	43.6%
Apr-21	24,082	10,560	43.9%
May-21	24,145	10,743	44.5%
Jun-21	24,669	10,910	44.2%
Jul-21	25,110	11,188	44.6%
Aug-21	25,645	11,425	44.6%
Sep-21	26,590	11,444	43.0%
Oct-21	26,899	11,617	43.2%
Nov-21	27,110	11,763	43.4%
Dec-21	36,759	16,316	44.4%

Table SDG&E-2B: Single-Metered NEM Program Enrollment for EV-TOU-2

Month	Total Customers on EVTOU2	Total Customers on NEM	NEM as a % of EVTOU2
Jan-21	8,122	4,257	52.4%
Feb-21	8,079	4,296	53.2%
Mar-21	8,647	4,372	50.6%
Apr-21	8,212	3,819	46.5%
May-21	8,062	3,799	47.1%
Jun-21	8,021	3,810	47.5%
Jul-21	7,904	3,787	47.9%
Aug-21	7,834	3,795	48.4%
Sep-21	7,970	3,795	47.6%
Oct-21	7,788	3,814	49.0%
Nov-21	7,590	3,798	50.0%
Dec-21	9,095	3,803	41.8%

Table SDG&E-2C: Single-Metered NEM Program Enrollment for GEV-TOU2

Month	Total Customers on GEVTOU2	Total Customers on NEM	NEM as a % of GEVTOU2
Jan-21	1,209	1,209	100.0%
Feb-21	1,115	1,115	100.0%
Mar-21	1,037	1,037	100.0%
Apr-21	976	976	100.0%
May-21	908	908	100.0%

Jun-21	905	905	100.0%
Jul-21	898	898	100.0%
Aug-21	880	880	100.0%
Sep-21	880	880	100.0%
Oct-21	876	876	100.0%
Nov-21	871	871	100.0%
Dec-21	846	846	100.0%

Table SDG&E-2D: Single-Metered NEM Program Enrollment for EV-TOU5

Month	Total Customers on EVTOU5	Total Customers on NEM	NEM as a % of EVTOU5
Jan-21	12,820	5,051	39.4%
Feb-21	13,159	5,202	39.5%
Mar-21	14,943	6,100	40.8%
Apr-21	15,136	6,180	40.8%
May-21	15,272	6,396	41.9%
Jun-21	15,804	6,733	42.6%
Jul-21	16,254	6,949	42.8%
Aug-21	16,815	7,038	41.9%
Sep-21	17,766	7,105	40.0%
Oct-21	18,093	7,296	40.3%
Nov-21	18,312	7,465	40.8%
Dec-21	24,045	9,572	39.8%

Separately-Metered Rate Growth

All Separately-Metered Customers: The separately-metered PEV rate remains a less popular option for PEV rate customers than the single-metered PEV rate, due to the expense of installing a new electric service and a separate meter.

Table SDG&E-3: Separately-Metered Accounts Totals

Month	Total Customers on Separate- Metering	Total Customers on NEM	NEM as a % of Separate- Metering
Jan-21	190	81	42.6%
Feb-21	186	79	42.5%
Mar-21	182	77	42.3%
Apr-21	179	77	43.0%
May-21	176	75	42.6%
Jun-21	176	75	42.6%
Jul-21	174	74	42.5%
Aug-21	173	74	42.8%

Sep-21	173	74	42.8%
Oct-21	172	74	43.0%
Nov-21	172	74	43.0%
Dec-21	172	74	43.0%

Average Monthly Usage for PEV Rate Customers

Chart SDG&E-2 displays the average monthly usage for single-metered customers with and without NEM during 2021, which is the average monthly usage including behind-the-meter generation. Monthly consumption is highest in the summer months when temperatures are high, and many residential customers are using air conditioning (A/C). Monthly consumption is much lower in spring when A/C is not used as much, and NEM customers have higher levels of NEM exports.

Chart SDG&E-3 displays the average monthly usage for separate-metered customers which is average monthly home PEV charging only.

Chart SDG&E-2: Average Monthly Net Usage for Single-Meter Customers with and without NEM

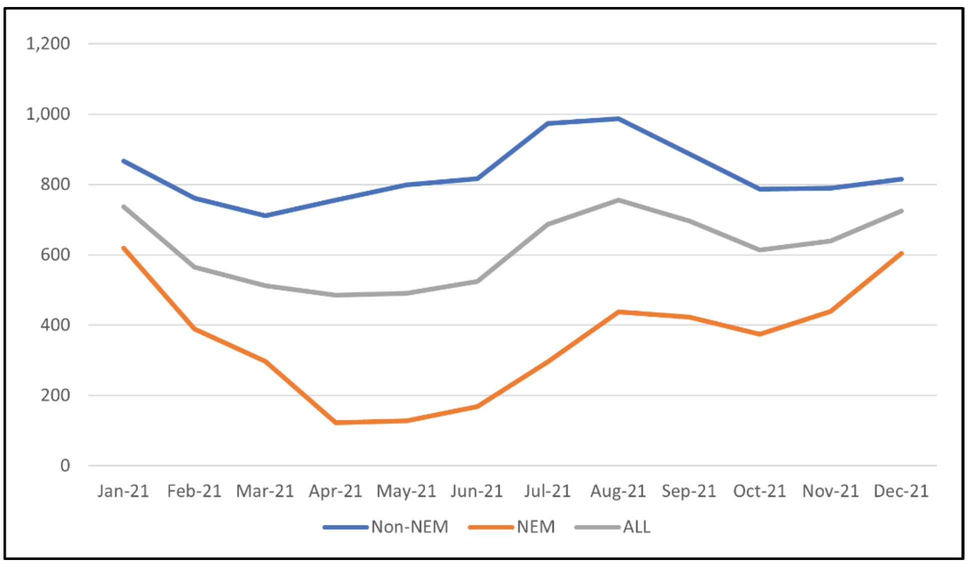
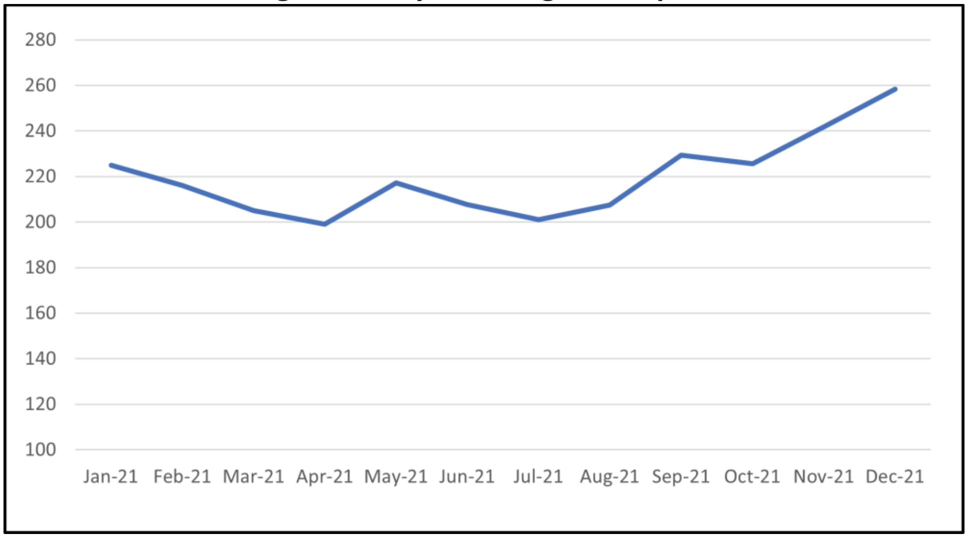


Chart SDG&E-3: Average Monthly Net Usage for Separate-Meter Customers



Time of Use Analysis of Single- and Separate-Metered Customers

One of the questions addressed in this Report is whether being on a TOU rate with higher on-peak pricing is an effective incentive to move EV charging or other household consumption to off-peak or super off-peak times. The load shapes provided in Charts SDG&E-4 and SDG&E-5 suggest that customers respond to differences in prices and charge their vehicles when electricity is the cheapest. Tables SDG&E-4a through SDG&E-4f below provide the percentage share of monthly kilowatt per hour (kWh) for single and separate-metered rates. EV-TOU-2 (GF) customers (who are also NEM customers) consume over 80% of their energy during the off-peak and super off-peak periods. EV-TOU-2 and EV-TOU-5 customers consume over 75% of their energy during the off-peak and super off-peak periods. Separate-metered customers respond very well to the signal created by the TOU price differential and consume on average almost 75% of their energy during the super off-peak TOU period.

It is important to note that the time-of-use analysis in this report reflects energy delivered to the home and does not consider exports from excess solar generation for NEM customers. SDG&E customers are billed based on their net consumption, not their delivered consumption. Monthly usage data and load shapes in this Report reflect net values to visually display this behavior. Because NEM customers export enough energy during off-peak hours to reach negative levels, time-of-use analysis is reported with delivered load to avoid displaying negative percentage values.

Table SDG&E-4A: Percentage of On-Peak Usage by Single-Meter Configuration

Season	EVTOU2 Non-NEM	EVTOU2 NEM	EVTOU2 Total	EVTOU2 (GF) Total	EVTOU5 Non-NEM	EVTOU5 NEM	EVTOU5 Total
S	24.1%	29.7%	26.6%	15.2%	20.0%	23.4%	21.3%
W	23.8%	27.4%	25.5%	13.4%	19.5%	21.6%	20.4%

Table SDG&E-4B: Percentage of On-Peak Usage by Separate-Meter Configuration

Season	EVTOU Non-NEM	EVTOU NEM	EVTOU Total
S	7.5%	9.3%	8.8%
W	8.1%	9.9%	8.6%

Table SDG&E-4C: Percentage of Off-Peak Usage by Single-Meter Configuration

Season	EVTOU2 Non-NEM	EVTOU2 NEM	EVTOU2 Total	EVTOU2 (GF) Total	EVTOU5 Non-NEM	EVTOU5 NEM	EVTOU5 Total
S	43.9%	31.8%	38.5%	48.0%	40.5%	31.1%	36.9%
W	38.6%	30.3%	34.6%	46.1%	34.1%	27.3%	31.2%

Table SDG&E-4D: Percentage of Off-Peak Usage by Separate-Meter Configuration

Season	EVTOU Non-NEM	EVTOU NEM	EVTOU Total
S	18.2%	19.0%	15.8%
W	18.4%	12.4%	15.0%

Table SDG&E-4E: Percentage of Super Off-Peak Usage by Single-Meter Configuration

Season	EVTOU2 Non-NEM	EVTOU2 NEM	EVTOU2 Total	EVTOU2 (GF) Total	EVTOU5 Non-NEM	EVTOU5 NEM	EVTOU5 Total
S	32.0%	38.6%	34.9%	36.8%	39.5%	45.6%	41.8%
W	37.6%	42.2%	39.8%	40.5%	46.4%	51.1%	48.4%

Table SDG&E-4F: Percentage of Super Off-Peak Usage by Separate-Meter Configuration

Season	EVTOU Non-NEM	EVTOU NEM	EVTOU Total
S	74.3%	71.6%	75.3%
W	73.5%	77.6%	76.3%

Average Load Profiles

Charts SDG&E-5A through SDG&E-5D compare the average load profiles for weekdays versus weekends for EV-TOU-2, EV-TOU-2 (GF), EV-TOU-5, and the combination of the three on a net basis. The net load shapes for single-metered customers show high consumption in early morning hours, low mid-day consumption due to NEM exports, and an increase in evening consumption after export hours have ended but a lower peak than the early morning. This behavior is like a typical residential net load profile except that these customers peak in the early morning (super off-peak) hours rather than in the evening (on-peak) hours. This is the effect of customers taking advantage of the super off-peak pricing to charge their vehicles. Weekends tend to have higher midday consumption because many customers are at home rather than going to work. Weekends also have lower charging levels during the early morning hours.

Chart SDG&E-4 displays similar day of week patterns for separate-metered PEV customers. These accounts peak in the 01:00 – 02:00 hour timeframe and have negligible consumption during the rest of the day. This would indicate that the rate structure and enabling technology are successful in encouraging charging mainly during the super off-peak hours.

Chart SDG&E-4: Average Net Load Profile for Separate-Meter Customers (EV-TOU) by Weekday/Weekend for 2021

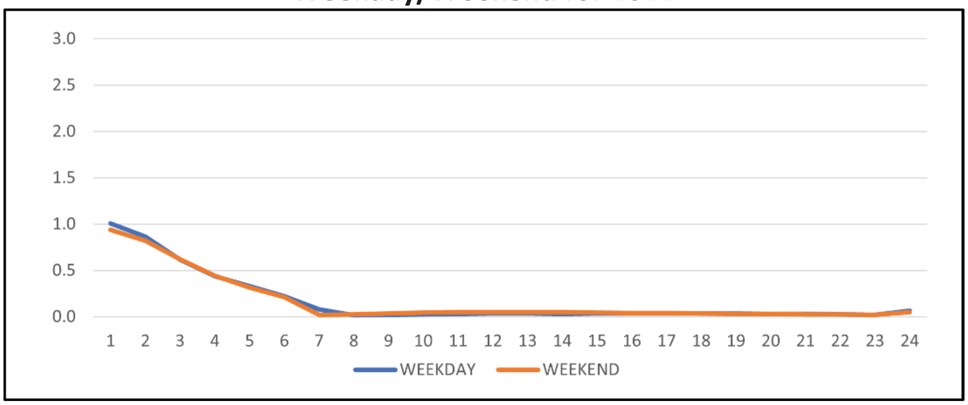


Chart SDG&E-5A: Average Net Load Profile for EV-TOU-2 by Weekday/Weekend for 2021

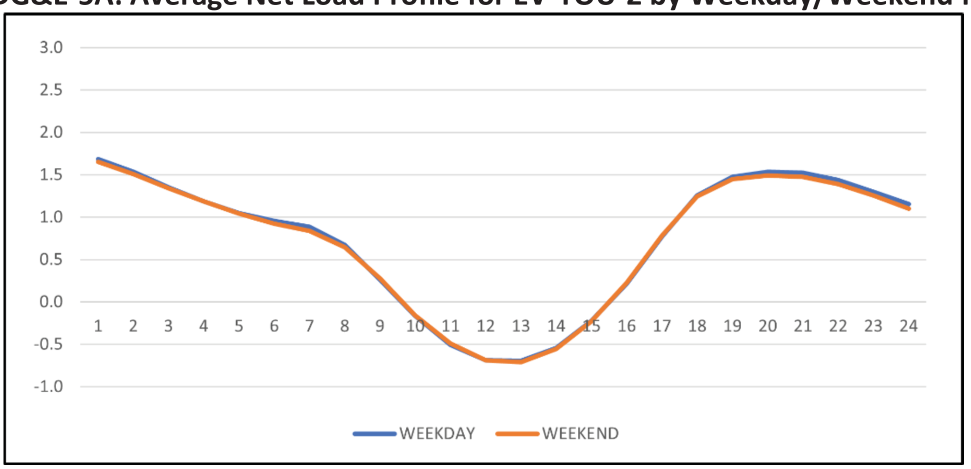


Chart SDG&E-5B: Average Net Load Profile for EV-TOU-2 (GF) by Weekday/Weekend for 2021

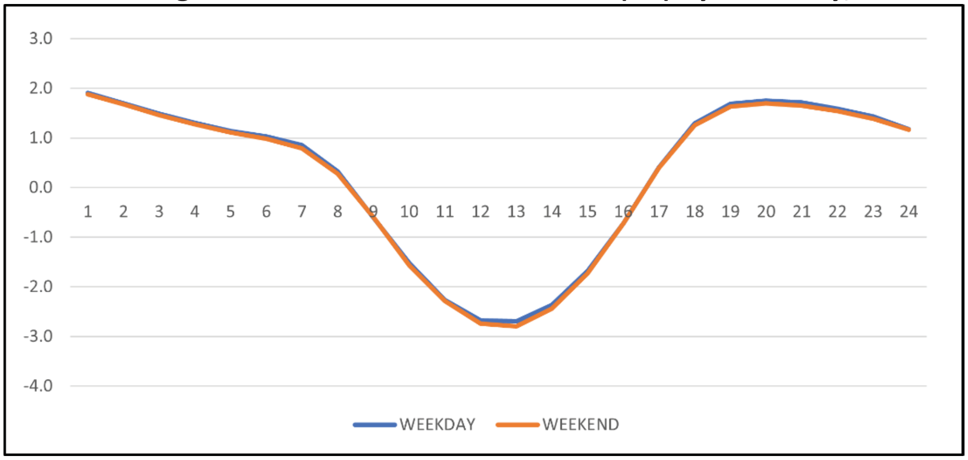


Chart SDG&E-5C: Average Net Load Profile for EV-TOU-5 by Weekday/Weekend for 2021

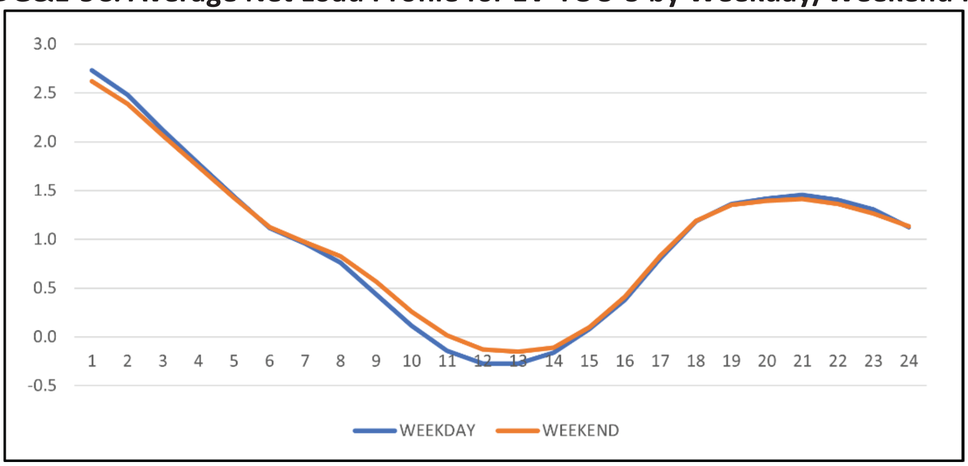
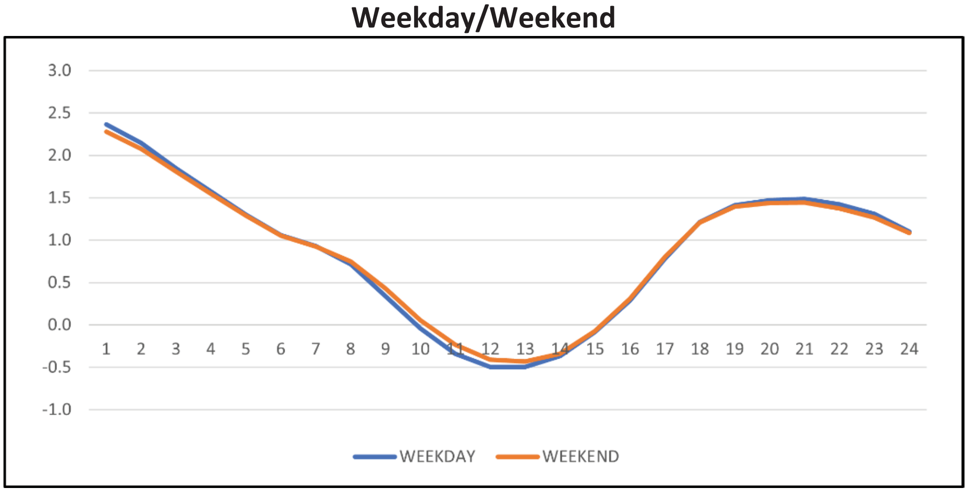


Chart SDG&E-5D: Average Net Load Profile for All Single-Meter Customers by Weekday/Weekend



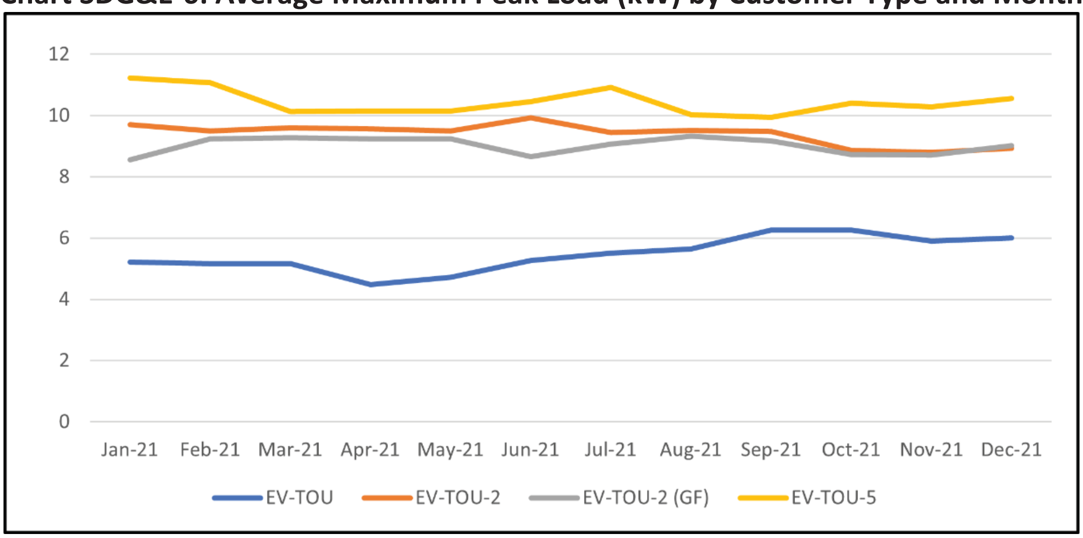
Average Maximum Peak Load (Diversified Demand)

Table SDG&E-5 shows that the average maximum peak demand (also referred to as diversified demand) for separate-meter customers is over 5 kW. Demands are based on maximum hourly kWh values. Single-meter customers have a maximum demand more than twice that of the average residential customer, which is driven by the addition of the EV charging load to the base house load.

Table SDG&E-5: Average Maximum Peak Load (kW) by Customer Type and Month

Month	EV-TOU	EV-TOU-2	EV-TOU-2 (GF)	EV-TOU-5
Jan-21	5.21	9.70	8.55	11.23
Feb-21	5.17	9.50	9.24	11.07
Mar-21	5.17	9.61	9.28	10.13
Apr-21	4.49	9.57	9.23	10.15
May-21	4.73	9.50	9.24	10.15
Jun-21	5.26	9.92	8.66	10.45
Jul-21	5.51	9.44	9.07	10.92
Aug-21	5.65	9.52	9.33	10.03
Sep-21	6.27	9.47	9.17	9.93
Oct-21	6.27	8.86	8.73	10.40
Nov-21	5.90	8.80	8.71	10.29
Dec-21	6.01	8.93	9.03	10.56

Chart SDG&E-6: Average Maximum Peak Load (kW) by Customer Type and Month



Time and Average Class Peak Load

Both single-meter and separate-meter customers peak around 12:30 AM and 01:30 AM driven by PEV charging behavior and taking advantage of lower super-off-peak prices as shown in Table SDG&E-6. Comparatively, the residential class usually peaks in the early evening hours. Demands are based on maximum hourly kWh values.

Table SDG&E-6: Time and Associated Demand of Class Peak Load

Month	EV-TOU		EV-TOU-2		EV-TOU-2 (GF)		EV-TOU-5	
	Time	kWh	Time	kWh	Time	kWh	Time	kWh
Jan-21	1:30 AM	0.87	6:30 PM	2.84	6:30 PM	2.02	12:30 AM	3.83
Feb-21	12:30 AM	0.89	12:30 AM	2.73	12:30 AM	2.02	12:30 AM	4.76
Mar-21	1:30 AM	0.96	12:30 AM	2.76	12:30 AM	2.07	12:30 AM	4.80
Apr-21	12:30 AM	1.75	12:30 AM	2.85	1:30 AM	2.18	12:30 AM	4.92
May-21	12:30 AM	2.16	12:30 AM	2.78	12:30 AM	2.32	12:30 AM	4.89
Jun-21	12:30 AM	1.79	12:30 AM	2.02	12:30 AM	2.36	12:30 AM	3.10
Jul-21	12:30 AM	1.84	12:30 AM	2.18	12:30 AM	2.52	12:30 AM	4.31
Aug-21	2:30 PM	1.80	12:30 AM	3.22	12:30 AM	2.54	12:30 AM	4.32
Sep-21	12:30 AM	1.91	12:30 AM	3.23	12:30 AM	2.61	12:30 AM	4.47
Oct-21	12:30 AM	1.72	12:30 AM	2.84	12:30 AM	2.21	12:30 AM	3.96
Nov-21	11:30 AM	1.13	12:30 AM	2.78	12:30 AM	2.12	12:30 AM	3.51
Dec-21	2:30 PM	1.04	12:30 AM	3.04	12:30 AM	2.43	1:30 AM	3.78

SDG&E Transportation Electrification Program Load Data

Please note that pursuant to the attached Report some of the information included herein is customer usage data, which is treated as confidential by law. In this instance, the program participants have affirmatively consented to the disclosure of their information as part of their participation in the program.

2021 Results

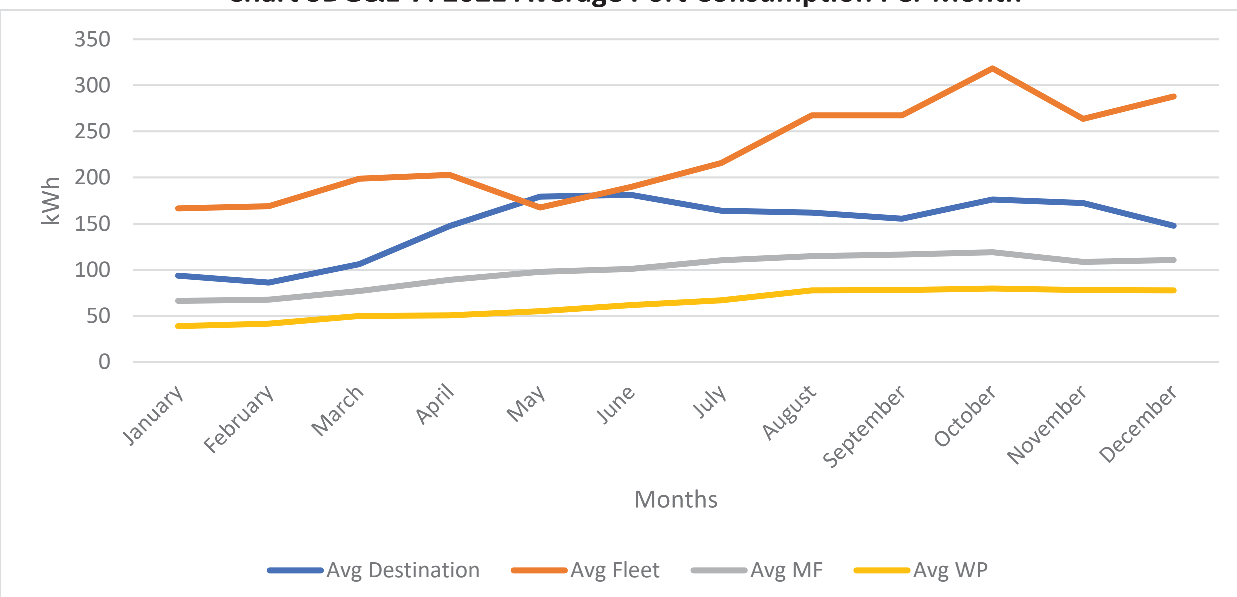
For Chart SDG&E-7 below, total energy consumption was aggregated by site segment per month and divided by the total site segment port count to create the average port consumption per month by site segment. This was done to help show continuity between systems as SDG&E transitioned from its legacy customer information system to the new system in April 2021. The team responsible for the transition ensured that the data quality was consistent from end to end (multi-year transition with tens of rounds of unit testing and approvals).

In Chart SDG&E-7, the average port consumption per month for 2021 shows a few spikes (relative maximums) in the Fleet segment around the months of March, August, and October. One large customer in the Fleet group cut their consumption significantly starting in May, while other Fleet sites seemed to invest in their fleet heavily toward the latter half of the year. The second spike in Fleet consumption is shown in August, which is due to the station count growing from 116 to 122 (5%) and the corresponding energy consumption increasing by 30% from approximately 25,034 kWh to 32,656 kWh in that same period. One site tripled their consumption from 3,715 kWh to 9,335 kWh between July and August 2021. The final spike occurred in October. This was mostly due to steady growth for all Fleet site consumption, followed by some factors in November that caused a decline in the average. These factors include:

- More holiday time in November = Fewer drivers
- Port count increase of 7% (122 to 130) without any increase of consumption
- One site consumption dropped to almost zero (steady decline from beginning of the year)

Multi-unit Dwelling (shown as MF in the below tables) and Workplace charging show consistent, steady growth throughout the year. Destination usage is consistent with warmer weather and time off; people go to the beach or park when the weather is warm enough.

Chart SDG&E-7: 2021 Average Port Consumption Per Month



2021 Hourly Results

For Charts SDG&E-8A and SDG&E-8B below, the total energy consumption was aggregated per site segment per part of week per hour. An average was then calculated by taking the summed consumption and dividing that number by the number of ports for each site segment. That quotient was then divided by the number of days in the period with the result being grouped by segment and part of week.

The weekday charging data for 2021 shown in Chart SDG&E-8A shows some interesting trends regarding the Fleet segment. The 2020 data used to peak at 3pm with consumption being 1.5x as much as the peak around midnight. There is a relative peak around 3-4pm, but the peak at midnight is 1.5x as high as the 3-4pm peak. The charging behavior has changed significantly. The weekend charging data for 2021 in Chart SDG&E-8B, shows that destination charging activity starts ramping up in the morning (8am), peaks around noon, and starts dropping in the afternoon (3pm).

Chart SDG&E-8A: 2021 Average Weekday Hourly Port Consumption

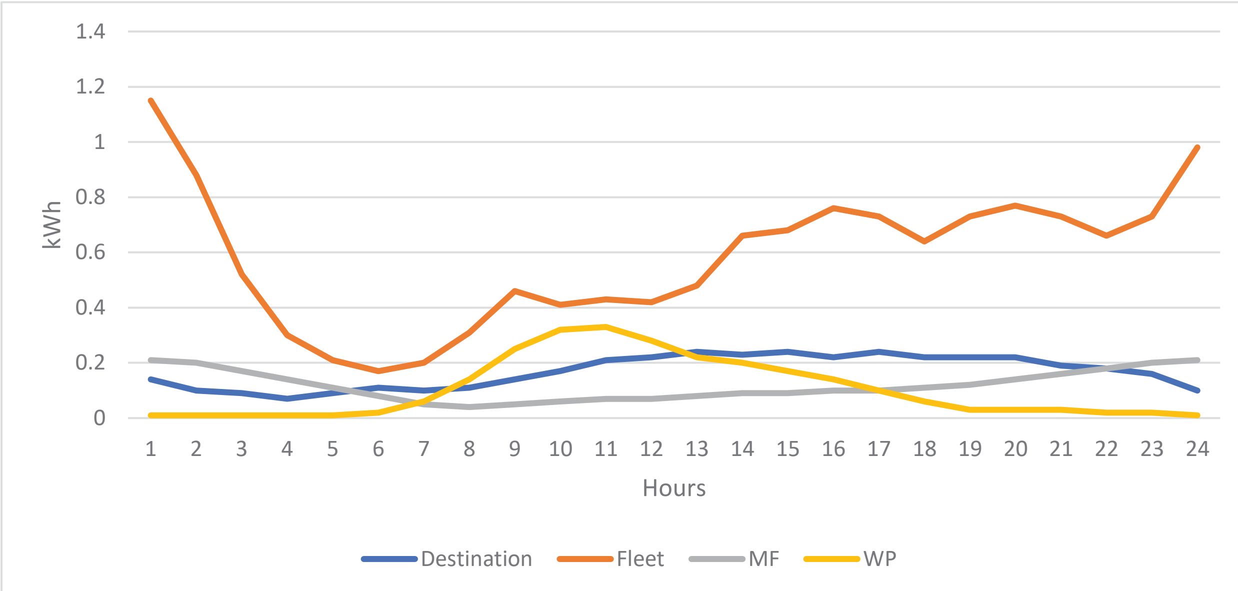
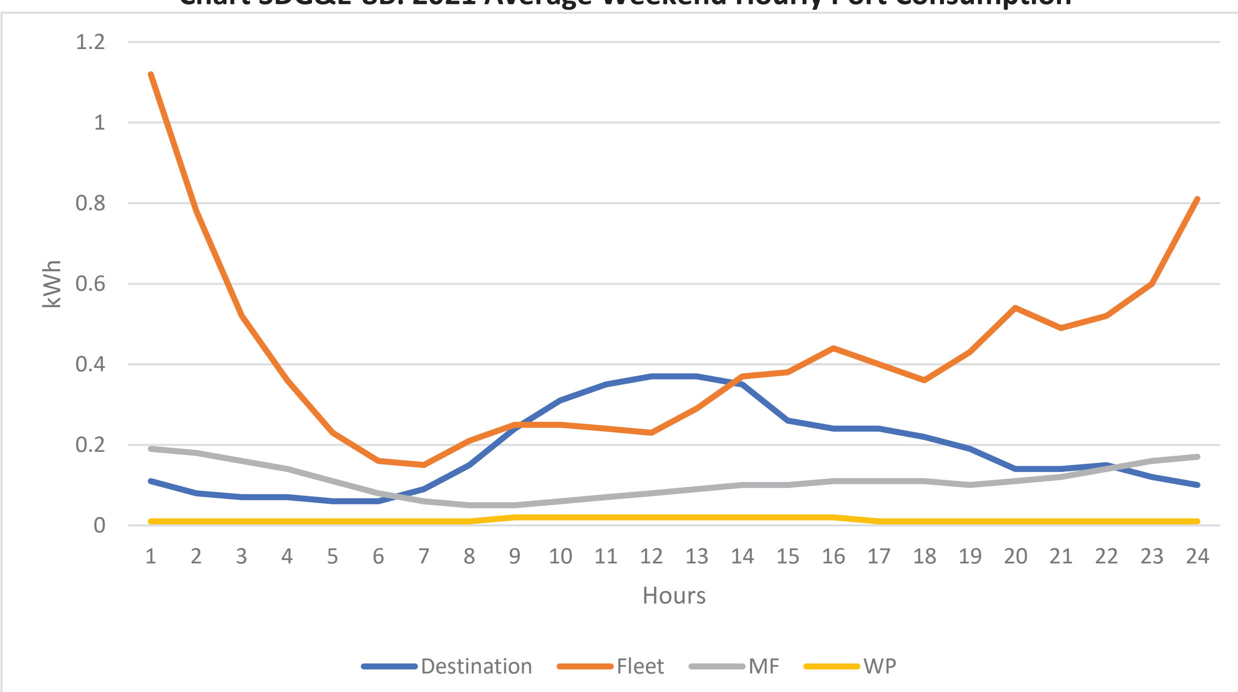


Chart SDG&E-8B: 2021 Average Weekend Hourly Port Consumption



IV. Cost Tracking Data

A. Overview and Approach

This report provides aggregated EV Charging Infrastructure cost data, by IOU. The IOUs have coordinated, to the extent possible, to provide consistency in data assumptions. However, because utilities have different methods of tracking their costs, the costs calculated for each category may be based on different assumptions. Each IOU section includes information on the general approach and assumptions for the cost data; it also explains why certain data may not be available at this time.

Additionally, this report is limited, in that it primarily includes utility-incurred costs. Traditionally, customer-side costs (behind the meter) are generally unknown to the utility unless covered by a utility TE program. As such, certain customer costs, which may be required for deploying EV infrastructure but unknown to the utility, may not be accounted for in this report. One example of this type of cost is the trenching and site excavation for service line extensions, costs that are not utility service facilities under Rules 15 and 16 and are therefore borne by customers and not tracked by the utility. Such costs are not included in this report.

Table 1 below provides a summary of the EV infrastructure costs and responsibilities, for projects outside of an IOU EV charging infrastructure program. Comparing the costs of installing EV charging infrastructure by IOU TE programs and traditional delivery (or non-program) is challenging, as the IOUs are unable to track and report on all non-program customer costs. This report includes information on those costs that are known to the IOUs.

Table 1: Summary of EV Infrastructure Costs and Responsibilities

	Customer Assigned Costs	Allowance?	Utility Assigned Costs
Equipment on Customer Side of Meter	Customer pays all costs for charging equipment, including costs to plan, design, install, own, maintain, and operate facilities and equipment beyond the Service Delivery Point		
Service Line Upgrade	• Excavation: trenching, backfilling, and other digging as required including permit fees	Yes, to cover work responsibility assigned to utility. Customer pays amount exceeding allowance. This is in	• Underground Service: service conductors and connectors

	• Furnishing, installing, owning, and maintaining all Conduits (including pulling tape) and Substructures, furnishing riser materials • Protective Structures: Furnishing, installing, owning, and maintaining all necessary Protective Structures as specified by utility for utility's facilities	addition to Customer assigned costs. Note: CPUC policy exemption in place for residential upgrades when EV load is added. Under exemption, amount exceeding allowance is not paid by customer and instead paid by utility and recovered through distribution rates. *	• Overhead Service: conductors and support poles • Metering: meters and associated utility-owned metering equipment
Secondary Lines/ Transformer Upgrade (serving 2 or more Service Lines)			Utility pays all costs for upgrading and maintaining the distribution system. Recovered through distribution rates.
* Similar additional cost coverage will be available to non-residential customers via Rule 29 which was approved by the CPUC in October 2021 and available to customers in April 2022.			

Cost data is located within Attachments 1 – 3, by IOU.[31] Attachments 1 - 3 include the following cost tables:

- Table 2: Non-Program Costs for 2021
- Table 3: Pilot-Program Costs for 2021
- Table 4: Historic Costs

The IOUs will work with the Energy Division in 2022 to continue to refine this report for the future.

[31] See Attachment 1 for PG&E data; Attachment 2 for SCE data, and Attachment 3 for SDG&E data.

B. PG&E's EV Infrastructure Cost Data

Table 2 in Attachment 1: Non-Program Costs

a. General Approach and Cost Assumptions

PG&E performed EV-related upgrade work for 60 residential charging infrastructure projects and 60 non-residential charging infrastructure projects in 2021. These only include projects that were fully invoiced during the period of January 1, 2021 through December 31, 2021 even if the project work began in 2020. Costs related to EV infrastructure installation as part of new building construction are not separately tracked and therefore not included in this report.

Upgrade costs related to EVs fall into three categories: 1) equipment on the customer side of the meter, 2) the individual customer service line, and 3) the utility distribution system that serves multiple customers. As described above, residential and non-residential customers receive an allowance for upgrade costs on the utility side of the meter and are responsible to pay any costs over the allowance. Residential PEV customers are exempt and any costs above the residential allowance are assigned to the utility per current CPUC policy. PG&E does not have information on the customer side of the meter costs and limited insight on the customer assigned costs for service line upgrades, which includes costs over the Rule 16 allowance.

It is important to note that there may be differences in how non-program costs are tracked and reported across the three IOUs and therefore it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- **Site Costs**
    - PG&E separately estimates and records the costs of specific work types of design, trenching, separate meters, permitting, distribution system work (under Rule 15[32]), and service line work (under Rule 16[33]). In this report, PG&E includes costs for projects that were fully invoiced in 2021 and uses the following definitions for the cost categories in Table 2:
        - Design – costs for all utility side of the meter design assigned to the utility or the customer,
        - Trenching and site excavation – Costs for all work related to digging and excavation to lay conduit and wires for projects. This includes costs for work completed by the utility or the customer and assigned to the utility and customer,
        - Separate meter – costs for all meters purchased for all projects and assigned to the utility or customer. This also includes estimated Separate

[32] PG&E Electric Rule 15 - https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_15.pdf
[33] PG&E Electric Rule 16 - https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_16.pdf

Meter Costs associated with TE Programs Infrastructure. These costs are included here because Separate Meter costs for EVCN and DC Fast Charge are captured under PG&E's GRC proceeding, not covered by these programs.

    - Permitting – cost of all permits necessary for work on the utility side of the meter and assigned to the utility or customer,
    - Total Distribution System Costs Incurred by Utility for Upgrades – all costs associated with work performed on the distribution system under Rule 15 including design, trenching, permitting and other materials and labor,
    - Total Service Line Costs Incurred by Utility for Upgrades – all costs associated with work performed on the service line under Rule 16 including design, trenching, permitting, meters, and other materials and labor,
    - Total Utility side costs – all costs assigned to the utility for work associated with the EV-related upgrade including Rule 15 and Rule 16 costs, grid betterment work, the allowance and costs above the allowance for residential customers, and
    - Total Customer side costs – all costs assigned to the customer for work performed on the utility side of the meter that PG&E has insight into (e.g. service line trenching, backfilling, and other digging as required including permit fees; furnishing, installing, owning and maintaining all conduits and structures, including riser material, and all rights of way costs, if applicable). The utility or the customer may have performed the work. For residential customers this includes any cost above the allowance even though this is assigned to the utility under the CPUC policy exemption.

- **Other (Ports Installed/New Capacity):**
    - The capacity reported under "Amount of new capacity resulting from project (kW)" reflects the new capacity added as reflected in customer applications for Non-pilot/program Residential and Commercial Charging Infrastructure.
    - For Residential Charging Infrastructure capacity, 41 of the 60 residential infrastructure projects reported did not explicitly state the amount of new capacity added. They did include, however, information on the type of charger and the number of ports for each project. Therefore, PG&E made an estimation of 7.2 kW of added capacity for each of those 41 residential projects
- The methodology is the same for recording of costs of both residential and commercial charging infrastructure non-program work.

b. Explanation of why certain data is unavailable to report

- For Total Customer side costs, PG&E is only able to report on costs assigned to the customer for work on the utility side of the meter that PG&E has insight into. There may be some additional costs for work on the utility side of the meter assigned to the customer that is not reported here. Total customer side costs also do not include costs for the behind-the-meter work performed by the customer.

c. Explanation of plans to provide additional data in future reports

- PG&E and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified in the future.

d. Explanation of why Total Utility Side Costs and Total Customer Side Costs do not match the sum of all other categories

- The Total Utility Costs and Total Customer Side Costs do not match the sum of all other categories because some costs accrued do not fit within any of the subcategories as presented (Design Costs, Trenching, Separate Meter Costs, Permitting, Total Distribution, Total Service Line). These include:
    - Mapping: labor for recording project “as-builts” in mapping records to ensure accuracy of asset records
    - Inspection: any work done by the customer on behalf of PG&E needs to be inspected by PG&E.
    - Land: preparation for land rights and easements that PG&E performs on behalf of the customer, which the customer pays for.
    - Administrative Overhead: overhead to cover back office administrative functions.
    - Project Management: labor costs for managing the project from point of application to execution of construction.

<u>**Table 3 in Attachment 1: Program Costs**</u>

a. General Approach and Cost Assumptions

PG&E includes costs for projects in 2021[34] across six programs – EV Charge Network (EVCN), EV Fleet, EV Fast Charge, and three Priority Review Projects (Medium-Heavy Duty Fleet Demonstration Project, Idle Reduction Project, and Electric School Bus Renewables Integration Project). EVCN fully invoiced 50 completed projects in 2021. This included 20 projects at Multi Unit Dwelling (MUD) sites delivering 832 ports, and 30 sites at workplaces (WP) delivering 953 ports. EV Fleet fully invoiced 15 completed projects in 2021, including 14 Small Sites serving a total of 117 vehicles and 1 Medium Site serving 10 vehicles. EV Fast Charge fully invoiced 4 sites in 2021. The PRP projects have all been substantially completed and did not accrue additional site costs during 2021. They did report support activities costs and other costs, however, and these costs are included in Attachment 1.

Reported costs are not tracked in this report by individual program. Instead, costs are categorized by Light Duty Vehicle (LDV) Infrastructure and Medium and Heavy Duty (MD/HD) Infrastructure. Light Duty Infrastructure is further subcategorized by L2 MUD, L2 Workplace infrastructure, and DCFC infrastructure. DC Fast Charge infrastructure falls under the LDV category, but DCFC has its own column to show costs associated with the DCFC program. MD/HD is segmented by the capacity that a given site adds to accommodate charging equipment installations: Small – installed charging capacity adds up to 500 kW, Medium – between 500 kW and 3 MW, and Large – beyond 3MW. Among EV Fleet's 15 projects, 14 were small sites that added a total of 2,104 kW of new capacity, and 1 was a medium site that added a total of 1,284 kW of new capacity. PRP projects align with the small site category but did not add new infrastructure and consequently new capacity during 2021.

It is important to note that there may be differences in how program costs are tracked and reported across the three IOUs and it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- **Site Costs:**
    - In 2021, PG&E's site costs included projects that were fully invoiced[35] across the EVCN, EV Fast Charge, and EV Fleet programs. PG&E records each project's site costs and uses the following definitions for the cost categories in Table 3:

[34] Some costs represented in Table 3 in Attachment 1 for TE Programs represent costs for projects that were fully invoiced within 2021 (which, therefore, PG&E has full insight into actual costs for); these costs may include costs incurred for projects whose design, construction, and activation timeline spanned multiple calendar years, and therefore some costs for the projects represented in this table may have been incurred in years prior to 2021. For this reason, it would not be possible to simply add costs from consecutive EV Load and Charging Cost Reports by TE Program and arrive at a mutually exclusive sum of program costs. Other costs represented in Table 3 in Attachment 1 represent those costs that were incurred within calendar year 2021 for that cost category.

[35] Fully invoiced indicates that PG&E had full actual cost data because third-party vendor invoices were completed. This is different from "substantially completed", which for light-duty vehicle infrastructure is

- Design – utility costs for all final site designs for projects,
- Trenching and site excavation – estimated costs for all utility work related to digging and excavation to lay conduit and wires for projects fully invoiced in 2021. This does not include restoration costs,
- Separate meter – estimated total costs for all meter panels, associated equipment, and installation costs for all projects,
- Permitting – estimated costs associated with permits and labor to apply for permits,
- Total Utility side costs - "to the meter" construction costs (including trenching), as well as estimated materials and design costs, and
- Total Customer side costs – "behind the meter" construction costs (including trenching), as well as estimated materials, design, and permitting costs but excluding charger costs, participation payments, and rebates where applicable.

- The categorization is generally the same for the recording of Light Duty and Medium- and Heavy-duty site costs.
- With the exception of Total Utility side costs and Total Customer side costs, "Site Costs" do not include project management costs and rebates.
- The specific site costs of design, trenching, separate meters, and permitting are a subset of the total utility side costs and total customer side costs reported for projects fully invoiced in 2021.

- **Support Activities Costs**
  - Support Activities costs are reported for work done in the 2021 calendar year and are in many cases not tracked to specific project sites[36]. In 2021, PG&E Support Activities costs included reported costs for all programs. PG&E uses the following definitions for the cost categories in Table 3:

[36] A portion of project management costs are associated with the specific projects fully invoiced in 2021. Some project management costs and the remaining two support activities cost categories are not directly associated with projects fully invoiced in 2021 (i.e. these could include projects that were worked on in 2021 but not fully invoiced in 2021).

- Project management – all labor costs associated with project management for projects fully invoiced[37] during 2021,

- Customer outreach – all costs associated with customer outreach before contract was signed on any given project, with reported costs representing spend in this category in 2021,

- Outreach and education materials – all costs for program marketing, including collateral, website development, and events spent in 2021, and

- Other costs – these include rebates for various programs and non-capital costs related to software and hardware integration for the Medium/Heavy Duty Customer Fleet Demonstration Pilot. Specifically, rebates under Medium and Heavy-Duty Infrastructure are primarily from EV Fleet. Those rebate costs include all infrastructure incentives and rebates associated with EVSE equipment that were issued during the 2021 calendar year. These rebates and incentives may have been issued to sites that were fully invoiced before 2021 because site hosts must submit invoices as proof of costs incurred in order to receive payment, and this may occur several months after a site has been completed.

- Other Costs – also include rebates for Priority Review Projects. Due to construction and interconnection related delays, there are continued activities to close out the original scope of work for the Medium- or Heavy-Duty Fleet Customer Demonstration PRP.

- Other (Ports Installed/New Capacity):

    - Ports captured under Medium- and Heavy-Duty Infrastructure are primarily from PG&E's EV Fleet Program. The ports reported under this category reflect "committed" ports, not "activated" ports. The Fleet Program differs from other TE programs because site hosts can acquire and install EVSEs over a 5-year period instead of at site activation. This means that the number of ports activated for these 15 sites may change over time as site hosts install additional equipment.

b. Explanation of why certain data is unavailable to report

[37] Fully invoiced indicates that PG&E had full actual cost data because third-party vendor invoices were completed. This is different from "substantially completed", which for light-duty vehicle infrastructure is defined as projects where all customer side or "behind the meter" (BtM) construction work is complete (excluding charger installation), and all utility side or "to the meter" (TtM) equipment is installed (excluding to the meter wire pulls or energization). Projects substantially completed in 2021 may include projects that in 2021 had not yet completed charger installation or site restoration.

Some cost data from the programs was not available to report. There are different reasons depending on the cost category, and it may also vary between programs. PG&E provides detail on some of the specific data that is unavailable to report below:

- Light Duty Vehicle Infrastructure
  - Design, permitting, and trenching costs are recorded as part of broader cost categories. As a result, these costs have been estimated using contractor submission data.
  - Additionally, design, materials, overheads, and permitting costs are not separately recorded for utility side work and customer side work. As such, the provided costs are prorated between utility side costs and customer side costs based on estimated utility side vs customer side construction labor allocations.
  - In other instances, costs are not consistently separately recorded for each project site in a way that is easily aggregated, and often require manual tabulation/estimation for Light Duty Vehicle Infrastructure, e.g.:
    - Separate meter costs are estimated based on the number of meter panels installed at each project site and an estimated unit price for meter panels, associated equipment, and installation costs.
    - Permitting costs are estimated based on the costs of the labor to apply for the permit, and the permit costs.
  - There was an additional PRP, but that was not an infrastructure pilot, so we do not include any infrastructure costs for it in this report.
  - DCFC Load Data is not included in this report as there are too few sites
- Medium and Heavy-Duty Vehicle Infrastructure
  - Site costs include only to-the-meter costs as there was no infrastructure construction behind the meter in projects fully invoiced in 2021.
- PG&E does not separately record distribution system upgrade costs or service line upgrade costs related to EV infrastructure installation through programs. Costs incurred to the utility for any work on the distribution system or service line in the programs are considered to-the-meter costs and are captured under total utility side costs.

c. Steps to report currently unavailable data at a later time

- PG&E is working to be able to provide more granular cost actuals for permitting, trenching, and separate meters for infrastructure constructed in 2021 for certain programs[38] by revising the process and structure of contractors' cost reporting and invoicing and tracking those specific cost components through new software tools. This additional data may be included in future reports.

d. Explanation of plans to provide additional data in future reports

- PG&E and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified during program deployment.

<u>**Table 4 in Attachment 1: Historic Costs**</u>

a. General Approach and Cost Assumptions

- **Non-program Charging Infrastructure costs:**
    - Historic non-program residential charging infrastructure costs from 2011-2018 are pulled from data used in previous Load Research Reports and 2020 costs are pulled from the EV Infrastructure Cost Report submitted in 2021.
        - The process to report utility distribution and service line costs for this Report is different than for previous Load Research Reports and may make a comparison between tables challenging.
    - Historic non-program commercial charging infrastructure costs were first included for 2020 projects and the data is pulled from Table 3 in Attachment 1 of the EV Infrastructure Cost Report filed on April 1, 2021.
    - Historic program infrastructure costs were first included for 2020 projects and the data is pulled from Table 2 in Attachment 1 of the EV Infrastructure Cost Report filed on April 1, 2021.
    - As mentioned in the section on Table 2 of attachment 1, upgrade costs related to EVs fall into three categories: 1) equipment on the customer side of the meter, 2) the individual customer service line, and 3) the utility distribution system that serves multiple customers.
    - PG&E does not have information on the customer side of the meter costs nor insight on all the customer assigned costs for service line upgrades.
        - The Customer pays all costs for beyond the Service Delivery Point.

[38] Excludes EVCN, for instance.

        - The Customer is responsible for trenching, backfilling, and other digging as required including permit fees.
        - The Customer is responsible for furnishing, installing, owning and maintaining all conduits and structures, including riser material.
        - The Customer is responsible for all rights of way costs, if applicable.
    - Per the CPUC policy exemption currently in place, when the Rule 16 costs exceed the allowance provided for residential EV service line upgrades, the amount exceeding the allowance is not paid by the customer, but instead by PG&E (recoverable through distribution rates).

b. Explanation of why certain data is unavailable to report

- N/A

c. Steps to report currently unavailable data at a later time

- N/A

d. Explanation of plans to provide additional data in future reports –

- PG&E will work with Energy Division and the other IOUs to determine how future historical (i.e. reporting periods 2019 and beyond) will be organized on future reporting templates.

C. SCE's EV Infrastructure Cost Data

<u>Table 2 in Attachment 2: Non-Program Costs (Nominal Costs)</u>

a. General Approach and Cost Assumptions

In addition to SCE's TE programs and pilot activities, SCE completed Non-Program, EV-related infrastructure work for 2 residential charging infrastructure projects and 78 non-residential charging infrastructure projects in 2021. SCE is only reporting on projects, for which construction was completed between January 1, 2021, and December 31, 2021. Regardless of the year the project originated, all costs associated with a project completed in 2021 are included in this report. Costs related to EV infrastructure installation conducted as part of new building construction are not separately tracked and therefore not included in this report.

Non-program infrastructure costs related to EVs fall into two categories: (1) the utility distribution system that serves multiple customers (Rule 15), and (2) the individual customer service line (Rule 16). In this report, EV infrastructure is accounted for only if a work order is opened and identified as an EV work order. The cost reporting methodology is the same for the recording of costs for both residential and commercial charging infrastructure non-program work.

Residential and non-residential customers receive an allowance for upgrade costs on the utility side of the meter. Customers are responsible to pay any costs over the allowance. Per the CPUC Administrative Law Judge's Ruling issued on November 23, 2020, in Rulemaking 18-12-006, all residential service facility upgrade costs in excess of the residential allowance required to accommodate Basic Plug-In-Hybrid and Electric Vehicle Charging Arrangements shall be treated as common facility costs rather than being paid for by the individual plug-in hybrid and electric vehicle customer until December 31, 2021.

There are differences in how non-program costs are tracked and reported across the three IOUs and it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- **Site Costs**
    - If applicable, SCE separately estimates and records the costs of specific types of work including trenching, separate meters, permitting, distribution system work (Rule 15), and service line work (Rule 16). In this report, SCE includes costs for projects where construction was completed in 2021 and uses the following definitions for the cost categories in Table 2:
        - Design Costs – To report design costs on the utility side of the meter, SCE used the historical recorded Planning and Design costs within Distribution for 2021 that were allocated to all distribution capital orders, which equates to 12.4%.
        - Trenching and site excavation – estimated costs, if performed by the utility, for all utility-side work related to excavation and installation of underground ducts and structures required for projects.
        - Separate meter – estimated costs are provided only for projects completed in 2021. To better estimate meters, SCE is providing site level estimated meter costs from our design system. Generally, SCE purchases its meters in bulk, rather than for individual work orders. Actual meter costs are recorded in mass plant and capitalized when received. Meter costs are not recorded against program budget.
        - Permitting – estimated costs of all utility invoiced permits necessary for work on the utility side of the meter.
        - Total Distribution System Costs Incurred by Utility for Upgrades – The number provided, a combination of both actual and estimated dollars, represents the total utility side (to the meter) expenditure for all capital direct costs, indirect capital labor overhead recorded costs and O&M indirect labor costs, up to but not including the meter pedestal or meter panel associated with work performed to install

distribution line extensions, Rule 15, and combination distribution line extension and service line extension, Rules 15 and 16, non-program EV work. Cost categories include, for example, trenching, permitting, meter costs, and other material (including transformation costs), and labor, as well as division overhead costs.

  - Includes division overhead costs (e.g., planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g., pension, benefits, etc.).
  - Includes estimated O&M labor indirect costs. SCE can only provide estimated O&M labor indirect costs because these costs are authorized in SCE's GRC (General Rate Case), and are separately recorded in the Pension, Medical, and PBOB Balancing Accounts. O&M pension & benefits do not follow the program accounting.
  - Transformers sized at or less than 500 kVA are estimated costs. Transformers sized greater than 500 kVA are specialty items that SCE orders and charges directly to the work orders.

- Total Service Line Costs Incurred by Utility for Upgrades – The number provided, a combination of both actual and estimated dollars, represents the total utility-side (to the meter) expenditure for all capital direct costs and indirect labor overheads recorded costs, up to but not including the meter pedestal or meter panel for completed projects within the reporting period, for work performed to install service line extensions, Rule 16, non-program EV work. Cost categories include, for example, trenching, permitting, meter costs, and other material (including transformer cost) as well as division overhead.
  - Includes division overhead costs (e.g., planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g., pension, benefits, etc.).
  - Includes estimated O&M labor indirect costs. SCE can only provide estimated O&M labor indirect costs because these costs are authorized in SCE's GRC, and are separately recorded in the Pension, Medical, and PBOB Balancing Accounts. O&M pension & benefits do not follow the program accounting.
  - Transformers sized at or less than 500 kVA are estimated costs. Transformers sized greater than 500 kVA are specialty items that SCE orders and charges directly to the work orders.

        - Total Utility side Costs – total of all Distribution System costs, and Service Line costs incurred by the Utility for non-program EV work.
        - Total Customer side costs – all costs invoiced to and paid by the customer for work performed on the utility side of the meter that SCE has insight into (e.g., riser material, all rights of way costs, and tax, if applicable).
            - For residential customers this also includes any cost above the allowance even though this is assigned to the utility under the CPUC policy exemption.

b. Explanation of why certain data is unavailable to report

- Projected ongoing maintenance costs for utility-side infrastructure (Table 2)
    - Per Joint IOU conversation with the Energy Division on January 10, 2022, the utility has removed reporting of Projected ongoing maintenance costs for utility-side Non-programs Cost table 2 due to the IOUs not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs on a single structure/piece of equipment.
- Non-Program Costs (Table 2)
    - Per Joint IOU conversation with Energy Division on January 10, 2022, SCE has removed Project management, Customer outreach (labor), Marketing and education materials, and other costs from the Non-Programs Cost table 2 as these categories are not applicable.
- SCE has not previously tracked commercial port counts. This requires a change to our tracking system, which SCE has made, effective January 1, 2022. Reporting will be available beginning March 31, 2023.

c. Steps to report currently unavailable data at a later time

- SCE began tracking commercial port counts beginning January 1, 2022, with reporting to follow in 2023.

d. Explanation of plans to provide additional data in future reports

- SCE and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified in the future.

<u>**Table 3 in Attachment 2: Pilot-Program Costs (Nominal Costs)**</u>

a. General Approach and Cost Assumptions

SCE is providing costs for its TE pilots and programs that were completed[39] between January 1, 2021, and December 31, 2021. Regardless of the year the project originated, all total capital costs associated with a project completed in 2021 are included in Site Costs ($) category Table 3. With the exception of rebates, SCE does not track O&M costs per site/project. In the Support Activities ($) Table 3, all program O&M 2021 recorded costs are provided and grouped into their respective categories.

The light-duty vehicle (LDV) programs that incurred Capital costs in 2021 include Charge Ready Pilot & Bridge. LDV programs that incurred O&M costs in 2021 include Charge Ready Pilot & Bridge, Charge Ready Schools (AB 1082), Charge Ready Parks and State Beaches (AB 1083), and Charge Ready Light-Duty. Charge Ready Transport is the only medium- and heavy-duty vehicle (MDHD) program that incurred both Capital and O&M costs in 2021. In 2021, SCE Light-Duty Vehicle Infrastructure completed projects at 17 Multi-Unit Dwelling sites with 178 ports, 9 Workplace sites with 373 ports, 4 Destination Centers with 253 ports, and 1 Fleet with 10 ports. Within the Medium- & Heavy-Duty Vehicle Infrastructure segment, SCE completed projects at 13 small sites with 88 ports. SCE tracks MDHD program goals based on vehicles electrified and not based on port count. As such, there were 135 MDHD vehicles electrified for 13 small site~~s~~.

SCE records each project's site costs in separate work orders for:

- Utility-side costs ("to the meter" capital labor and contract construction costs, including design, trenching, permitting, etc.) and
- Customer-side costs ("behind the meter" capital labor and contract construction costs, from the meter to the stub-out for the charging equipment, design, trenching, permitting, etc.)

The methodology is the same for the recording of Light-, Medium- and Heavy-duty construction costs. This methodology will also be consistent with the Charge Ready Schools (AB 1082), Charge Ready Parks and State Beaches (AB 1083), and Charge Ready Light-Duty.

- **Site costs** – Includes only Capital costs.
    - Design costs will include both utility-side and customer-side costs.
        - Utility-side: To report design costs on the utility side of the meter, SCE used the historical recorded Planning and Design costs within Distribution for 2021 that were allocated to all distribution capital orders, which equates to a 12.4%. The 12.4% was applied against the EVSE work orders to estimate Design costs.
        - Customer-side: The number provided represents the actual labor and material dollars required to produce the customer-side (behind or beyond the meter) design from meter pedestal up to, but not including the EVSEs. This includes, for example, site visits, research, and design production. SCE is able to provide these customer-side costs due to the implementation of

[39] Pilots and program costs are included for completed sites with rebates paid, where applicable, as of December 31, 2021.

third-party contracts with Architecture and Engineering firms for design work.

- Trenching and site excavation and permitting costs provided in the Site Costs section are only customer-side costs. These costs are estimates based on overall program allocations.
  - Trenching and site excavation – Number provided represents the actual labor and material dollars required for excavation, installation of customer-side (behind or beyond the meter) conduits and structures (e.g., handholes, transformer pads, vaults, etc.) and site restoration.
  - Permitting costs – Total actual costs for customer-side (behind or beyond the meter) permitting costs charged by the Authority Having Jurisdiction (AHJ)
- Separate meter costs are provided for only projects that were completed in 2021. To better estimate meters, SCE is providing site level estimated meter costs from our design system. SCE generally purchases its meters in bulk, rather than for individual work orders. Actual meter costs are recorded in mass plant and capitalized when received. Meter costs are not recorded against program budget.
- Total Utility-side costs - The number provided, a combination of both actual and estimated dollars, represents the total utility-side (to the meter) expenditure for all capital direct costs and indirect labor overheads recorded costs, up to but not including the meter pedestal or meter panel for completed projects within the reporting period, separated by respective programs. Cost categories include, for example, trenching, permitting, meter costs, and other material (including transformer cost) as well as division overhead.
  - Includes division overhead costs (e.g., planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g., pension, benefits, etc.).
  - Transformers sized at or less than 500 kVA are estimated costs. Transformers sized greater than 500 kVA are specialty items that SCE orders and charges directly to the work orders.
- Total Customer side costs - The number provided, a combination of both actual and estimated dollars, represents the total customer-side (behind or beyond the meter) expenditure for all capital direct and indirect labor overheads recorded costs, from the meter pedestal or meter panel, up to but not including the EVSEs for completed projects within the reporting period (programs with Own and Operate offerings will include EVSE costs). Examples of included costs are design, trenching, permitting, labor, and material such as the meter pedestal or meter panel, transformation, cable, and connectors.
  - Includes division overhead costs (e.g., Planner activities such as site visits, creating the design and operations activities such as scheduling work,

staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g., pension, benefits, etc.).

- **Support Activities** – Includes both Operation and Maintenance "O&M" and Capital expenses
  - Project Management
    - Program-related direct labor such as program management and program support
  - Customer Outreach (Labor) - Labor costs associated with conducting Transportation Electrification Advisory Services (TEAS) provides business customers with a dedicated "one-stop shop" for specialized education, awareness, and support on TE issues. The goal of TEAS is to promote customer adoption of TE, help with pre-planning activities, generate leads for TE programs (active or in development) and serve the TE needs of our business customers.
  - Marketing and Education Materials
    - Marketing, Education & Outreach (ME&O) – Includes third-party costs associated with the development and implementation of customer education and marketing campaigns and materials that are primarily targeted at potential multifamily and non-residential EV and EV charging adopters through educational webinars, fleet fueling calculator, Charge Ready Transport case studies (customer feedback), paid media ads, print collateral and promotional items, web design and content development, email marketing, industry research and data, and targeted industry group membership.
    - EV Awareness – Includes third-party costs associated with the development and implementation of EV Awareness campaigns, which use mass media, direct marketing, outreach to local community organizations, and an EV ambassador network to encourage EV awareness and target customers in multiunit dwellings (MUDs), disadvantaged communities (DACs) through the SCE Cars tool with vehicle & incentive information, residential EV web content, community engagement events, promotional materials, and advertising.
  - Other Costs
    - This category includes various costs not captured in the above categories, for example, rebates, canceled project costs, Capital IT implementation costs, and estimated O&M labor indirect costs. SCE can only provide estimated O&M labor indirect costs because these costs are authorized in SCE's GRC and are separately recorded in the Pension, Medical, and PBOB Balancing Accounts. O&M pension & benefits do not follow the program accounting.

- **Other Support Activity**

   - Total number of charge ports installed – total completed project port count based on information provided by the customer at project application/acceptance
   - Amount of new capacity resulting from project (kw) - Total estimated capacity based on information provided by the customer at project application/acceptance

b. Explanation of why certain data is unavailable to report

- SCE program accounting is not able to break down utility-side site excavation and trenching and permitting costs into separately recorded entries. As such the totals indicated in Attachment 2 Table 3 site excavation and trenching and permitting are only for customer-side costs, which are estimated based on overall program allocations. However, these costs are reported within the division overhead charges which are included in the Total Utility-side Costs.

c. Steps to report currently unavailable data at a later time

- SCE has taken steps to ensure more detailed tracking of costs by creating separate work orders per site for utility-side costs, customer-side costs, and easements. Within these work orders, SCE uses cost elements, cost descriptions, and purchase order information to further breakdown costs into additional subcomponents. An example of steps taken from 2019 to 2021 include new contracts to provide actuals for permitting and design for customer-side costs.
- SCE will continue to review our current capital reporting structure and look for ways to improve cost recording to separate site excavation and trenching costs for both utility and customer side.

d. Explanation of plans to provide additional data in future reports –

- SCE plans to work with the Energy Division to refine this report for the future, and as part of that process will consider how to best capture the data needs requested.

<u>Table 4 in Attachment 2: Historic Costs (Nominal Costs)</u>

a. General Approach and Cost Assumptions

- Years 2011-2018 historic residential costs are pulled from data used in previously submitted Load Research Reports.

   - The template to report utility distribution and service line costs for this Report is different than for previous Load Research Reports and may make a comparison between tables challenging.
- Year 2019 historic costs are pulled from data provided in the previously submitted 2020 EV Charging Infrastructure Cost Report.[40]
- As mentioned previously, upgrade costs related to EVs fall into three categories: 1) equipment on the customer side of the meter, 2) the individual customer service line, and 3) the utility distribution system that serves multiple customers. In this report, EV infrastructure is accounted for only if a work order is opened and identified as an EV work order.
- For non-program EV charging infrastructure, SCE does not have information on the customer side of the meter costs nor insight on the customer assigned costs for service line upgrades.
   - The Customer pays all costs for beyond the Service Delivery Point.
   - The Customer is responsible for trenching, backfilling, and other excavation as required, including permit fees.
   - The Customer is responsible for excavation and installation of all ducts and structures, as well as owning and maintaining these facilities on private property.
   - The Customer is responsible for all rights of way costs, if applicable.
- Per the CPUC policy exemption currently in place through December 31, 2021, when the Rule 16 costs exceed the allowance provided for residential EV service line upgrades, the amount exceeding the allowance is not paid by the customer, but instead by SCE (recoverable through distribution rates).

b. Explanation of why certain data is unavailable to report

- N/A

c. Steps to report currently unavailable data at a later time

- N/A

d. Explanation of plans to provide additional data in future reports –

- SCE will work with Energy Division and the other IOUs to determine how future historical (I.e., reporting periods 2019 and beyond) will be organized on future reporting templates.

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[40] *See* Attachment 2, Table 4, Note 2.

D. SDG&E's EV Infrastructure Cost Data

Table 2 in Attachment 3: Non-Program Costs

General Approach and Cost Assumptions

Costs provided for all fully invoiced projects as of December 2021 and include direct costs, overheads, and Allowance for Funds Used During Construction (AFUDC) incurred for completed sites during the project life.

- Design costs: Overhead costs specifically related to engineering. Design costs are not direct charged to non-program sites
- Trenching and site excavation: estimated 25% allocation of costs from line "Total distribution system costs incurred by utility for upgrades" and "Total service line costs incurred by utility for upgrades"
- Separate meter costs: charges billed to FERC 370 – Meters
- Permitting costs: utility permits are not tracked separately
- Total distribution system costs incurred by utility for upgrades: labor, services, materials, and associated overheads for distribution system upgrades
- Total service line costs incurred by utility for upgrades: charges billed for construction of new service lines
- Total utility side costs: Includes accumulated depreciation, miscellaneous expenses and the sum of the above utility costs
- Total customer costs: required customer payments (contributions in aid of construction) made to utility

There are differences in how non-program costs are tracked and reported across the three investor-owned utilities (IOUs) and it is necessary to take into account the differences and caveats explained in this Report when comparing the cost tables.

Explanation of why certain data is unavailable to report

Permits pulled by the utility are not generally applicable to the utility's scope for residential work. Permit costs for commercial sites vary by local jurisdiction. SDG&E has estimated the average permit costs to be approximately $1,000 per site in past studies.

Per joint IOU conversation with Energy Division on January 10th, 2022, SDG&E has removed Project management, Customer outreach (labor), Marketing and education materials, and Other costs from the Non-Programs Cost table 2 as these categories are not applicable. SDG&E has also removed Projected ongoing maintenance costs for utility-side infrastructure due to not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs on a single structure/piece of equipment.

Steps to report currently unavailable data at a later time

N/A

Explanation of plans to provide additional data in future reports

SDG&E will work with Energy Division and the other IOUs to determine how future historical data will be organized and reported in future reports / templates.

Table 3 in Attachment 3: Pilot-Program Costs

General Approach and Cost Assumptions

Costs provided for all fully invoiced projects as of December 2021 and include direct costs, overheads, and AFUDC incurred for completed sites during the project life

- Design costs: Direct charges billed design cost
- Trenching and site excavation: Direct charges billed for trenching and site excavation
- Separate meter costs: Charges billed to FERC 370 – Meters
- Permitting costs: Direct charges billed for permit cost
- Total utility side costs: Total cost for labor, services, materials, and associated overheads for distribution system upgrades and new service lines, as well as accumulated depreciation, miscellaneous expenses, and the sum of the above costs
- Utility side cost versus customer side cost: Determined by construction estimate

Explanation of why certain data is unavailable to report

Costs for SDG&E's AB1082/1083 programs (Power Your Drive for Schools, Parks, and Beaches) are not available yet as construction was not completed on any sites in 2021.

Per joint IOU conversation with Energy Division on January 10th, 2022, SDG&E has removed Total Distribution System Costs Incurred by Utility for Upgrades, Total Service Line Costs Incurred by Utility for Upgrades from the Programs Cost table 3 as these categories are not applicable. SDG&E has also removed Projected ongoing maintenance costs for utility-side infrastructure due to not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs on a single structure/piece of equipment.

Steps to report currently unavailable data at a later time

N/A

Explanation of plans to provide additional data in future reports

SDG&E will work with Energy Division and the other IOUs to determine how future historical data will be organized and reported in future reports / templates.

Table 4 in Attachment 3: Historic Costs

General Approach and Cost Assumptions

Costs provided are direct costs, overheads, and AFUDC incurred for completed sites during the year.

- Historical upgrade cost from previously submitted Load Research Reports periods 2012-2018

- 2019 Historical upgrade costs based on actual cost incurred for customer upgrade jobs completed in 2019
- 2020 Historical upgrade costs based on amended submittal December 13, 2021

Explanation of why certain data is unavailable to report

N/A

Steps to report currently unavailable data at a later time

N/A

Explanation of plans to provide additional data in future reports

SDG&E will work with Energy Division and the other IOUs to determine how future historical data will be organized and reported in future reports / templates.

ATTACHMENT 1

V. Attachment 1 – PG&E

PG&E

Table 1: Number of EVs forecasted In IOU Service Territory

		Light-Duty	Medium/ Heavy Duty
Actual[1]	2011		
	2012		
	2013		
	2014	52,527	
	2015	78,574	
	2016	108,153	
	2017	140,667	384
	2018	197,367	472
	2019	242,952	552
	2020	274,518	782
	2021	331,188	937
Forecasted[2]	2022	446,901	1,203
	2023	557,942	1,570
	2024	700,472	2,278
	2025	883,644	3,544
	2026	1,125,451	5,718
	2027	1,428,018	9,234
	2028	1,793,283	14,582
	2029	2,217,556	22,270
	2030	2,696,513	32,791

Notes:

[1] Actual LDV values are provided by the Electric Power Research Institute ("EPRI"). Both Light Duty and Medium/Heavy Duty (MHD) data reflects vehicles-in-operation, however there is significant general uncertainty about the number of "actual" MHD vehicles in operation in CA. The underlying state-level data was provided by the California Energy Commission. PG&E then prorated the data to represent PG&E's service area.

[2] Forecasted values from PG&E's 2022 EV adoption forecast (Jan 2022). PG&E's light-duty (Classes 1-2a) and medium and heavy-duty (Classes 2b-8) electric vehicle long-term forecast derives from PG&E's market- and policy-driven probabilistic model. The model integrates different scenarios meeting the state's Zero-Emission goals (e.g. SB1014, Gov. Brown's EO-B-48-18, Gov. Newsom's EO-N-79-20). PG&E's 20-year forecast predicts electric vehicle population by class and segment (including rideshare vehicles), energy demand, and hourly load. It tracks electric vehicle sales in California (sources: EPRI, CEC) and market trends (source: BNEF, others) and includes current and future programs and regulations (CARB, CPUC, CEC). PG&E leverages internal data and results from pilot programs directed by state agencies and conducted in collaboration with other IOUs and vehicle manufacturers. PG&E's EV adoption forecast is subject to variables and assumptions regarding EV market demand, evolution, and development that are outside PG&E's control; therefore, the forecast is subject to significant uncertainty and should not be relied upon as a point estimate for policy or planning beyond the current PG&E GRC and distribution planning periods.

PG&E

Table 2: Non-Program Costs

2021 EV-related Upgrade Costs		Residential Charging Infrastructure	Non-program Commercial Charging Infrastructure
Site Costs ($)	Design costs	$95,445	$39,576
	Trenching and site excavation	$144,728	$3,185,604
	Separate meter costs	$4,170	$124,127
	Permitting costs[3]	$2,100	$13,179
	Total Distribution System Costs Incurred by Utility for Upgrades	$468,613	$4,121,638
	Total Service Line costs Incurred by Utility for Upgrades	$28,559	$2,544,112
	Total Utility side costs[4]	$737,111	$8,797,973
	Total Customer Costs[5]	$137,774	$1,717,284
Other	Total number of charge ports installed	64	320
	Amount of new capacity resulting from project (kW)	552	49,608

Notes:

1. Per Joint IOU conversation with Energy Division on January 10th 2022, PG&E has removed Project management, Customer outreach (labor), Marketing and education materials, and Other costs from the Non-Programs Cost table 2 as these categories are not applicable.

2. Per Joint IOU conversation with Energy Division on January 10th 2022, PG&E has removed Projected ongoing maintenance costs for utility-side infrastructure due to the IOUs not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs.

3. This includes an estimated $22,634 for Residential and $30,468 for Commercial Separate Meter Costs that are associated with TE Programs Infrastructure. These costs are included here because Separate Meter for EVCN and DC FC are captured under PG&E's GRC proceeding, not covered by these programs.

4. Includes costs for Mapping, Inspection, Land, Inspection, Project Management, and Administrative Overhead that are not included in other Site Costs subcategories.

5. Total Customer Costs do not reflect ITCC. Customer costs are subject to ITCC.

PG&E

Table 3: Program Costs

2021 EV-related Upgrade Costs[1,2]		Light Duty Vehicle Infrastructure			Program Commercial Charging Infrastructure Costs					
					Medium and Heavy Duty Vehicle Infrastructure[5]			Medium and Heavy Duty Vehicle Infrastructure		
					Utility-owned Customer-side Infrastructure			Customer-owned Customer-side Infrastructure		
		L2 Chargers - Multi-Unit Dwellings LDV	L2 Chargers - Workplaces LDV	DCFC - LDV[4]	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW
Site Costs ($)	Design costs[3]	$701,420	$1,245,107	$123,899	$0	$0	$0	$157,260	$11,886	$0
	Trenching and site excavation	$1,278,124	$4,423,499	$218,544	$0	$0	$0	$550,923	$29,100	$0
	Separate meter costs	$810,000	$945,000	$65,126	$0	$0	$0	$0	$0	$0
	Permitting costs	$221,501	$351,184	$14,427	$0	$0	$0	$141	$0	$0
	Total Utility side costs	$2,791,538	$3,834,054	$444,222	$0	$0	$0	$2,058,282	$201,312	$0
	Total Customer Side Costs	$8,295,670	$11,116,756	$944,491	$0	$0	$0	$0	$0	$0
Support Activities ($)	Project management	$395,738	$572,868	$190,633	$0	$0	$0	$202,064	$21,289	$0
	Customer outreach (labor)	$94,363		$393,575	$1,436,453					
	Outreach and education materials	$375,787		$0	$734,910					
	Other costs	$751,253		$100,000	$1,208,502					
Other	Total number of charge ports installed	832	953	16	0	0	0	105	6	0
	Amount of new capacity resulting from project (kW)	3,976	6,451	950	0	0	0	2,104	1,284	0

Notes:

1. Per Joint IOU conversation with Energy Division on January 10th 2022, PG&E has removed Total Distribution System Costs Incurred by Utility for Upgrades, Total Service Line costs Incurred by Utility for Upgrades from the Programs Cost table 3 as these categories are not applicable.
2. Per Joint IOU conversation with Energy Division on January 10th 2022, PG&E has removed Projected ongoing maintenance costs for utility-side infrastructure due to the IOUs not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs on a single structure/piece of equipment.
3. Design costs include only final design costs for 2021 fully invoiced projects
4 Any site that has a DCFC, even if L2 chargers are also installed, will be captured in the DCFC column
5 Medium and Heavy Duty infrastructure is categorized by site size based on amount of new capacity resulting from each project

PG&E

Table 4: Historic Costs Summary

	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019[2]	2020
Non-Program Residential Charging Infrastructure[1]									
Total Distribution System Costs Incurred by Utility for Upgrades	$282,719	$598,172	$1,476,647	$798,367	$404,236	$1,734,016	$927,375	$0	$1,181,289
Total Service Line Costs Incurred by Utility for Upgrades	$39,924	$69,380	$103,259	$41,377	$37,500	$27,706	$52,349	$10,137	$8,555
Total Customer Portion of Utility Costs Covered by the exemption	$9,226	$34,125	$76,046	$19,669	$3,856	$3,983	$29,618	$5,649	$41,247
Non-Program Commercial Charging Infrastructure									
Total Distribution System Costs Incurred by Utility for Upgrades								$757,669	$3,403,289
Total Service Line costs Incurred by Utility for Upgrades								$1,798,229	$2,726,958
Program Commercial Charging Infrastructure									
Total Utility Side Costs								$8,125,916	$11,146,234
Total Customer Side Costs								$19,699,909	$27,375,166

Notes:

[1] Historical upgrade costs are from data from previously submitted Load Research Reports. The data for the 2011 - 2012 report is from July 2011 through Oct 2012. The data for the next five reports and ending with the 2016-2017 report includes data from Nov - Oct of the following year. Data for the 2017-2018 report includes data from Nov 2017 through Dec 2018. The data for 2019 shows data for January-December of 2019.

[2] Details on the 2019 and 2020 historical costs can be found in the EV Infrastructure Cost Report that was filed on April 2, 2020 and March 31, 2021, respectively.

ATTACHMENT 2

VI. Attachment 2 - SCE

SCE

Table 1

Number of EVs forecasted In IOU Service Territory

		Light-Duty	Medium/ Heavy Duty
Actual	2011	1,736	
	2012	8,526	
	2013	21,896	
	2014	39,890	
	2015	58,908	
	2016	83,186	
	2017	114,738	
	2018	163,869	
	2019	210,620	
	2020	251,584	
	2021	329,940	
Forecasted	2022	398,801	1,895
	2023	500,847	3,495
	2024	628,491	5,974
	2025	741,619	9,412
	2026	875,111	13,787
	2027	1,061,315	18,977
	2028	1,252,352	24,798
	2029	1,477,775	30,684
	2030	1,743,775	40,419

Notes: Actual LDV values are provided by the Electric Power Research Institute ("EPRI") on annual light-duty vehicle sales, based on third party registration data.

-SCE's forecasts for light-duty, medium and heavy-duty electric vehicles reflect a forecast that more closely aligns with expected decarbonization funding, mandates, and support policies. Policies such as states 5 million zero-emission vehicles goals on the roads in California by 2030 for light duty and CARB's Innovative Clean Transit and Advanced Clean Trucks rules for medium/heavy duty and buses were considered.

SCE

Table 2: Non-Program Costs

2021 EV-related Upgrade Costs (Nominal Costs) [1,2,3]		Residential Charging Infrastructure	Non-pilot/program Commercial Charging Infrastructure
Site Costs ($)	Desgin Costs [4]	$686	$876,570
	Trenching and site excavation [5]	$0	$775,660
	Separate meter costs [6]	$197	$59,169
	Permitting costs [7]	$0	$24,621
	Total Distribution System Costs Incurred by Utility for Upgrades [8]	$0	$7,658,436
	Total Service Line costs Incurred by Utility for Upgrades	$11,121	$411,549
	Total Utility side costs [9]	$11,121	$8,069,985
	Total Customer costs [10, 11]	$0	$209,894
Other	Total number of charge ports installed	2	
	Amount of new capacity resulting from project (kW)	18	50,065

Key:	
	Data not available to report in 2021; SCE began tracking this information 1/1/2022, and will report 2022 tracked data on March 31, 2023

IOU Comments:
1. Per Joint IOU conversation wtih Energy Divsion on January 10, 2022, SCE has removed Projected ongoing maintenance costs for utility-side infrastructure from the Non-Programs Cost table 2 due to the IOUs not having a mechanism in place to seperate EV specific mainenance costs from general rate maintenance costs on a single structure/piece of equipment.
2. Per Joint IOU conversaton with Energy Division on January 10, 2022, SCE has removed Project managment, Customer outreach (labor), Marketing and education materials, and Other costs from the Non-Programs Cost table 2 as these categories are not applicable.
3. Please reference IV. Cost Tracking Data C. SCE's EV Infrastructure Cost Data Table 2 in Attachment 2: Non-Program Costs to find relevant explanations for this table.
4. Design Costs include estimated Utility-side costs only, and are included in the appropriate distribution system or service line cost total.
5. Estimated trenching and excavation costs, if performed by the utility, for all utility-side work related to excavation and installation of underground ducts and structures required for projects, and are included in the appropriate distribution system or service line cost total.
6. To better estimate meter costs, SCE is providing site level estimated meter costs provided by our design system. These costs are included in the appropriate distribution system or service line cost total.
7. Estimated permit costs are included in the appropriate distribution system or service line cost total.
8. Total Distribution System Costs incurred by the Utility for upgrades; If both distribution (Rule 15) and service costs (Rule 16) are included in a single work order, the service costs are included in the distribution system costs total.
9. Total Utility-side costs - The number provided, a combination of both actual and estimated dollars, represents the total utility-side (to the meter) expenditure for all capital direct costs and indirect labor overheads recorded costs, up to but not including the meter pedestal or meter panel for completed projects within the reporting period. Cost categories include, for example, trenching, permitting, estimated meter costs, and other material (including transformation) as well as division overhead.
- Includes division overhead costs (e.g. planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g. pension, benefits, etc.).
10. Total Customer Costs for Residential Customers is the amount of excess cost to serve that would have been billable to the customer if the current residential allowance exemption was not in place, as well as, if applicable, riser, permit, right's check, and/or easement document fee's.
11. Total Customer Costs for Commercial Customers is the amount invoiced by SCE and paid by the Customer.

SCE

Table 3: Program Costs

2021 EV-related Upgrade Costs (Nominal Costs)[1,2,3]		Pilot and Program Commercial Charging Infrastructure										
		Light Duty Vehicle Infrastructure					Medium and Heavy Duty Vehicle Infrastructure			Medium and Heavy Duty Vehicle Infrastructure		
			L2 Chargers - Non-Residential LDV				Utility-owned Customer-side Infrastructure			Customer-owned Customer-side Infrastructure[11]		
		L2 Chargers - Multi-Unit Dwellings	L2 Chargers - Workplace	L2 Chargers - Destination Center	L2 Chargers - Fleet	DCFC - LDV	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW
Site Costs ($)[4]	Design costs[5]	$393,374	$345,329	$224,020	$26,457	$0	$147,767	$0	$0	$0	$0	$0
	Trenching and site excavation[6]	$2,004,705	$3,978,030	$2,258,677	$119,892	$0	$1,483,729	$0	$0	$0	$0	$0
	Separate meter costs[7]	$5,838	$6,350	$3,035	$131	$0	$8,839	$0	$0	$0	$0	$0
	Permitting costs[6]	$19,652	$47,455	$9,776	$831	$0	$9,016	$0	$0	$0	$0	$0
	Total Utility side costs[8]	$630,747	$1,026,283	$702,700	$12,905	$0	$957,847	$0	$0	$0	$0	$0
	Total Customer-side costs[9]	$2,373,520	$4,295,538	$2,433,349	$146,103	$0	$1,557,241	$0	$0	$0	$0	$0
Support Activities ($)	Project management	$1,411,329				$0	$557,306	$0	$0	$0	$0	$0
	Customer outreach (labor)	$594,220				$0	$216,435	$0	$0	$0	$0	$0
	Marketing and education materials	$2,715,456				$0	$285,899	$0	$0	$0	$0	$0
	Other costs[10]	$2,839,627				$0	$73,404	$0	$0	$0	$0	$0
Other	Total number of charge ports installed	178	373	253	10	-	88	-	-	-	-	-
	Amount of new capacity resulting from project (kW)	122.4	64.8	28.8	7.2	-	620	-	-	-	-	-

Notes:

1. Per Joint IOU conversation with Energy Division on January 10th 2022, SCE has removed Total Distribution System Costs Incurred by Utility for Upgrades, Total Service Line costs Incurred by Utility for Upgrades from the Programs Cost table 3 as these categories are not applicable.
2. Per Joint IOU conversation with Energy Division on January 10th 2022, SCE has removed Projected ongoing maintenance costs for utility-side infrastructure due to the IOUs not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs on a single structure/piece of equipment.
3. Please reference IV. Cost Tracking Data C. SCE's EV Infrastructure Cost Data Table 3 in Attachment 2: Pilot-Program Costs to find relevant explanations for this table.
4. Site Costs ($) - Capital costs reported for completed projects in 2021. SCE is aware there are trailing costs in 2022.
5. Design costs include estimated Utility-side costs and actual Customer-side costs.
6. Only Customer-side costs separated into Trenching and site excavation and Permitting costs.
7. To better estimate meters, SCE is providing site level estimated meter costs from our design system.
8. Total Utility-side costs - The number provided, a combination of both actual and estimated dollars, represents the total utility-side (to the meter) expenditure for all capital direct costs and indirect labor overheads recorded costs, up to but not including the meter pedestal or meter panel for completed projects within the reporting period, separated by respective programs. Cost categories include, for example, trenching, permitting, estimated meter costs, and other material (including transformation) as well as division overhead.
- Includes division overhead costs (e.g. planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g. pension, benefits, etc.).
- Transformers sized at or less than 500 kVA are estimated costs. Transformers sized greater than 500 kVA are specialty items that SCE orders and charges directly to the work orders.
9. Total Customer side costs provide a combination of both actual and estimated dollars, represents the total customer-side (behind or beyond the meter) expenditure for all capital direct and indirect labor overheads recorded costs, from the meter pedestal or meter panel, up to but not including the EVSEs for completed projects. Examples of included costs are design, trenching, permitting, labor and material such as the meter pedestal or meter panel, transformation, cable, and connectors.
- Includes division overhead costs (e.g. Planner activities such as site visits, creating the design and operations activities such as scheduling work, staging material, etc.) and Capital overhead labor loaders (indirect) costs (e.g. pension, benefits, etc.).
10. Other costs include rebates, canceled project costs, Capital IT implementation costs, and estimated O&M labor indirect costs. SCE can only provide estimated O&M labor indirect costs because SCE corporate overhead loaders are authorized in SCE's GRC and are separately recorded in the Pension, Medical, and PBOB Balancing Accounts. O&M pension & benefits do not follow the program accounting.
11. SCE does not have any Customer-owned Customer-side Infrastructure projects completed in 2021.

SCE

Table 4: Historic Costs Summary

	Non-Pilot/program Residential Charging Infrastructure	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019	2020
Historical Upgrade Costs (Nominal Costs) [1,2,3]	Total Distribution System Costs Incurred by Utility for Upgrades	$4,268	$4,863	$9,373	$17,290	$2,984	$0	$1,845	$39,369	$0
	Total Service Line costs Incurred by Utility for Upgrades	$26,433	$43,586	$67,627	$76,000	$44,561	$17,152	$37,538	$54,136	$24,969
	Total Customer Portion of Utility Costs Covered by the exemption	$6,133	$12,704	$4,246	$4,885	$1,174	$375	$8,120	$511	$0
	Non-Pilot/Program Commercial Charging Infrastructure									
	Total Distribution System Costs Incurred by Utility for Upgrades								$2,814,530	$6,582,132
	Total Service Line costs Incurred by Utility for Upgrades								$358,083	$660,520
	Pilot/Program Commercial Charging Infrastructure									
	Total Utility Side Costs								$4,286,852	$5,676,706
	Total Customer-Side Costs								$4,955,447	$14,191,453

Notes:

1. The 2011-2012 reporting period is from July 2011 to October 2012. The reporting period for the next five reports, ending with the 2016-2017 report is from November through October of the following year. The reporting period for the 2017-2018 report is November 2017 through December 2018. Beginning 2019, the reporting period is from January to December.
2. For 2020, while meter costs occured in both Non-Pilot/Program Commercial Charging Distribution System costs and Service Line costs, the total meter costs of $22,352 are shown in the Total Service Line cost total only.
3. The figures shown in Pilot/Program Commercial Charging Infrastructure in 2020, are inception to date recorded costs for projects completed in 2020. This method is an update to prior year as the costs shown in 2019 are year to date recorded costs for all Pilot/Program Capital spend.

ATTACHMENT 3

VII. Attachment 3 – SDG&E

SDG&E

Table 1: Number of EVs forecasted in the IOU Service Territory

Number of EVs forecasted in IOU Service Territory			
		Light-Duty	Medium/Heavy Duty
Actual:	2011	-	
	2012	2,125	
	2013	4,400	
	2014	11,500	
	2015	18,000	
	2016	22,040	
	2017	26,498	
	2018	34,833	
	2019	49,585	
	2020	56,274	
	2021	73,283	
Forecasted:	2022	84,076	1,341
	2023	96,387	1,846
	2024	108,698	2,643
	2025	121,008	3,683
	2026	133,319	4,947
	2027	145,630	6,444
	2028	157,940	8,242
	2029	170,251	10,463
	2030	182,562	13,084

IOU Comments:

Light-Duty historical/actual counts: Historical EV counts are based off the EV count communicated in the load research report for that year.

Light-Duty forecasted counts: SDG&E's EV forecast represents the expected growth in the SDG&E service territory without the influence of SDG&E's EV programs at each year end.

Medium/Heavy-Duty forecasted counts: There is a general uncertainty about the number of medium-duty / heavy-duty (MD/HD) vehicles operating in California. SDG&E’s medium and heavy-duty forecast derives from policy-driven EV modeling that integrates meeting the state’s decarbonization mandates and policies (e.g., Executive Order N-79-20 goals). SDG&E’s EV adoption forecast for the MD/HD sector is subject to market demand variability, technology development, and new information development and insights. Therefore, this forecast is subject to uncertainty and adjustments.

SDG&E

Table 2: EV Related Upgrade Costs – Non-Program Costs

2021 EV-related Upgrade Costs		Residential Charging Infrastructure	Non-pilot/program Commercial Charging Infrastructure
Site Costs ($)	Design costs	$58,582	$176,114
	Trenching and site excavation	$49,115	$159,115
	Separate meter costs	$9,341	$44,114
	Permitting costs	$0	$0
	Total Distribution System Costs Incurred by Utility for Upgrades	$14,195	$454,792
	Total Service Line costs Incurred by Utility for Upgrades	$133,151	$22,553
	Total Utility side costs	$537,053	$733,156
	Total Customer costs	$4,608	$133,085
Other	Total number of charge ports installed		
	Amount of new capacity resulting from project (kW)		

Key:	
(shaded)	Data not available to report for 2022, but utilities have begun tracking for future reports

Notes:
1. Per joint IOU conversation with Energy Division on January 10th, 2022, SDG&E has removed Project management, Customer outreach (labor), Marketing and education materials, and Other costs from the Non-Programs Cost table 2 as these categories are not applicable.
2. Per joint IOU conversation with Energy Division on January 10th, 2022, SDG&E has removed Projected ongoing maintenance costs for utility-side infrastructure due to the joint IOUs not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs on a single structure/piece of equipment.

SDG&E

Table 3: EV Related Upgrade Costs – Pilot and Program Costs

2021 EV-related Upgrade Costs		Pilot and Program Commercial Charging Infrastructure										
		Light Duty Vehicle Infrastructure					Medium and Heavy Duty Vehicle Infrastructure			Medium and Heavy Duty Vehicle Infrastructure		
							Utility-owned Customer-side Infrastructure			Customer-owned Customer-side Infrastructure		
		L2 Chargers - Multi-Unit Dwellings	L2 Chargers - Workplace	L2 Chargers - Destination Center	L2 Chargers - Fleet	DCFC - LDV [1]	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW
Site Costs ($)	Design costs	-	-	-	-	-	21,923	-	-	8,108	-	-
	Trenching and site excavation	-	-	-	-	-	39,237	-	-	14,512	-	-
	Separate meter costs	-	-	-	-	-	1,522	-	-	563	-	-
	Permitting costs	-	-	-	-	-	963	-	-	356	-	-
	Total Utility side costs	-	-	-	-	-	82,591	-	-	30,547	-	-
Support Activities ($)	Project management	-	-	-	-	146,779	412,960	-	-	-	-	-
	Customer outreach (labor)	-	-	-	-	-	66,523	-	-	-	-	-
	Marketing and education materials	-	-	-	-	61,726	400,631	-	-	-	-	-
	Other Costs	-	-	-	-	-	-	-	-	-	-	-
Other	Total number of charge ports installed	-	-	-	-	-	-	-	-	-	-	-
	Amount of new capacity resulting from project (kW)	-	-	-	-	-	-	-	-	-	-	-

Notes:
1. DCFC-LDV includes any site that has a DCFC installed, even if L2 chargers are also installed
2. Per joint IOU conversation with Energy Division on January 10th, 2022, SDG&E has removed Total Distribution System Costs Incurred by Utility for Upgrades, Total Service Line Costs Incurred by Utility for Upgrades from the Programs Cost table 3 as these categories are not applicable.
3. Per joint IOU conversation with Energy Division on January 10th, 2022, SDG&E has removed Projected ongoing maintenance costs for utility-side infrastructure due to the joint IOUs not having a mechanism in place to separate EV specific maintenance costs from general rate maintenance costs on a single structure/piece of equipment.

SDG&E

Table 4: Historical Upgrade Costs

	Non-Pilot/program Residential Charging Infrastructure	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019	2020
Historical Upgrade Costs	Total Distribution System Costs Incurred by Utility for Upgrades	$4,089	$0	$0	$0	$0	$0	$124,572	$42,438
	Total Service Line costs Incurred by Utility for Upgrades	$27,952	$0	$1,876	$2,326	$2,009	$15,113	$23,535	$44,954
	Total Customer Portion of Utility Costs Covered by the exemption	$32,041	$0	$1,876	$2,326	$2,009	$15,113	$2,046	$3,563
	Non-Pilot/Program Commercial Charging Infrastructure								
	Total Distribution System Costs Incurred by Utility for Upgrades								$58,066
	Total Service Line costs Incurred by Utility for Upgrades								$5,547
	Pilot/Program Commercial Charging Infrastructure								
	Total Utility Side Costs								$403,332
	Total Customer Side Costs								$0

Notes:
1. Historical upgrade cost from previously submitted Load Research Reports periods 2012-2018
2. 2019 Historical upgrade costs based on actual cost incurred for customer upgrade jobs completed in 2019
3. 2020 Historical upgrade costs based on amended submittal December 13, 2021