SELF-GENERATION INCENTIVE PROGRAM

2021-2022 SGIP IMPACT EVALUATION

Submitted to:
Pacific Gas and Electric Company
SGIP Working Group

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1 EXECUTIVE SUMMARY

The Self-Generation Incentive Program (SGIP) was established in 2001 and provides financial incentives for the installation of behind-the-meter (BTM) distributed generation and energy storage technologies that meet all or a portion of a customer's electricity needs. The SGIP is funded by California's ratepayers and managed by Program Administrators (PAs) representing California's major investor-owned utilities (IOUs). The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP.

The SGIP was initially designed to provide incentives for distributed generation technologies to help address peak electricity problems in California. The program has been revised and extended multiple times since 2001, with eligibility requirements, program administration and incentive levels all changing over time. Technological advancements, policy interventions and ratepayer funding have contributed to where the SGIP is today. In 2020, the CPUC issued Decision (D.) 20-01-021, which authorized the collection of ratepayer funds totaling $166 million per year from 2020 to 2024 across the four program administrators. This decision increased the financial incentive budget for energy storage technologies to 88% of total SGIP funding. The remainder of the budget was carved out for other storage customer sectors, heat pump hot water heaters (HPWH), and renewable generation technologies.

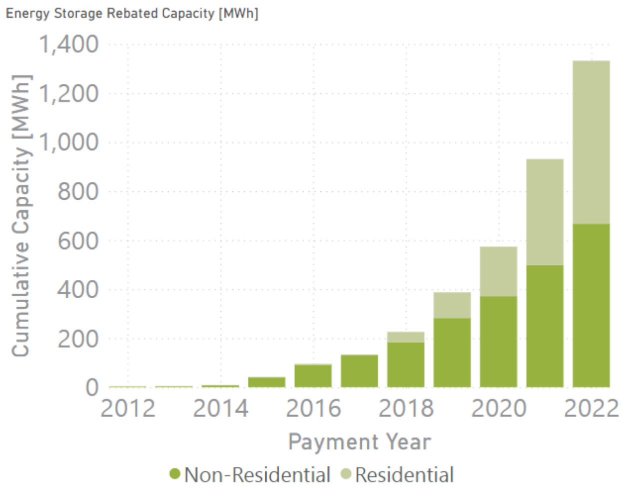
Measurement and Evaluation

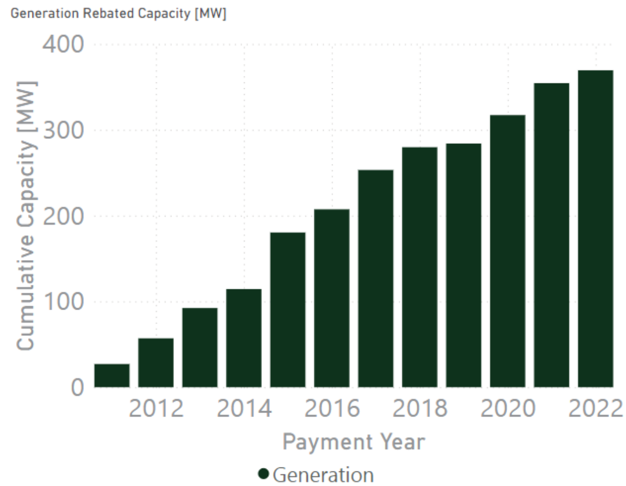
SGIP eligibility requirements and incentive levels have changed over time in alignment with California's evolving energy landscape. Ongoing evaluation reports serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet its goals. CPUC D. 19-09-027 required the SGIP program administrators to develop an M&E Plan for 2021-2025, which was approved in May of 2022, and finalized in January of 2023**. The primary objective of this study is to satisfy the requirements of the 2021-2025 M&E Plan by evaluating the performance of incentivized SGIP systems operating during calendar years 2021 and 2022.**

Evaluation Population

The SGIP population subject to evaluation encompasses all projects (cumulative) receiving an upfront SGIP incentive through December 31, 2022, and remaining within their required permanency period as specified by the program handbook. The evaluation population includes **37,282 SGIP projects** representing roughly **1,332 MWh of energy storage equipment rebated capacity and 369 MW of generation equipment rebated capacity**. Cumulative rebated capacities (MW for generation projects and MWh for energy storage projects) are summarized by equipment type and payment year in Figure 1-1. Most energy storage projects were electrochemical battery systems. Electric-only fuel cell projects accounted for a third of the total rebated generation capacity.

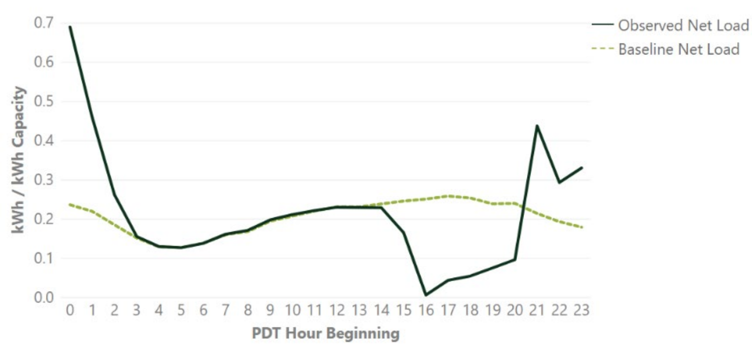
FIGURE 1-1: CUMULATIVE REBATED CAPACITY BY EQUIPMENT TYPE AND PAYMENT YEAR



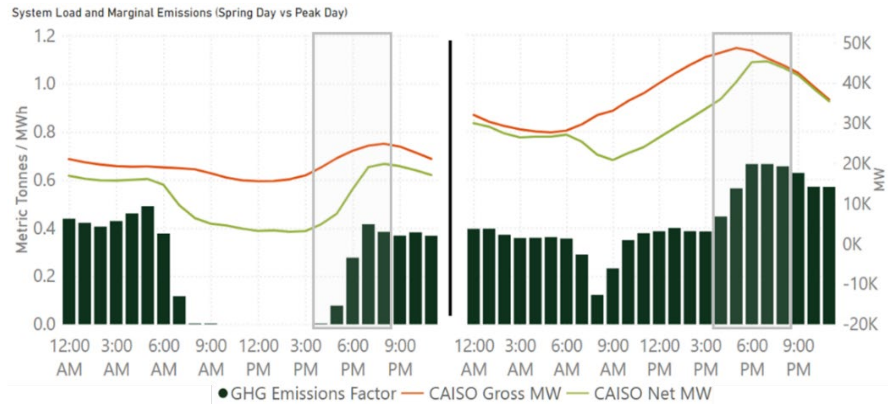


Evaluation Approach

This evaluation examines the performance of SGIP systems by quantifying the observed impacts of systems during 2021 and 2022. Verdant collected metered generation data, storage charge and discharge data, and customer electric load profiles for SGIP participants. Some of the results discussed in this report are developed to better understand the efficiency of SGIP systems or how well utilized they are throughout the year. Some impacts, such as change in coincident peak electricity demand measured at the utility meter, require additional assumptions about what a customer's electricity consumption at the meter would have been had they *not* installed the SGIP system. These assumptions describe an unobservable counterfactual non-SGIP baseline that is compared to observed electricity consumption to estimate impacts of the SGIP system at the utility meter. The calculation of energy storage impacts, for example, is illustrated in the inset figure depicting average hourly delivered load on summer weekdays. If a customer is discharging their battery, they are reducing the need to service load from the grid so observed net load is lower than baseline net load. When a customer is charging the battery, they are increasing their load relative to a baseline of no storage. A customer could realize bill savings relative to the counterfactual if discharging occurred during high-priced hours and charging occurred during lower-priced hours. Furthermore, systems could provide greenhouse gas (GHG) reductions if the emissions *avoided* during storage discharge are greater than the emission *increases* during storage charging.



The relationship between grid load and marginal GHG emissions is depicted graphically below. System load and corresponding marginal emissions on the left are typical of a spring day. For many hours of the day where marginal emissions are zero, ample sunshine, long daylight hours, and low demand for energy-intensive end uses like HVAC allow grid-scale renewable solar generation to provide nearly all load to satisfy system demand. During the 4pm and 5pm hours, renewable generation (represented by the difference between CAISO Gross and Net Load) decreases from its mid-day maximum and is displaced by more carbon-intensive generators. System load on the peak day (right pane) is much greater and marginal emissions don't hit zero at any point throughout the day. At the net peak (6pm – 8pm) emissions remain constant where the most carbon-intensive generator is operating at the margin.



Evaluation Findings, Conclusions and Recommendations

Below we present key findings and conclusions from this evaluation based on metered data collected from a representative sample of residential and nonresidential customers (detailed in Section 5). Where possible, we also provide recommendations that could inform future policy and program design. Many of these findings reveal how storage behavior throughout 2021 and 2022 was meeting or falling short of SGIP goals and objectives. In-depth findings and analyses can be found in Section 6 of this report.

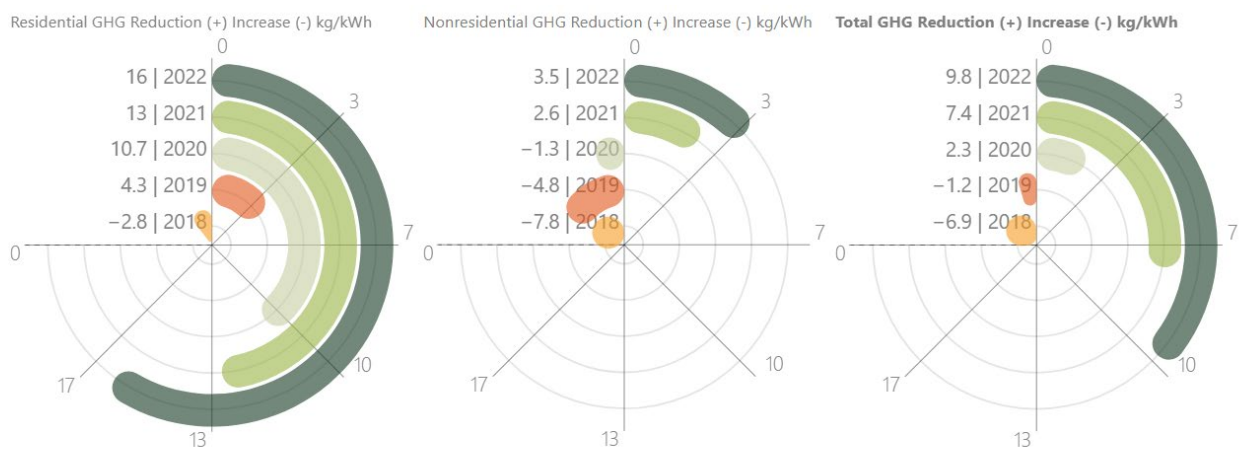
Storage Dispatch Behavior

Solar PV-paired residential energy storage systems are generally conducting 1) TOU arbitrage without export, 2) TOU arbitrage with export – either regularly or exclusively during specific times like a demand response event, 3) self-consumption, or 4) some combination of the above (Section 6.2.1). We also observe under-utilization – not at a fleet or sector level, but from project to project. Idle, under-utilized systems are likely servicing a load much less than the capacity of the system or are prioritizing back-up (which is contrary to SGIP's purpose). We also observe **some systems paired with PV that were charging from solar in 2021, but begin charging the battery overnight in 2022, perhaps to take advantage of relatively lower off-peak electric vehicle (EV) billed rates.** This latter behavior is far more infrequent, but the impacts resemble those of standalone systems – the change in timing of storage charging results in GHG emissions increases.

Greenhouse Gas Emissions

Residential *and* nonresidential energy storage systems, alone and combined, contributed to a net reduction in GHG emissions in 2021 and 2022. The combined GHG reductions totaled 6,930 metric tons (MT) in 2021 and improved to over 13,000 in 2022 (Section 6.4.1 and 6.8). This follows a trend first observed in 2020 in the residential sector and at the program level, despite emissions increases from the nonresidential sector in that year. Figure 1-2 plots the decrease (+), moving clockwise from zero, or increase (-), moving counterclockwise, in emissions for each customer sector – along with the total program impact – from the past five evaluations (2018-2022). Residential fleet reductions were first observed in 2019 and have increased substantially with each successive evaluation – from an average reduction of 4.3 kilograms (kg) for each kWh of capacity in 2019 to a reduction of 16 kg for each kWh of capacity in 2022. The improvement in GHG emissions from nonresidential fleet performance suggests that the sector has turned a corner since earlier evaluation years – with emissions reductions of 2.6 and 3.5 kg for each kWh of capacity in 2021 and 2022, respectively. An increasing share of PV paired systems charging from on-site solar and more focused on-peak discharging from more recently incentivized systems have contributed to that improvement.

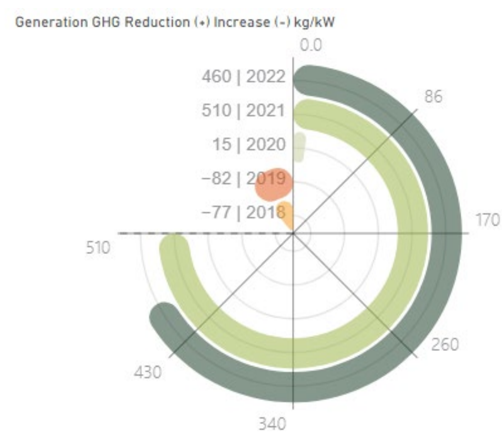
FIGURE 1-2: STORAGE GHG EMISSIONS IMPACTS BY YEAR AND SECTOR (KG/KWH, REDUCTION (+) INCREASE (-))



Residential storage systems paired with on-site PV *and* charging from PV *decreased* emissions by over 17 kg per kWh of capacity, while standalone systems and PV-paired systems charging overnight increased emissions by almost 4 kg per kWh of capacity (Section 6.4.1). While standalone or paired systems may exhibit the same discharge behavior – to satisfy an energy arbitrage opportunity or for self-consumption – solar pairing plays an essential role in dictating when a system charges. Systems paired with on-site solar and charging from that solar provide benefits not realized by systems charging overnight. **From a GHG perspective, the value of charging during PV generating hours cannot be overstated.** SGIP energy storage systems are discharged in late afternoon and early evening when retail electricity rates are higher and on-site generation and grid-level renewable generation wanes – times that coincide with high marginal emission periods and billed on-peak hours. ***The emissions differentials between charging overnight and discharging on-peak are not sufficient to realize emissions reductions like observed with PV paired systems charging from on-site PV during much lower emissions hours. We recommend that the CPUC explore ways to ensure that standalone systems achieve GHG reductions, such as requiring that they follow the SGIP GHG signal or real-time pricing signals.***

Nonresidential systems paired with PV reduced emissions in 2022 by roughly 10 kg per kWh of capacity (Section 6.4.1). Average reductions for PV paired systems range from almost 4 kg per kWh of capacity for systems paid in 2017 and prior to as high as 22 kg per kWh for systems paid more recently. Emissions reductions for PV paired systems were realized across all facility types. **Standalone nonresidential systems increased emissions in 2022 by 1 kg per kWh of capacity.** However, for systems paid in 2021 and 2022, we observe a shift from average emissions increases to reductions. More recent installations of longer duration batteries installed through the Equity Resiliency Budget (ERB) are conducting arbitrage and reducing emissions at the expense of the non-coincident peak demand reductions – and subsequent charging "snapback" associated with demand shaving.

Generation systems provide the vast majority of GHG emissions reductions in 2021 and 2022 (Section 6.4.2). Although generation systems comprise roughly 1.5% of the systems installed in the SGIP, they reduced emissions by 460 kg per kW of rebated capacity throughout 2022. Renewable fueled systems capturing methane that would otherwise be vented into the atmosphere contributed to the greatest avoided GHG impact, followed by renewably fueled systems with a flared baseline and non-fueled systems. Non-renewable Gas Turbines also reduced emissions, due to their high rates of heat recovery. **These reductions are highly dependent on marginal emissions rates built into the SGIP GHG signal.** While the SGIP generation population has changed over the last five years, much of the variation in the figure to the right stems from changes made to assumptions in the calculation of GHG signal values. The changes (which increased the GHG signal values in most hours) were required to maintain consistency between GHG signal values and assumptions in the current version of the Avoided Cost Calculator approved by the CPUC.



System Utilization and Grid Needs

As a load shifting technology, BTM storage can provide grid benefits if the timing and magnitude of storage discharge aligns with periods of grid stress and coincident peak demand while system charging is left to less critical times. The timing and magnitude of storage charge and discharge is influenced by several factors: 1) underlying customer load shapes, 2) storage system mode of operation, 3) customer rate schedule, 4) on-site solar PV presence, and 5) storage system sizing (kW and kWh) relative to customer load. Utility marginal costs and grid constraints are generally highest during on-peak hours, which are captured with TOU on-peak periods in California (generally 4pm – 9pm). Conversely, storage charging is best left to off-peak and super off-peak time periods when retail rates are lower, as are utility avoided costs, marginal emissions, and grid constraints. Renewably fueled and non-fueled generation technologies provide consistent, low emission generation throughout the year, and have provided additional capacity during times of grid constraints. California witnessed significant energy constraints during 2020, and in response, one fuel cell manufacturer, which has incentivized most of the all-electric fuel cell capacity in the SGIP, ran an initiative to export significant energy to help relieve the strain on the grid using combustion-free, fuel flexible technologies.

Residential and nonresidential systems are not discharging the total capacity of the system regularly and many residential customers are limiting discharge to maintain net zero load rather than exporting (Section 6.2.1). This finding is intuitive – if customers are already abiding by SGIP rules for round trip efficiency, utilization and GHG reductions – they may also want to have reserve energy in the event of an outage. Furthermore, frequent full discharge cycling may not be advantageous from a battery engineering, effective useful life, and warranty perspective. However, there is considerable untapped potential for Resource Adequacy (RA), Emergency Load Reduction Program (ELRP), and other grid benefits if additional battery capacity is deployed in response to grid needs and/or price signals. ***We recommend that the CPUC explore ways to encourage additional battery utilization through enrollment in virtual power plants (VPP), utility control of storage, participation in real-time rates, or other mechanisms. We also recommend battery developers collect and provide state-of-charge (SOC) information in addition to charge/discharge data so that future evaluations can study the relationship between maximum and minimum SOC settings and SGIP benefits.***

Solar PV paired residential storage discharges roughly 45% of system kWh capacity daily throughout summer weekdays, and standalone systems discharge about 22% of available capacity (Section 6.2.1). Most of that discharge occurs during the 4pm – 9pm on-peak hours (60% for PV paired systems and 72% for standalone systems). On-peak hours, when retail energy rates are highest, provide the greatest opportunity for customers to realize billed energy savings. If a residential customer is discharging any percentage of energy outside this period, this suggests that bill reductions may not be the primary driver or system operating mode. In fact, we observe self-consumption as a popular operating mode for residential storage at a fleet level. Self-consumption involves limiting utility delivered load by discharging the battery to service plug loads, refrigerators, Wi-Fi, television, etc. even outside of on-peak hours. Since systems in self-consumption mode are limited by underlying customer load, hourly discharge ranges from 1% to 7% of system kwh capacity depending on the month (Figure 1-3). ***We recommend that the CPUC explore ways to encourage more targeted dispatch that emphasizes the importance of discharging batteries (and reducing load) during on-peak hours rather than daily self-consumption.***

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FIGURE 1-3: RESIDENTIAL STORAGE DISCHARGE AND CHARGE KWH PER KWH CAPACITY

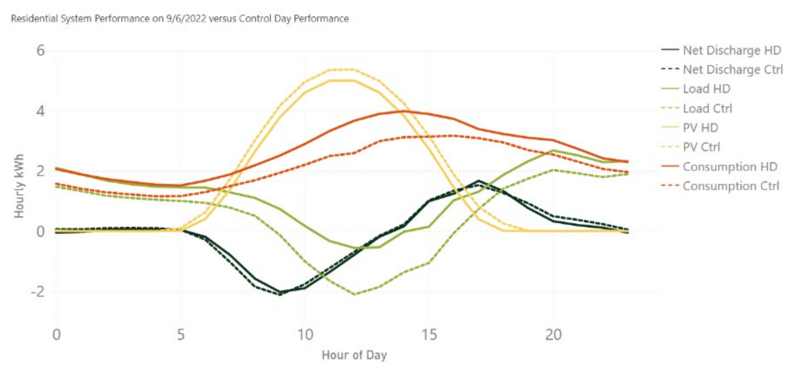
PV Paired	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	1%	0%	0%	0%	0%	0%	0%	-0%	-2%	-5%	-6%	-6%	-5%	-3%	-1%	0%	3%	4%	5%	4%	3%	1%	1%	1%
February	1%	1%	0%	0%	0%	0%	1%	-1%	-4%	-7%	-8%	-7%	-5%	-3%	-1%	0%	2%	4%	5%	5%	4%	2%	2%	1%
March	1%	1%	1%	1%	1%	1%	1%	-0%	-4%	-7%	-9%	-8%	-6%	-4%	-1%	-0%	2%	4%	5%	5%	4%	3%	2%	2%
April	2%	1%	1%	1%	1%	1%	1%	-1%	-4%	-8%	-10%	-8%	-5%	-3%	-1%	0%	2%	3%	5%	5%	4%	3%	3%	2%
May	2%	1%	1%	1%	1%	1%	1%	-1%	-5%	-9%	-10%	-8%	-5%	-3%	-1%	0%	2%	3%	5%	5%	5%	3%	3%	2%
June	1%	1%	1%	1%	1%	1%	0%	-2%	-6%	-10%	-10%	-8%	-5%	-3%	-1%	1%	3%	5%	6%	6%	5%	3%	3%	2%
July	1%	1%	1%	1%	1%	1%	0%	-1%	-5%	-9%	-10%	-9%	-6%	-3%	-1%	0%	3%	5%	6%	6%	5%	3%	2%	2%
August	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-8%	-11%	-9%	-7%	-4%	-1%	1%	4%	6%	7%	6%	5%	3%	2%	1%
September	1%	0%	0%	0%	1%	1%	1%	-0%	-3%	-7%	-10%	-9%	-7%	-4%	-1%	0%	4%	5%	7%	6%	4%	2%	2%	1%
October	1%	1%	1%	1%	1%	1%	1%	0%	-2%	-6%	-9%	-9%	-7%	-5%	-2%	-0%	3%	5%	6%	5%	4%	2%	2%	1%
November	0%	0%	0%	0%	0%	0%	0%	-1%	-4%	-6%	-8%	-7%	-5%	-3%	-1%	1%	4%	5%	5%	4%	3%	2%	1%	1%
December	-0%	-0%	-0%	0%	0%	0%	0%	-0%	-2%	-5%	-6%	-6%	-5%	-3%	-1%	1%	4%	5%	5%	3%	2%	1%	1%	0%
No PV	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
January	-3%	-2%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	1%	1%	2%	2%	1%	-1%	-1%	-1%
February	-4%	-2%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	1%	1%	2%	2%	1%	-1%	-1%	-1%
March	-5%	-2%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	1%	1%	1%	2%	2%	-1%	-0%	-2%
April	-5%	-2%	-1%	-0%	-0%	-0%	-0%	-0%	0%	0%	-0%	-0%	-0%	-0%	0%	1%	2%	2%	2%	2%	1%	-1%	-0%	-2%
May	-6%	-3%	-1%	-0%	-0%	-0%	0%	-0%	0%	0%	-0%	-0%	-0%	-0%	0%	1%	2%	2%	2%	2%	2%	-1%	-0%	-1%
June	-7%	-4%	-2%	-0%	-0%	-0%	-0%	0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	2%	3%	3%	2%	2%	2%	-1%	-1%	-1%
July	-7%	-5%	-2%	-0%	-0%	-0%	0%	0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	3%	3%	3%	2%	2%	-1%	-1%	-1%
August	-9%	-6%	-3%	-0%	-0%	-0%	-0%	0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	4%	4%	4%	3%	3%	-0%	-1%	-1%
September	-10%	-6%	-3%	-0%	-0%	-0%	0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	4%	4%	4%	3%	3%	-0%	-0%	-1%
October	-10%	-5%	-2%	-0%	-0%	-0%	-0%	0%	-0%	-0%	-0%	-0%	-0%	0%	0%	1%	3%	3%	3%	3%	2%	-0%	0%	-1%
November	-10%	-6%	-3%	-0%	-0%	-0%	0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	0%	1%	3%	3%	3%	3%	3%	0%	0%	-1%
December	-11%	-8%	-4%	-0%	-0%	-0%	0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	0%	1%	4%	4%	4%	4%	3%	-0%	0%	-1%

Residential and nonresidential storage systems are providing grid relief throughout CAISO peak hours, however there is significant untapped potential to provide grid benefits (Section 6.3.1). Utility planners are concerned about two peak periods; 1) the gross peak – when overall demand is at its highest and all available electricity supply sources reach their maximum generation and 2) the net peak – when overall demand minus renewable supply sources is reaching peak generation. The total program energy capacity in 2022 was over 1,300 MWh. Residential and nonresidential systems discharged roughly 56 MWh (about 4% of total program energy capacity) during the top gross peak hour, and 90 MWh (~7%) during the top net peak hour (which is when the greatest grid stress occurs, and when energy prices are the highest).

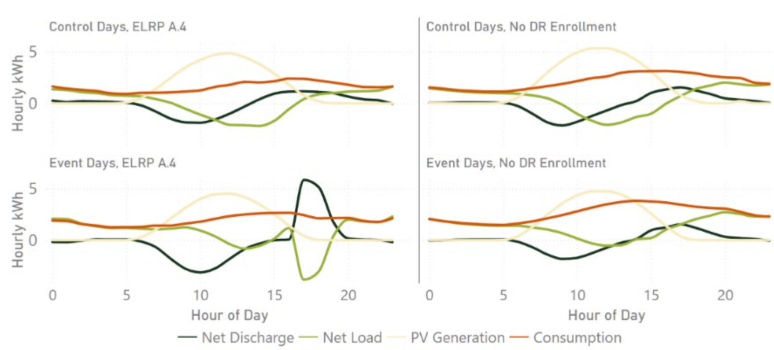
The magnitude of impacts during top hours continues to evolve from one evaluation to the next (Section 6.3.1). This is due, in part, to peak CAISO hours differing from year to year as well as the underlying load shapes and use cases of customers in SGIP changing from one year to the next. Two of the more critical recent changes are 1) more nonresidential discharging during on-peak hours – particularly with PV paired systems and medium duration batteries installed via the Equity Resiliency Budget (ERB) category, and 2) residential systems discharging a greater percentage of capacity during the latter half of the on-peak period. Energy storage export, increased price differentials between billed on and off-peak, demand response participation like ELRP, and developer fleet dispatch modifications have contributed to more significant grid benefits.

Beneficial SGIP energy storage performance was observed throughout the first full week in September 2022 when protracted high temperatures throughout California created life-threatening conditions for millions and created extreme demands on the CAISO and utility systems (Section 6.3.1). However, the operating modes producing that beneficial performance throughout critical hours – self-consumption, arbitrage, arbitrage with export, peak/partial-peak demand charge reduction – were also observed outside these constrained hours during 2022. PV paired systems were generally charging during lower grid constrained hours and both PV paired and standalone systems were discharging in the early afternoon and evening during high utility cost hours and system peaks, particularly throughout summer months. **In other words, SGIP energy storage systems were not performing too differently during capacity constrained hours than they were ordinarily in 2022.**

The figure below highlights this. Average hourly PV generation, delivered/received load, BTM consumption and storage charge (-) and discharge (+) are plotted for those September days (solid lines) and compared against similar (control) days in 2022 not during that week (dashed lines). We observe an increase in household consumption (red lines) and delivered load (green lines) throughout those September days, **but there is no discernible difference in storage system utilization** (black lines). Storage systems are generally following a price signal built into a customer billed on- and off-peak rate schedule, so behavioral changes from event days to control days would be either wholly coincidental or predicated on additional signals to customers – flex alert notifications and/or demand response participation where, in the case of ELRP, load reductions can be compensated at up to $2.00 per kWh.



In fact, ELRP participation is where we observe differences in storage dispatch between event and control days (Section 6.3.1). During event days, which in 2022 align with those capacity constrained grid hours, systems that were ordinarily arbitraging or self-consuming – but were enrolled in ELRP – were discharging to almost full capacity during events. The roughly six kWh magnitude of average discharge throughout each of the first two hours of the ELRP events on 9/5 - 9/8 is evident in the inset figure. Not

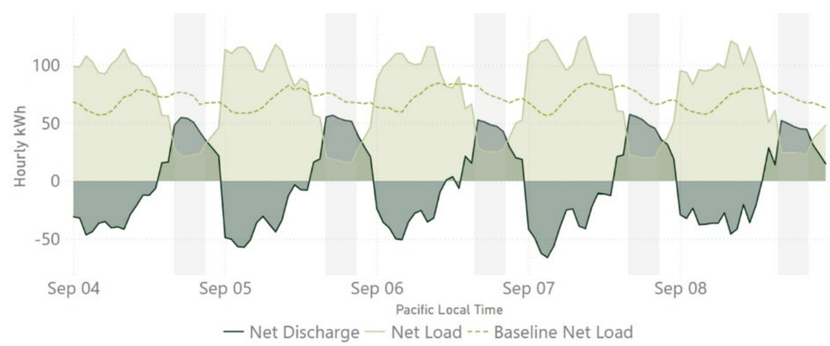


only were ELRP participants discharging a greater magnitude of system capacity during events, but discharge also extended beyond customer load requirements. Excess discharge was being exported to the grid – a behavior from this cohort of systems that wasn't observed ordinarily throughout the year. We also observe increased charging on and after event days because greater discharge utilization resulted in lower end-of-day state-of-charge (SOC). Again, no observed changes in utilization were observed with systems not enrolled in ELRP (pictured on the right). ***We recommend that the CPUC and SGIP PAs continue to encourage participation in DR programs. Programs like the ELRP that compensate customers for export (rather than just reductions in consumption) should be prioritized as they represent an incremental load reduction relative to typical battery dispatch.***

Customer Bill Impacts

One of the key influences on storage utilization and efficiency is how the system is being managed to provide customer benefits. Most nonresidential systems can realize bill savings on the energy and demand portion of their bill. Residential customers are not subject to demand charges, so bill savings result from energy arbitrage exclusively.

SGIP nonresidential storage systems are generally being utilized to reduce non-coincident monthly peak demand and on-peak demand, as well as for TOU energy arbitrage (Section 6.2.1). Systems designed for demand charge reductions may incur increases on the energy component of their bill, but demand reduction savings lead to a net decrease in bills overall. Some nonresidential systems perform TOU arbitrage exclusively, and subsequent charging may lead to increased non-coincident peak demand. This latter finding is observed within non-PV paired critical services facilities incentivized through the Equity Resiliency budget (ERB). Discharging begins in the early afternoon and continues throughout the 4pm – 9pm on-peak period (highlighted in gray within the inset figure). Charging begins overnight, which leads to greater load than the counterfactual.



Despite several individual project outliers with annual bill savings extending above $100 per kWh of capacity, average savings range from over $50 per kWh for standalone large-scale projects to a slight increase in bills for standalone ERB ($1.20 per kWh).

Residential storage systems are being utilized for TOU arbitrage and self-consumption – where the battery is discharged to minimize grid imports throughout the on-peak period as well as after (Section 6.2.1). Residential systems are producing savings on the energy component of bills, especially during summer months when on-peak and off-peak price differentials are high, and systems are utilized more often. Solar PV paired systems are generating annual savings of roughly $10 per kWh of capacity, and standalone system savings were roughly $4 for each kWh of capacity in 2022. Systems conducting TOU arbitrage are realizing roughly double the average savings than systems conducting self-consumption during summer months. However, under-utilized systems and those likely in backup mode are incurring bill increases of roughly $2 for each kWh of capacity.

Utility Avoided Costs

When the timing and magnitude of charge and discharge follow the price signal of a customer tariff or a marginal emissions signal, storage performance can lead to customer bill savings, and avoided GHG emissions. The same is true for utility costs. When paired with on-site PV, storage systems are discharging exclusively on-peak or on-peak *and* to zero out delivered load. Furthermore, some storage systems are discharging beyond BTM consumption and exporting the excess energy to the grid during on-peak hours. Export is standard daily practice for some groups of systems and wholly event based (ELRP, for example) for other groups. Either way, these behaviors are advantageous from a customer bill, GHG, and utility avoided cost perspective. Generation technologies provide year-round energy to the customer and to the grid, and these continuous benefits result in significant utility avoided cost benefits.

Gas Turbines provided the most significant avoided costs benefits, averaging $817 per kW of capacity (Section 6.5.2). Across all systems, the average avoided cost was $536 per kW of capacity, which was driven by the high energy and generation components. All technologies provided an avoided cost benefit greater than $100 per kW. Non-renewable systems provided the greatest benefits, due to their significant generation contribution throughout the year.

Given the correlation between billed on-peak hours of 4pm-9pm, CAISO net loading, and marginal grid generator emissions to utility costs, observed storage behavior was advantageous from an avoided utility cost perspective in 2021 and 2022 as well (Section 6.5.1). Overall, SGIP storage systems were charging during lower marginal cost periods and discharging during higher cost periods. Marginal costs are highest when energy prices are high and there are significant capacity and transmission and distribution (T&D) constraints. Nonresidential and residential systems were discharging throughout these highly constrained hours. This behavior resulted in a $27 million avoided cost benefit across utilities, with most benefits occurring during a few capacity-constrained high temperature hours in early September 2022.

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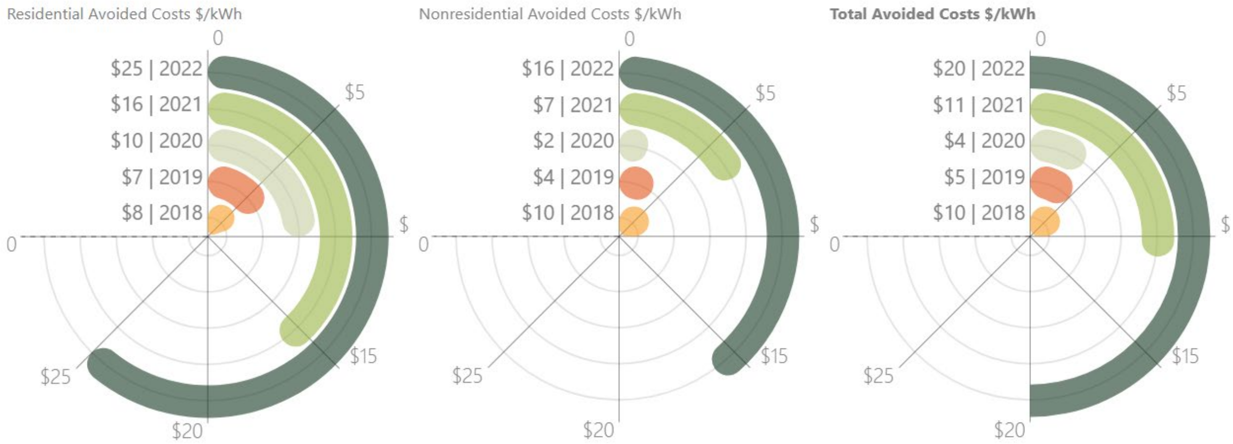
FIGURE 1-4: ENERGY STORAGE UTILITY AVOIDED COSTS ($/KWH) BY YEAR AND SECTOR



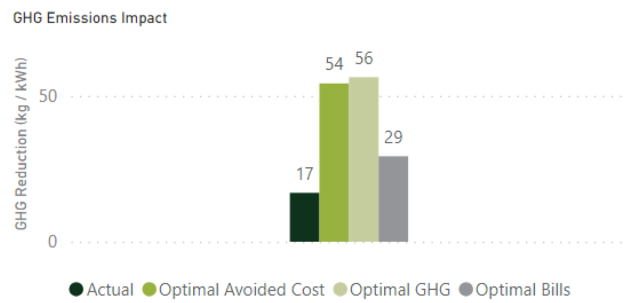
Residential Customer Resiliency and PSPS Events

Residential customers experiencing Public Safety Power Shutoffs (PSPS) utilized their storage systems to provide resiliency during outages in 2021 and 2022 (Section 6.6). Fortunately, the number of PSPS outages – and their duration – throughout California was greatly reduced in 2021 compared to 2020, and PSPS outages in 2022 were even less than in 2021. On non-PSPS days, storage systems are performing normal operations – charging from on-site solar and discharging throughout the on-peak period and after to reduce delivered load from the utility. During PSPS days, storage discharge and solar generation are the only means by which a customer can still service plug loads and critical circuits, so storage discharges much more energy, particularly throughout non-PV generating hours in the evening and overnight. We observe a 60% increase in daily storage discharge during outages when more of the capacity is used for customer resiliency, and 2x greater PV output on non-outage days when it is safe and feasible to export excess solar output to the grid. While customers are consuming more on non-event days, non-zero consumption on outage days highlight the benefits afforded from a paired solar plus storage system to utility customers.

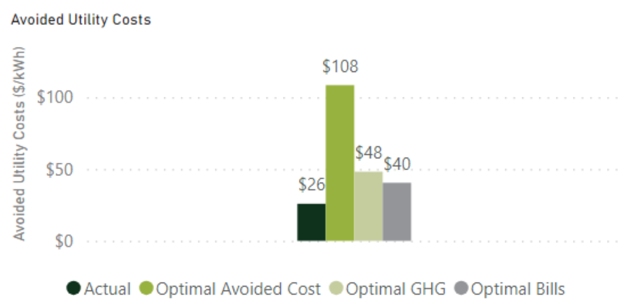
Storage Optimization

A perfectly designed energy storage system optimized to reduce GHG emissions or respond to grid emergencies would charge only during the lowest marginal emissions or utility cost periods and discharge during on-peak hours only (Section 6.7). Obviously, storage project developers and host customers may not be aware of system-level peak hours, energy prices, or marginal emissions unless they are enrolled in a demand response program or real-time pricing rate where a price signal (or incentive) encourages shifting or reducing demand at specific times. Customers have access to their bill rate structure, but grid-level demand may not be in their purview. On-peak TOU periods provide a broad signal to arbitrage energy over a five-hour period, but emissions vary considerably during this period, narrowing the window for achievement of maximum emissions reductions or utility avoided costs.

Optimization modeling revealed that the average actual avoided emissions of 17 kg of GHG per kWh of capacity would triple if optimized for GHG reductions or utility avoided costs. They would almost double if customer bill savings were optimized (Section 6.7). Verdant compared observed storage performance to optimal performance following the hourly marginal emissions factor, utility avoided costs, and customer rate schedules. Observed GHG emissions reductions in 2022 and potential reductions achievable following these different signals are all significantly greater than zero. ***<u>We recommend that the CPUC revisit the 5 kg/kWh GHG reduction target and consider replacing it with a more ambitious target that reflects improvements in technology to maximize its potential.</u>***



Optimizing residential charge and discharge for utility avoided cost benefits would result in a 4.5x improvement over actual avoided cost benefits in 2022. Avoided cost benefits would also increase if GHG emissions or bill savings were optimized, but at lower magnitudes (Section 6.7). Optimization modeling revealed that the average actual avoided cost benefit of $26 per kWh of capacity would increase to $108 if storage followed the avoided cost signal. Most of the incremental avoided cost benefits under this optimization scenario – compared to the GHG optimization scenario – are realized during several capacity constrained hours in late summer. ***<u>We recommend the CPUC continue to explore strategies to encourage SGIP participants to enroll in DR or real-time retail rates to encourage increased dispatch during high GHG/demand hours.</u>***



2 INTRODUCTION AND OBJECTIVES

California's Self-Generation Incentive Program (SGIP) provides financial incentives for the installation of behind-the-meter (BTM) distributed generation and energy storage technologies that meet all or a portion of a customer's electricity needs. The SGIP is funded by California's ratepayers and managed by Program Administrators (PAs) representing California's major investor-owned utilities (IOUs). These PAs include Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), Southern California Gas Company and the Center for Sustainable Energy (CSE), which implements the program for customers of San Diego Gas and Electric (SDG&E). The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP.

2.1 HISTORY OF THE SGIP

Since its inception in 2001, the SGIP has provided incentives to a wide variety of distributed energy technologies including combined heat and power (CHP), fuel cells, solar photovoltaic (PV) and wind turbine systems. While the program was initially designed to help address peak electricity problems in California[1], the program has evolved since 2001, with eligibility requirements, program administration and incentive levels all changing over time. Approval of Assembly Bill (AB) 2778[2] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. By 2007, growing concerns with potential air quality impacts prompted changes to the SGIP's eligibility rules, and passage of Senate Bill (SB) 412[3] shifted the program's focus from peak-load reduction to greenhouse gas (GHG) reductions.

Beginning in 2009, energy storage systems that met certain technical parameters and were coupled with eligible SGIP technologies – wind turbines and fuel cells – were eligible for incentives.[4] In 2011, standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – were made eligible for incentives.[5] In 2011, the CPUC issued Decision (D.) 11-09-015, which added SGIP eligibility

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1 California Assembly Bill 970, Ducheny. September 6, 2000. http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html

2 California Assembly Bill 2778, Lieber. September 29, 2006. http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

3 California Senate Bill 412, Kehoe. October 11, 2009. http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

4 CPUC Decision D.08-11-044. November 21, 2008. http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/94272.htm

5 CPUC Decision D.10-02-017. February 25, 2010. http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114312.PDF

requirements based upon GHG reductions. This was followed by D. 16-06-055 in 2016, which, among other changes, revised how the SGIP is administered.[6] Beginning in 2017, the SGIP was administered on a continuous basis. This change was made largely to curb potential issues with incentives being depleted during program opening, as the program is typically oversubscribed. D. 16-06-055 also supplemented the first-come, first-served reservation system with a lottery. In 2017, D. 17-10-004 established the SGIP Equity Budget, where 25% of SGIP funds collected for energy storage projects were reserved for single family and multi-family low-income housing, including disadvantaged communities.[7]

In August of 2019, the CPUC issued D. 19-08-001 approving GHG emission reduction requirements for the SGIP storage budget.[8] This decision requires SGIP PAs to provide a digitally accessible GHG signal that provides marginal GHG emissions factors (kilograms CO_2/kWh) and directs the SGIP storage impact evaluator to provide summary information on the GHG performance of developer fleets as part of annual SGIP storage evaluations. This decision also defined compliance pathways and operational requirements for residential and nonresidential SGIP energy storage projects based on whether a project was “legacy” or “new”.[9]

On September 12, 2019, the CPUC issued D. 19-09-027 that established an SGIP equity resiliency budget, modified existing equity budget incentives, and approved the transfer of unspent funds to the equity resiliency budget.[10] To help deal with critical needs resulting from wildfire risks in the state, D. 19-09-027 set aside a budget for vulnerable households located in Tier 2 and Tier 3 high fire threat districts, critical services facilities serving those districts, and customers located in those districts that participate in low-income/disadvantaged solar generation programs.

More recently, in January of 2020, the CPUC issued D. 20-01-021.[11] The decision authorized the collection of ratepayer funds totaling $166 million per year from 2020 to 2024 across the four program administrators. This decision also increased the financial incentive budget for energy storage technologies

6 CPUC Decision D.16-06-055. June 23, 2016. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=163928075

7 CPUC Decision D. 17-10-004. October 12, 2017. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M197/K215/197215993.PDF

8 CPUC Decision D. 19-08-001. August 9, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=310260347

9 “New” projects are those submitting completed applications on or after 4/1/2020. “Legacy” projects are all others completing applications prior to that date.

10 CPUC Decision D. 19-09-027. September 18, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=313975481

11 CPUC Decision D. 20-01-021. January 27, 2020. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K979/325979689.PDF

to 88% of total SGIP funding. Table 2-1 summarizes the timelines and key provisions from each of those decisions.

TABLE 2-1: CPUC DECISIONS INFLUENCING THE SGIP

CPUC Decision	Decision Date	Key Provisions
D. 08-11-044	11/2008	▪ Energy storage systems that met certain technical parameters and were coupled with eligible SGIP technologies (wind turbines and fuel cells) were eligible for incentives
D. 10-02-017	02/2010	▪ Standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – were made eligible for incentives
D. 11-09-015	09/2011	▪ Modified program to include eligible technologies that achieve GHG emission reductions
D. 16-06-055	06/2016	▪ SGIP administered on a continuous basis ▪ Supplemented the first-come, first-served reservation system with a lottery. ▪ Energy storage allocated 75% of program funds ▪ Required minimum biogas blending requirements, up to 100% biogas requirement starting in 2020.
D. 17-10-004	10/2017	▪ 25% of funds collected for energy storage projects are reserved for the SGIP Equity Budget
D. 19-08-001	08/2019	▪ Requires SGIP PAs to provide a digitally accessible GHG signal ▪ Defines compliance pathways and operational requirements for "new" and "legacy" projects and "developer fleets" ▪ Provided GHG enforcement standards for electrochemical and thermal energy storage systems ▪ Directs the SGIP storage impact evaluator to provide summary information on the GHG performance of developer fleets
D. 19-09-027	09/2019	▪ Established the equity resiliency budget ▪ Modified existing equity budget incentives
D. 20-01-021	01/2020	▪ Authorized ratepayer collections of $166 million per year during 2020-2024 to fund the SGIP ▪ 88% of incentive budget reserved for energy storage technologies ▪ Implemented program revisions pursuant to Senate Bill 700 and other program changes
D. 21-06-005	06/2021	▪ Revised program requirements for renewable generation projects

2.2 REPORT PURPOSE

SGIP eligibility requirements and incentive levels have changed over time in alignment with California's evolving energy landscape. Ongoing evaluation reports serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet its goals. Decision (D.) 16-06-055 initially stated that an SGIP Measurement and Evaluation (M&E) Plan should be developed by CPUC Energy Division (ED) staff in consultation with Program Administrators. The subsequent passage of SB 700[12] extended annual collections of ratepayer funds for the SGIP through 2024 and extended administration of the program through 2025. SB 700 also required the CPUC to adopt new program rules regarding GHG emissions impacts and restricted all SGIP generation technologies to 100% renewable fuel by 2020. Furthermore, Ordering Paragraph (OP) 7(h) of D.19-09-027 required the SGIP program administrators to develop an M&E Plan for 2021-2025, which was ultimately approved in May of 2022, and finalized in January of 2023.

2.3 GOALS AND OBJECTIVES

The primary objective of this study is to satisfy the requirements of the 2021-2025 M&E Plan by evaluating the performance of incentivized SGIP systems operating during calendar years 2021 and 2022. Verdant analyzed several different observed performance metrics and impacts and compared them to expectations and program requirements. The research questions shown below are informed by the M&E Plan, along with results garnered from past impact evaluations.

[12] California Senate Bill 700, Wiener. September 27, 2018. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB700

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TABLE 2-2: OVERVIEW OF RESEARCH OBJECTIVES AND METHODS

Quantitative Research Objectives	Methods
Observed Performance Metrics	
• Are projects maintaining minimum capacity factors, RTEs and cycling requirements? • How have project efficiencies and utilization changed over the years? • How do utilization and system efficiencies (electrical, thermal, and total) differ based on different segmentation – facility type, operating mode, TOU period, season, presence of on-site generation, capacity constrained hours, fuel type? • To what extent do SGIP technologies employ renewable fuel and how does their performance compare to non-renewable and blended projects? • Quantification of electricity generated, fuel consumed (both renewable and non-renewable), and useful heat recovered? • Non-coincident peak demand impacts?	Analysis of metered data for energy storage system charge and discharge, generation system output, and facility load at the utility meter. Optimal dispatch modeling.
Grid Impacts and Utility Marginal Costs	
• How do systems currently operate throughout grid constrained hours (CAISO net peak and gross peak hours) and utility coincident peak? What are the key differences between groups based on different segmentation? • How are resources that charge from renewable generation exporting to the grid? How often? At what times? At what capacities? • How do systems affect utility and grid costs? • Are storage systems exporting and, if so, is export energy renewable based? • Quantification of impacts from systems participating in wholesale markets and demand response?	Comparing CAISO and IOU load data to the metered storage and generation data throughout specific hours throughout the year. Quantification of dispatch behavior throughout demand response and wholesale market participation. Quantification of grid benefits using the Avoided Cost Calculator (ACC), Optimal dispatch modeling.
Environmental Impacts	
• Are projects reducing GHG emissions? Have emissions changed over time? • Do emissions vary by key segmentation – facility type, developer/manufacturer, presence of on-site solar, rate schedule, legacy status, etc? • What are developer fleet emissions? • How does optimal GHG emissions reductions compare to observed emissions and how can changes to operation lead to increased GHG emissions reductions? • Quantification of emissions impacts based on the various emissions components – generation technology by fuel type, electric power plant, heating and cooling, biogas treatment?	Analysis of emissions avoided during storage discharge and emissions increases during storage charging. Comparison of emissions impacts by component for differing technologies, fuels, and baseline types; impact of electric power plant, heating and cooling loads, and biogas treatment. Optimal dispatch modeling.
Integration of On-site Solar PV	
• How does storage interact with systems paired with PV? Does behavior differ for standalone systems and by different segmentation? Do discharge patterns differ by TOU periods? • What is the relationship between storage sizing and PV sizing? How does that relationship correlate to customer, grid, and environmental impacts?	Analyze and quantify storage performance throughout PV generating hours - percentage of energy charged, magnitude of charge relative to size of PV generator (kW, kWh)
Customer Resiliency	
• How does storage behave during outages? • Quantification of BTM consumption during PSPS events compared to similar non-PSPS days? Changes in utilization, consumption, PV generation? • How are critical needs facilities being utilized to provide community support during utility outages?	Analysis of storage, load, and PV data during PSPS and other outage events compared to like days. Review of outage data provided by utilities. Review of program tracking.
Customer Bill Impacts	
• Are SGIP participants realizing bill savings from storage utilization? • Are nonresidential customers realizing demand charge savings? TOU energy savings? • How do customer bill impacts differ by rate schedule, month? • How does optimal bill savings compare to observed customer bill savings? • Co-optimization with GHG reductions or utility avoided costs?	Analysis of changes to a customer's bill from a baseline where no storage exists using Verdant's Bill Calculator and Cost-Effectiveness Tool. Optimal dispatch modeling.
Storage Costs	
• Quantification of self-reported storage costs? What comprises storage eligible costs - capital expenditure, labor, interconnection, permitting? • How have these costs changed over time? Do costs differ by component or by developer/manufacturer?	Analysis of disaggregated eligible costs from program tracking data. Analysis of trends based on developer/manufacturer, size of system, program year of application.
Population Impacts	
• Quantification of storage and generation impacts to the population of the SGIP?	Ratio estimation. Extrapolation of sample-level impacts to the population of projects.

2.4 METHODOLOGY OVERVIEW AND SOURCES OF DATA

The empirically observed impacts reported in this evaluation are based directly on metered performance data collected from a sample of SGIP projects. The evaluation team used sampling methods and estimated population-level impacts using statistical approaches that conform to industry standards for impact evaluations (Section 5). Sources of data used in this evaluation include:

- The SGIP Statewide Project Database – contains project characterization information such as incentivized capacity, host customer address, electric utility, project developer and upfront payment date
- Installation Verification Inspection Reports – used to supplement the Statewide Project Database with additional details such as inverter size (kW), battery size (kWh) and storage system type
- Metered generation, charge, and discharge data
  - Data for systems subject to PBI data collection rules were downloaded from the Statewide Project Database
  - Data for a sample of all energy storage systems (regardless of size) were requested and received from project developers
  - Data for generation systems came from both customers and performance data providers
- Metered customer interval load and tariff information (energy storage) were requested and received from the electric IOUs and project developers, where available
- Marginal emissions data were collected from the GHG signal provider, WattTime[13]
- Utility avoided cost information was developed using locational marginal price and GHG Allowance price data from CAISO, as well as marginal cost data from the CPUC 2022 Avoided Cost Calculator (ACC)
- Additional information such as electric outage information, paired generator (PV, fuel cell, etc.) characteristics and participation in demand response (DR) programs, where applicable, were received from project developers and electric utilities

The data were reviewed to ensure data integrity and quality. Characterization of the sample including performance metrics and program impact estimates by various categorical variables are included in Section 6. Details on the data integrity and quality control (QC) methods are provided in Appendix B.

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[13] https://sgipsignal.com/

2.5 REPORT ORGANIZATION

This report is organized into six sections and five appendices as described below.

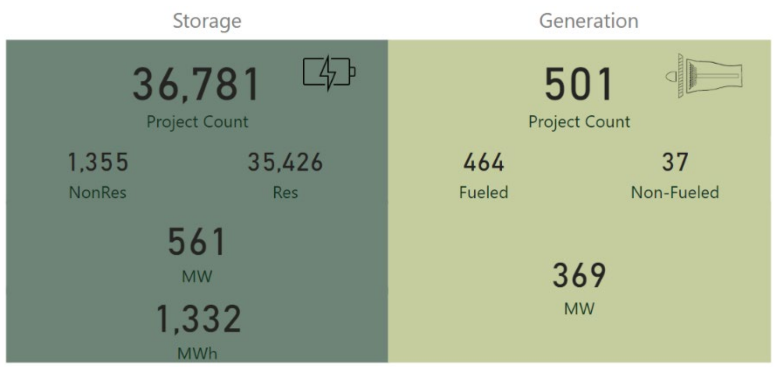
- Section 1 provides an executive summary of the key findings and recommendations from this evaluation
- Section 2 summarizes the purpose, scope, methodology and organization of the report
- Section 3 provides a detailed description of the SGIP population
- Section 4 details the data sources used to develop the sample impacts and overall population impacts
- Section 5 characterizes the metered sample
- Section 6 presents performance metrics and observed impacts for sampled projects, as well as estimated total impacts for the overall population
- Appendix A describes how customer bill impacts were estimated
- Appendix B presents the sources of data used in this evaluation and the quality control procedures used to verify storage data
- Appendix C provides detailed impacts results for calendar year 2021
- Appendix D provides methodologies related to greenhouse gas calculations
- Appendix E provides methodologies related to utility avoided costs

3 STUDIED POPULATION

The 2021-2022 SGIP energy storage and generation population is collected from the most recent version of the statewide project database and downloaded at www.selfgenca.com. This dataset provides the current listing of all projects that have applied to the program and contains important information, including incentive status, project developer name, system size, system location, electric utility name, and whether a project is paired with a renewable generator (among other fields). More recently, as program eligibility and new budget categories have been carved out, the dataset also details whether a participant lives in a Tier 2 or Tier 3 High Fire Threat area or has experienced more than two Public Safety Power Shutoff (PSPS) events.

The energy storage population subject to evaluation is defined as all projects; 1) receiving an upfront SGIP incentive on or before December 31, 2022, *and* 2) having status of "Payment Completed" or "Payment PBI in Process" *and* 3) where equipment type is electrochemical, mechanical, or thermal storage.

FIGURE 3-1: SGIP 2021-2022 EVALUATION POPULATION

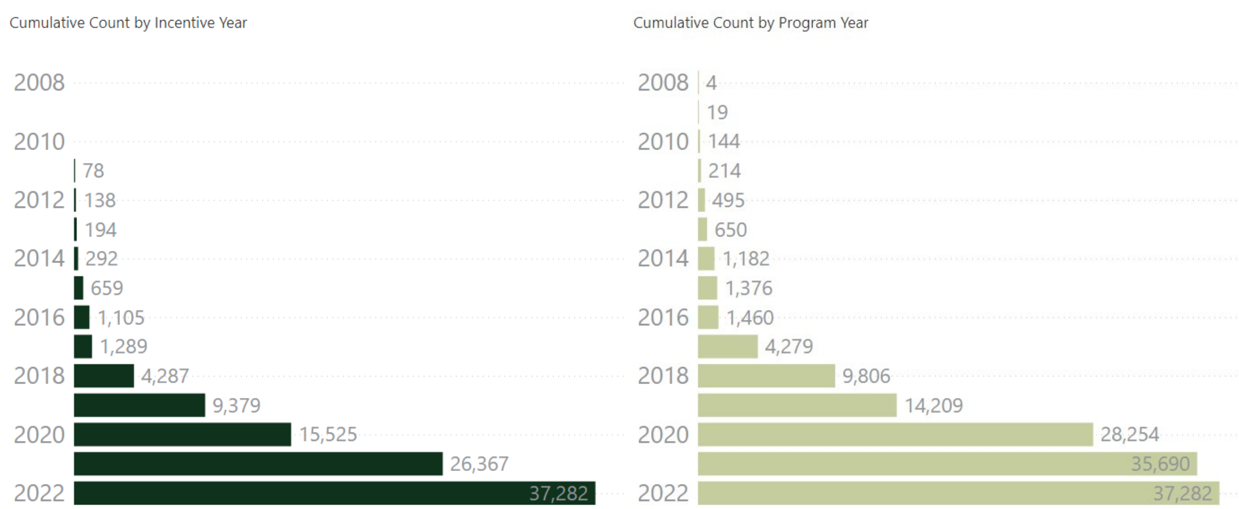


The generation population subject to evaluation is defined as all projects; 1) receiving an upfront SGIP incentive on or before December 31, 2022, *and* 2) having status of "Payment Completed" or "Payment PBI in Process" *and* 3) where equipment type is gas turbine, fuel cell, microturbine, wind turbine, waste heat to power, pressure reduction turbine, or internal combustion engine *and* 4) still within their permanency period as specified by the program handbook.

During 2021-2022 there were over 36,000 storage projects in the population, with over 35,000 of them being residential systems. On the other hand, only 501 generation systems were within the SGIP population, 464 of them were fueled systems, running on either natural gas, renewable fuel, or a blend of both. The program has incentivized over 1,300 MWh of storage capacity, and 370 MW of capacity of generation projects.

Figure 3-2 presents the growth in SGIP over time by program year (PY) and upfront payment (or incentive) year. The program year represents the year a project applied to the SGIP, and the incentive year corresponds to when the participating customer ultimately received their incentive payment. Given potential lag times between program application and system installation, interconnection and administrative requirements, projects may receive their incentive (or upfront payment) a year or two after initially applying to the program. This is evident in the figure below, where the total number of projects applying within a given year is greater than the number of projects subject to evaluation for that year. Since the program application process can extend beyond one calendar year, our team defines the population of SGIP systems subject to evaluation for a given year based on when the customer received their upfront payment, rather than when they initially applied to the program.[14]

FIGURE 3-2: SGIP CUMULATIVE PROJECT COUNT GROWTH OVER TIME



3.1 COMPOSITION OF SGIP ENERGY STORAGE POPULATION

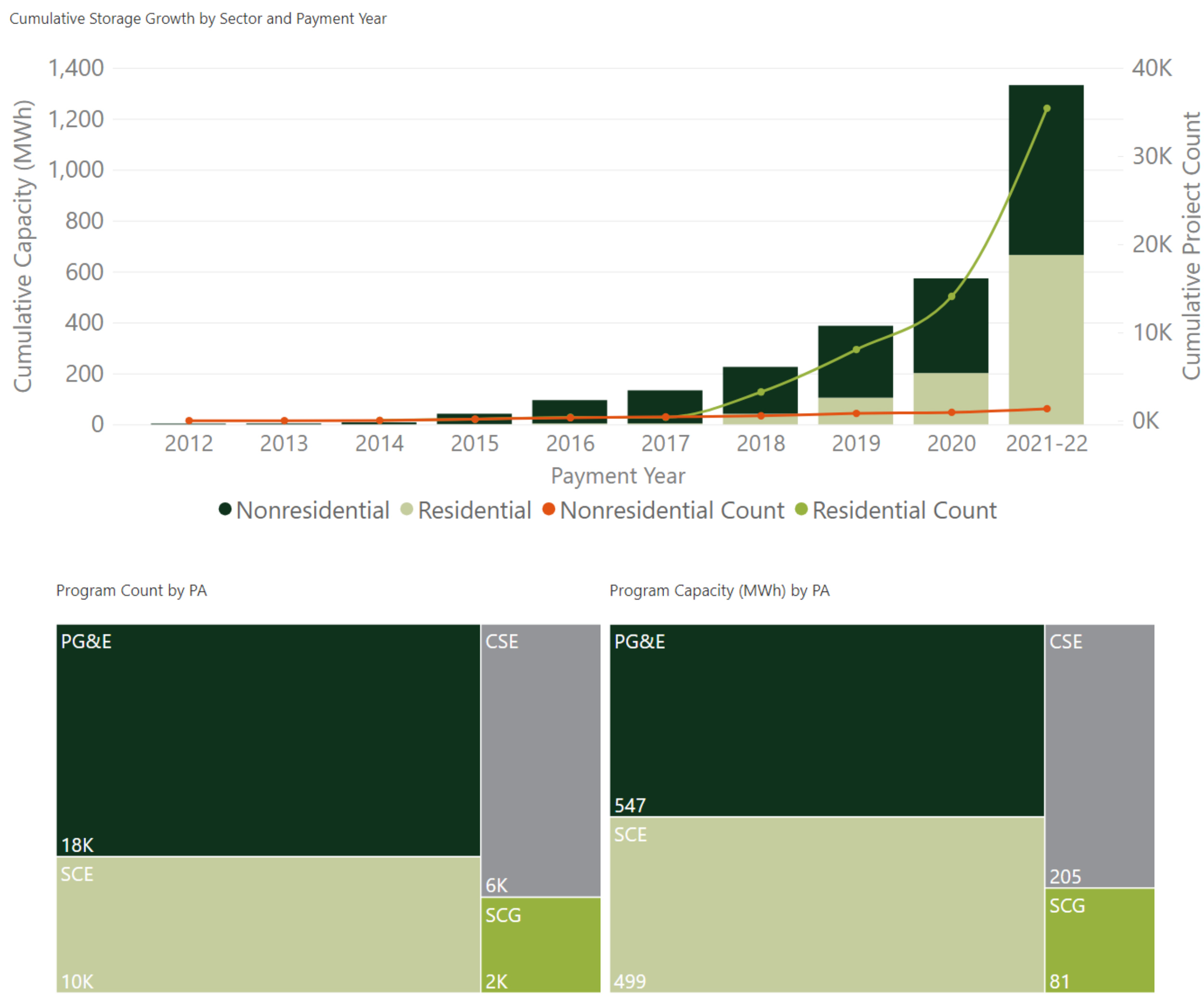
The first step in the evaluation design process was to define the energy storage population subject to evaluation for this 2021-2022 study. Host customers and project applicants are at different stages of the application process at any given time, so initial cut points were created to frame the population and were based on three categories collected from the statewide project database. These categories include 1) all projects that received an upfront SGIP incentive on or before December 31, 2022, *and* 2) have fully qualified state of “Payment Complete” or “Payment PBI in Process” *and* 3) where equipment type is electrochemical, mechanical, or thermal storage. While this impact evaluation covers storage performance throughout 2021 and 2022, the population considers cumulative growth, in that every project receiving an incentive from program inception through the end of 2022 is subject to evaluation.

[14] A participant may apply to the SGIP in 2021, but not receive their incentive payment until 2022. This customer would NOT be part of the population frame for 2021.

Storage Composition by Customer Sector

Figure 3-3 presents the cumulative growth of SGIP incentivized energy storage from 2012 – when the first nonresidential systems received incentives – to the end of 2022.[15] By the end of 2022, the SGIP provided incentives for **35,426 residential** and **1,355 nonresidential** projects representing roughly **666 MWh of incentivized capacity** for each sector. As of December 31, 2022, all but seven were electrochemical (battery) energy storage technologies.[16]

FIGURE 3-3: SGIP STORAGE CUMULATIVE GROWTH BY CUSTOMER SECTOR AND INCENTIVE PAYMENT YEAR

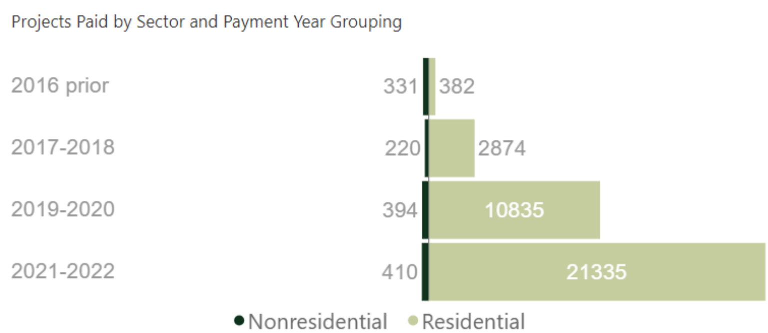


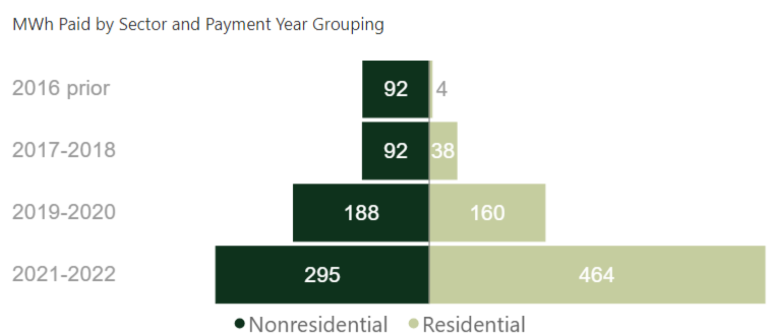
[15] Program composition for 2021 and 2022 have been combined in the figure.

[16] Seven thermal energy storage technologies have received incentives. Two small residential applications, and five nonresidential installations.

Standalone nonresidential energy storage was the predominant technology in earlier years, but new program funding and budget categories with differing incentive levels allowed newer, more sophisticated energy storage configurations access into the program. In 2016, 75% of the SGIP budget was allocated to energy storage and the program began experiencing a significant increase in participation. The overall share of the SGIP budget reserved for storage technologies then increased from 75% to 88% in 2020. These program changes ultimately explain the significant growth in residential program participation, with over 35,000 systems receiving incentives by the end of 2022. Participation in the nonresidential sector has slowed, except for in the Equity Resiliency Budget (ERB) category. While over 90% of the SGIP storage population are residential projects, the program capacity is equally split between the residential and nonresidential sectors. PG&E and SCE constitute the greater share of projects and capacity, followed by CSE and SCG.

The program has more than doubled in size since the most recent impact evaluation was completed for calendar year (CY) 2020. This growth is represented by the 22,000 residential and nonresidential projects receiving SGIP incentives since January 1, 2021, and the 759 MWh of capacity added (inset figure). This coincides with several changes made to the SGIP budget allocation process and program eligibility requirements in 2020. In previous program years the Small Residential Storage budget category, which was open to any residential IOU electric or gas customer, represented over 90% of all SGIP applications. Starting in 2020, the program shifted focus towards equity projects and customer resiliency, which is primarily captured in the equity resiliency budget category.





Storage Composition by Budget Category

The SGIP energy storage budget is broken out into seven categories: Large-Scale, Small Residential, Residential Equity, Equity Resiliency, Nonresidential Equity, San Joaquin Valley Pilot (SJV Pilot) and Heat Pump Water Heaters. The SGIP energy storage budget is 88% of the overall 2020-2024 budget, and the remaining 12% of the budget is reserved for renewable generation technologies. Most of the energy storage budget (63% of the overall 2020-2024 budget) is allocated to the Equity Resiliency budget category with the remaining 25% of the energy storage budget split between the remaining categories. Table 3-1 presents the overall distribution of budget allocation along with a brief description of the budget categories.

TABLE 3-1: DESCRIPTION OF SGIP PY 2020 – 2024 BUDGET CATEGORIES[17]

Budget Category	Budget Allocation	Brief Budget Category Description
Equity Resiliency (Residential and Nonresidential)	63%	▪ Intended for vulnerable households located in Tier 2 and Tier 3 High Fire Threat Districts (HFTDs) or customers who have been subjected to two or more Public Safety Power Shutoff (PSPS) events.
Renewable Generation	12%	▪ Open to generation technologies. All new generation projects must be 100% fueled with renewable fuel.
Large-Scale Storage	10%	▪ Open to **nonresidential projects or residential projects greater than 10 kW.**
Small Residential Storage	7%	▪ Open to **residential projects less than or equal to 10 kW.**
Residential Equity	3%	▪ Open to single-family low-income housing or multi-family low-income housing, regardless of project size.
Nonresidential Equity	n/a	▪ No additional collections authorized. Received funding until exhaustion of previous budget carryover.
San Joaquin Valley Pilot	n/a	▪ No additional collections authorized. Received funding from SCE and PG&E’s unused nonresidential equity budget.

Current budget category designations were not created until PY 2017, so projects applying to the program before then were subject to different eligibility and compliance requirements. Furthermore, the incentive structure changed in PY 2017 from a power output (kW) basis to an energy storage (kWh) basis. Verdant has considered many of the programmatic changes which have shaped the program over the years as we reviewed the statewide program database and designed this study.

Below we highlight the program participant count and system capacity contributions for each budget category throughout the years – Figure 3-4 presents growth in project count and Figure 3-5 presents growth in MWh capacity. Payment years have been combined for ease of presentation, but they generally

[17] D.20-01-021 included a 5% budget allocation for heat pump water heaters (HPWH). The budget for HPWH incentives has since increased. However, the HPWH element of the SGIP is largely independent of the energy storage and generation elements from an administration and evaluation standpoint. As such, changes to the HPWH program are not documented in this report.

align with significant changes to incentive and program structure over time. Projects identified as "2016 Prior" represent those receiving incentives prior to the creation of the current budget categories. Budget categories like Small Residential and Equity Resiliency (ERB), which was created in PY 2020, account for a significant increase in total projects beginning in 2021-2022. Currently, incentives received through the Small Residential budget category represent the largest share of projects, followed by ERB. Measured in program capacity, the Large-Scale Storage category represents the greatest share because this category is open to both residential and nonresidential systems – the latter of which are generally much larger in size. The equity categories have experienced the lowest program participation. By the end of 2022, Small Residential, ERB and Large-Scale Storage represented 97% of all energy storage incentives received within the SGIP since program inception.

FIGURE 3-4: SGIP STORAGE PROJECT COUNT GROWTH BY BUDGET CATEGORY AND PAYMENT YEAR

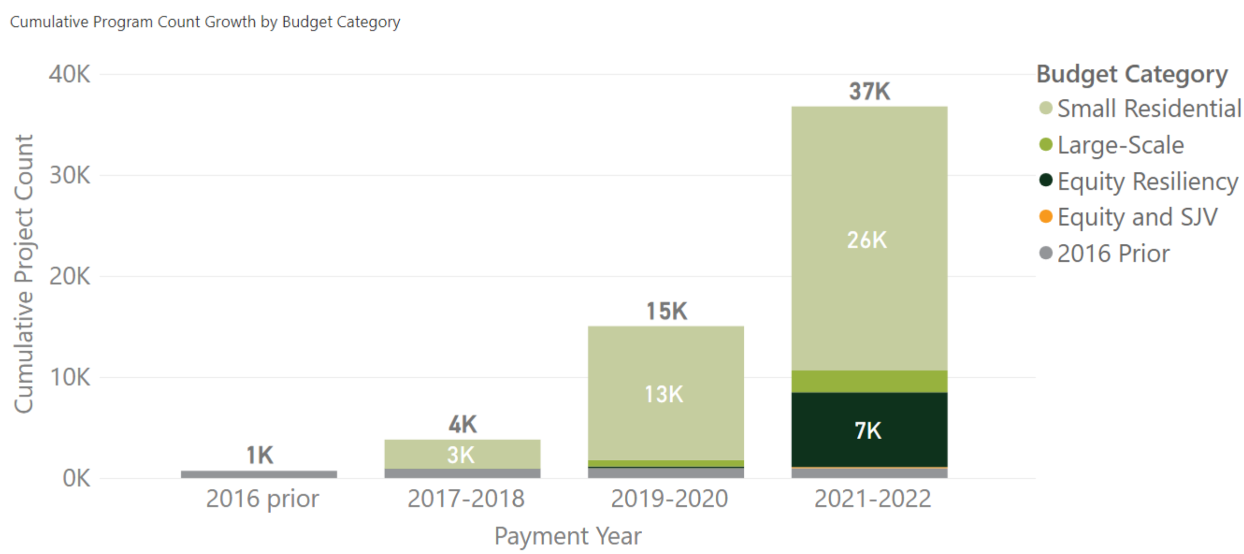
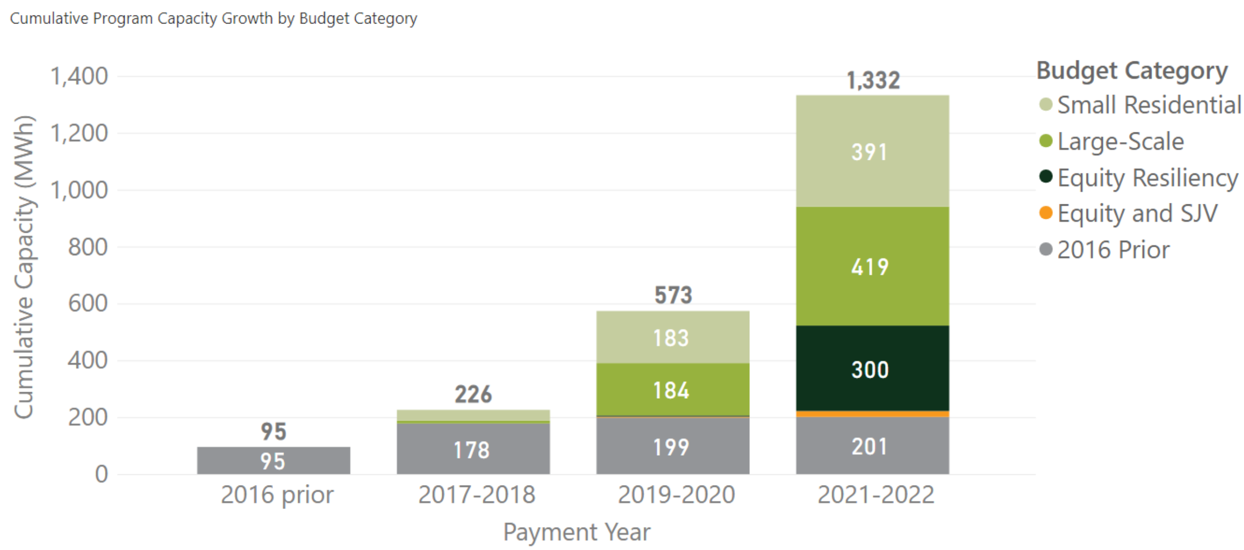


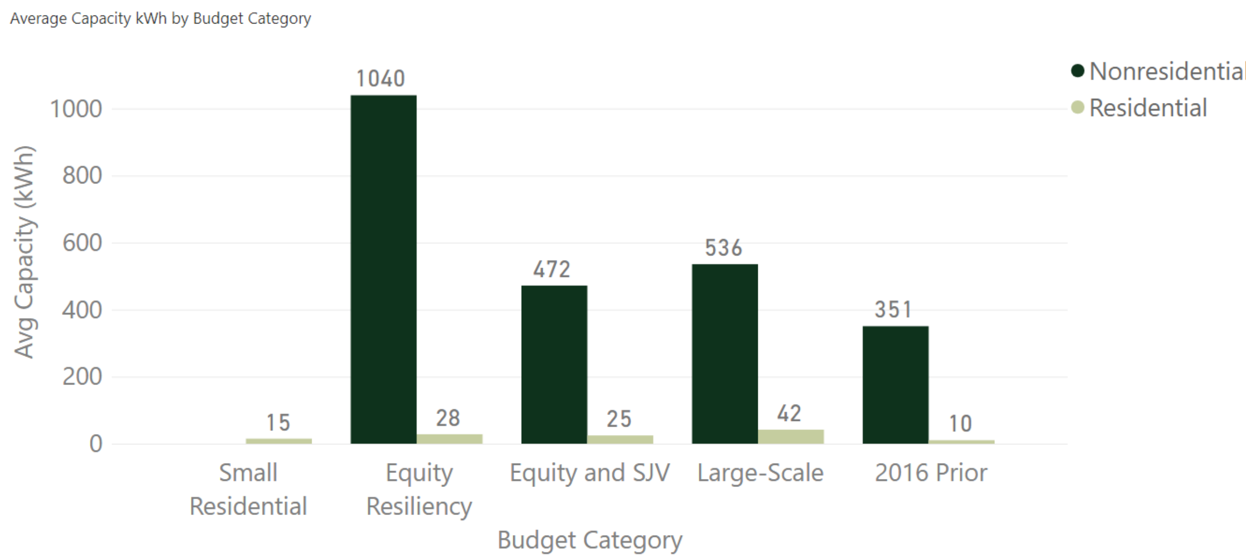
FIGURE 3-5: SGIP STORAGE CAPACITY GROWTH (MWH) BY BUDGET CATEGORY AND PAYMENT YEAR



Nonresidential systems are almost always larger and therefore represent a greater contribution to total program impacts. They range in size from roughly 10 kWh to over 5,000 kWh, with an average capacity of almost 500 kWh. Residential systems generally range from 10 kWh to 40 kWh, with an average capacity of 19 kWh.

We also observe significant variation in installed capacities across budget categories for a given sector. Nonresidential installations in the ERB are, on average, two times larger than nonresidential installations in other budget categories. The ERB installations are installed at critical services facilities, which in the event of an outage, could require larger and longer duration batteries to provide community resiliency. The same is true in the residential sector. Storage systems installed in ERB are, on average, twice the size of Small Residential systems (28 kWh compared to 15 kWh). Customers experiencing PSPS outages and needing to service critical loads like medical devices may require a larger system to provide lifesaving support throughout a multi-day outage. Furthermore, residential customers receiving incentives in Large-Scale Storage might have much greater underlying load requirements than customers in the Small Residential category – which may explain why systems installed in that category are, on average, three times larger than those in the Small Residential budget category.

FIGURE 3-6: AVERAGE INCENTIVIZED CAPACITY (KWH) BY BUDGET CATEGORY AND CUSTOMER SECTOR



Participation within specific budget categories is also influenced by budget allocation (as discussed previously) and upfront incentive levels. The ERB and Equity budget incentives can reach up to $1.00 and $0.85 per watt hour, respectively, while Large-Scale and Small Residential incentives are allocated through a stepdown process – where initial incentives were provided at $0.50 per watt hour, and the incentive is reduced (to as low as $0.15 per watt hour) as stepped participation targets are met and closed, and new steps open.

Figure 3-7 presents how residential incentive levels differ by budget category and over time. The reference line for median incentive ($0.30 per watt hour) is provided to better contextualize how Small Residential and Large-Scale Storage customers installing systems in 2021-2022 are receiving lower incentives than similar customers several years ago. The size of points is proportional to the total count of projects that have received incentives within a budget category. The ERB and SJV Pilot incentives are at or near $1.00 per watt hour and Residential Equity incentives are at $0.85 per watt hour.

Figure 3-8 presents the same data for nonresidential projects.[18] While the nonresidential ERB incentive is also $1.00 per watt hour, this figure presents upfront incentive payments. Nonresidential systems are subject to Performance-based Incentive (PBI) requirements where 50% of the incentive is paid upfront and the remaining 50% is paid out over the next five years and based on project performance. All these projects have received their upfront incentive in 2021 or 2022, so they've only received half or 60% of

[18] The median incentive is akin to the residential sector, given the number of projects and the weight of the step-down incentives in the Large-Scale and Small Residential categories.

their total incentive by the end of 2022. The remaining incentive will be paid over the next several years if minimum performance standards are maintained.

FIGURE 3-7: RESIDENTIAL UPFRONT INCENTIVE BY PAYMENT YEAR AND BUDGET CATEGORY

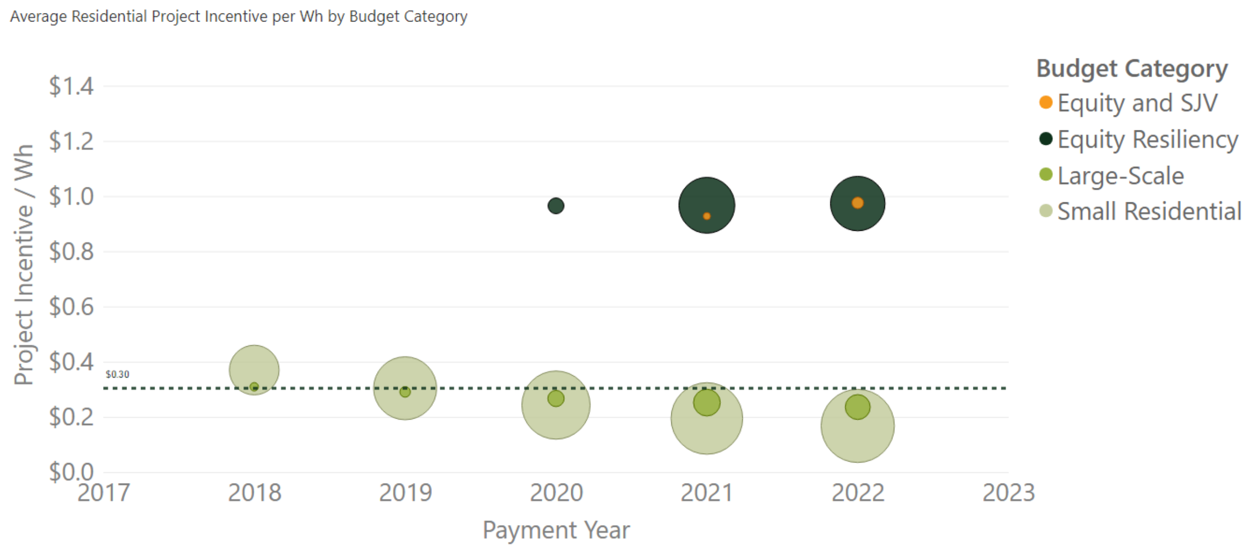
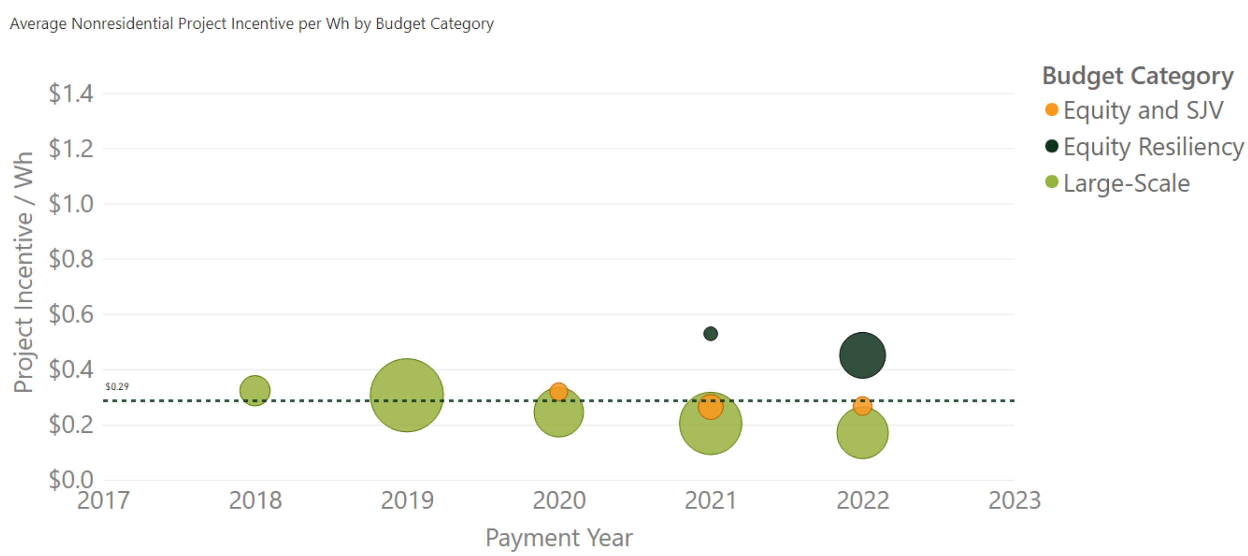


FIGURE 3-8: NONRESIDENTIAL UPFRONT INCENTIVE BY PAYMENT YEAR AND BUDGET CATEGORY

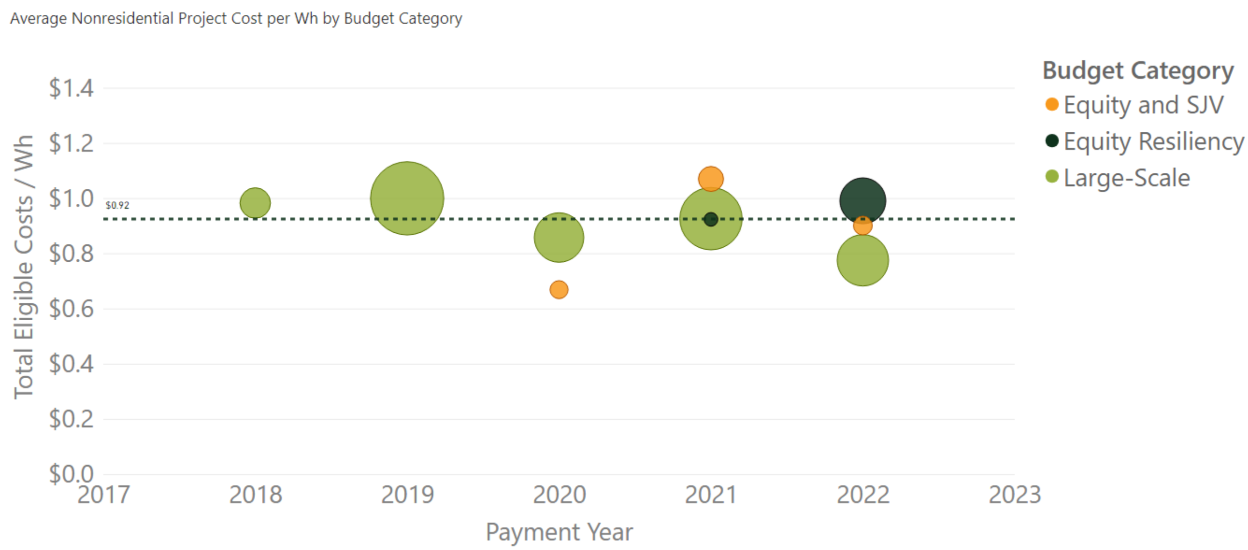


Project developers are also required to detail and submit all eligible costs – design, equipment, labor, interconnection and permitting costs, etc. – and non-eligible costs associated with project installation. In previous program years, these values represented a lump sum. More recently, PAs have requested these cost data be itemized, so storage equipment costs can be viewed separately from labor/installation costs, or interconnection and permitting costs.

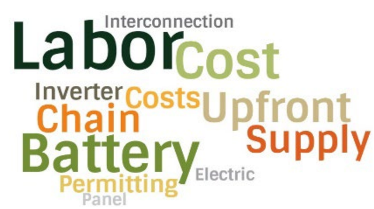
Figure 3-9 and Figure 3-10 convey how, over time, those self-reported eligible costs vary based on customer sector and budget category. Unlike incentive levels, which have either remained constant in categories like the ERB, SJV, and Equity budgets, or have declined like in the Small Residential and Large-Scale Storage categories, total eligible costs have all increased over time. The increase has been independent of the budget category – at least within the residential sector. For example, the average self-reported total eligible cost in the Small Residential category increased from $0.88 per watt hour in 2018 to $1.19 per watt hour in 2022.

FIGURE 3-9: RESIDENTIAL ELIGIBLE COSTS BY PAYMENT YEAR AND BUDGET CATEGORY

FIGURE 3-10: NONRESIDENTIAL ELIGIBLE COSTS BY PAYMENT YEAR AND BUDGET CATEGORY



These increases have been substantiated through market literature – like Energy Sage – and, more directly, through interviews conducted with developers as part of the 2021 SGIP Energy Storage Market Assessment Study.[19] During that study, developers were asked if project costs had increased, decreased, or remained the same over the past two years[20], and if so, by how much. While developer responses to permitting and interconnection cost increases were split, a majority self-reported increases in inverter and battery costs over the past two years. Furthermore, all developers self-reported that labor costs had increased within that time. Self-reported battery and inverter cost increases ranged from 10 to 25% and labor cost increases ranged from 15 to 30%. Developers also self-reported that costs would likely increase over the next two years, but by less than the previous two years.



Storage costs are also impacted by the change in distribution of storage product offerings installed within the SGIP. In the most recent public SGIP evaluation completed for 2020, 98% of residential installations (over 14,000 total) were represented by two equipment manufacturers (labeled as Equip A and Equip B below in Figure 3-11). During this current 2021-2022 evaluation, these systems represented 81% of the

[19] 2021 SGIP Energy Storage Market Assessment Study.
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/sgip-2021-market-assessment-study.pdf

[20] Developer interviews were conducted in 2021.

total 35,000 residential installations, with an increasing market share coming from other product offerings (Equipment C and Equipment D). The changing composition of product offerings in the SGIP signal that the program is maturing and reaching program entrants that either 1) chose not to participate in the program previously and are doing so now or 2) have increased their market share to a point where they can now competitively vie against other companies who previously held greater market share.

FIGURE 3-11: RESIDENTIAL STORAGE INSTALLATIONS BY EQUIPMENT MANUFACTURER AND PAYMENT YEAR

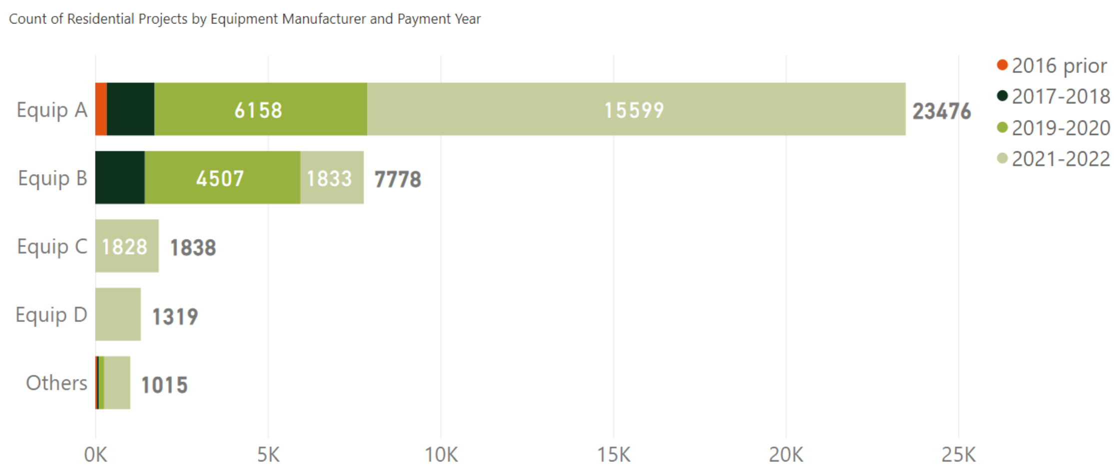
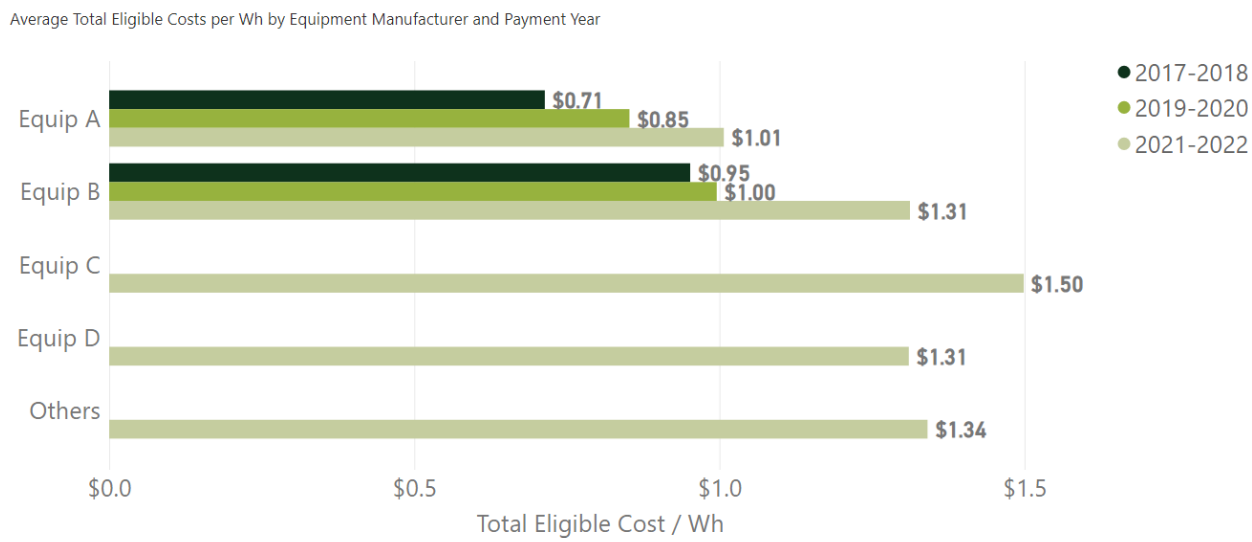


Figure 3-12 presents the average total eligible costs (in dollars per Wh of capacity) for each of the main equipment manufacturers. These costs have also been further disaggregated by payment year to better capture any changes in cost over time. We observe a roughly 40% increase in average costs from 2017-2018 through 2021-2022 for the two predominant equipment manufacturers in the program. More recent program entrants, on average, carry a higher self-reported eligible cost. Currently the median battery cost listed on Energy Sage is $1,339 / kWh[21] (or $1.34 / Wh) so these costs are comparable to those found in the national marketplace.

[21] https://www.energysage.com/energy-storage/ Accessed on 02/01/2024

FIGURE 3-12: RESIDENTIAL ELIGIBLE COSTS PER WH BY EQUIPMENT MANUFACTURER AND PAYMENT YEAR



Steady cost increases and static/declining per-Wh incentives over time have increased the share of costs borne by participating customers. General market participation has been largely unaffected by these increased out-of-pocket expenses, and the ERB has afforded participating customers with a large enough incentive to cover all or most of the system and installation costs. As part of our research, Verdant will continue to track changes in program composition and storage costs to better gauge how a market as dynamic as behind-the-meter energy storage influences SGIP participation (and vice versa).

Figure 3-13 presents the relationship between total eligible costs and residential customer incentives by budget category. Average customer incentives (in total $) are represented on the vertical axis and self-reported eligible costs (in total $) are on the horizontal axis. The graph is split by dark gray shading in the upper left and lighter gray shading in the lower right. Anywhere on that line separating the two areas would suggest that the total incentive covered the entire cost of the system. If below that line and within the light gray area, costs exceed the incentive. Equity and ERB incentives cover almost the entire eligible costs of the systems, whereas costs exceed the incentive in the Small Residential and Large-Scale Budget categories. The median incentive across budget category – roughly $17,000 – is also provided as the horizontal dark dashed line. The median total eligible costs – roughly $27,000 – are provided as the vertical red dashed line. Results for the nonresidential sector follow in Figure 3-14.

FIGURE 3-13: RESIDENTIAL ELIGIBLE COSTS VERSUS INCENTIVES BY BUDGET CATEGORY

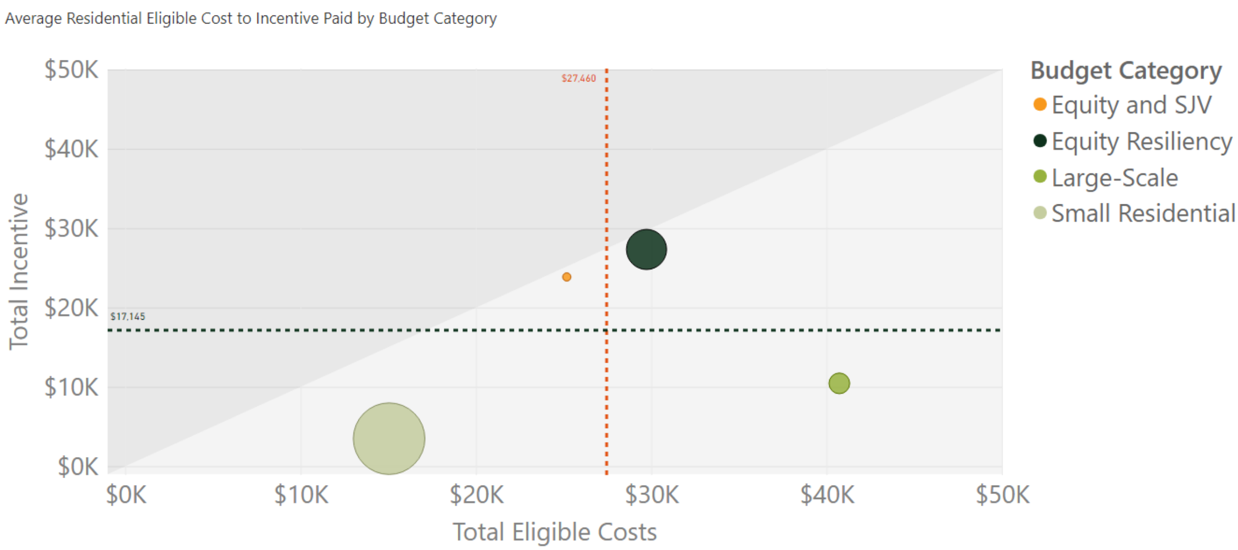


FIGURE 3-14: NONRESIDENTIAL ELIGIBLE COSTS VERSUS INCENTIVES BY BUDGET CATEGORY

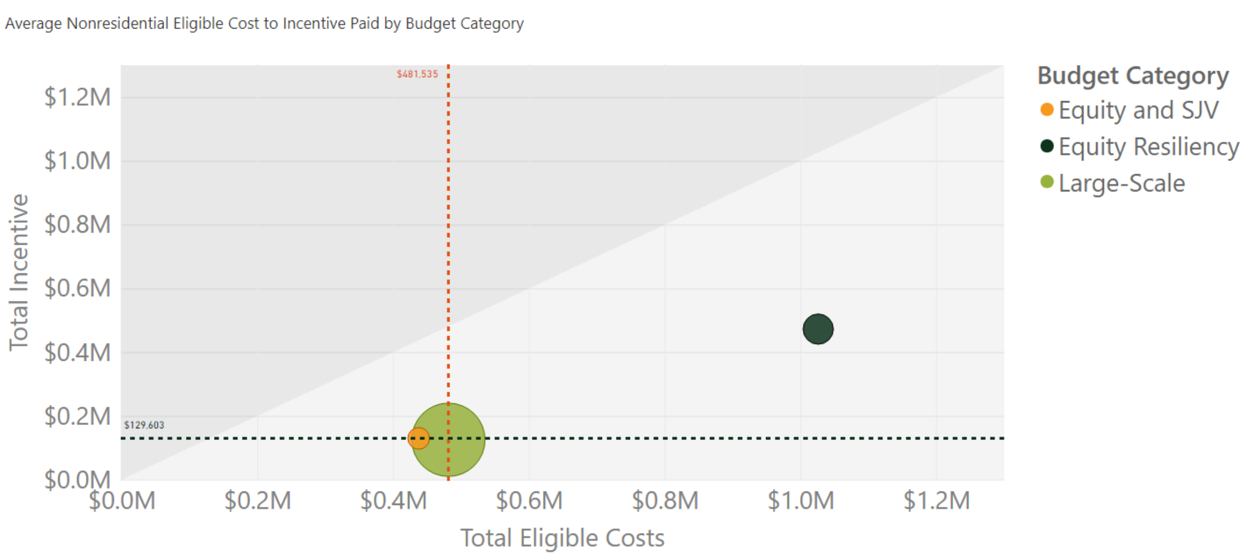


Table 3-2 summarizes the above information and includes, for each budget category and payment year grouping (the years in which the incentive was actually paid out); 1) total project counts, 2) average system sizes (kWh), and 3) average eligible costs, incentives, and out-of-pocket expenses per watt hour of capacity.[22] For ERB participants in 2021-2022, the SGIP incentive covered all but $2,500 ($0.09 per watt

[22] Out-of-pocket expenses don't consider any credits claimed through the Federal Investment Tax Credit (ITC).

hour of capacity) of the roughly $30,500 average total eligible costs. In 2017-2018, the incentive covered roughly 56% of the total eligible costs for Small Residential participants. By 2021-2022, with increased eligible costs and reduced incentive levels, participants were responsible for roughly $15,000 of the $18,000 project installation ($0.93 per watt hour of capacity).

TABLE 3-2: AVERAGE RESIDENTIAL INCENTIVES AND COSTS BY BUDGET CATEGORY AND PAYMENT YEAR

Budget Category	Payment Year	Project Count	kWh	Eligible Cost/Wh	Incentive/Wh	Out-of-Pocket/Wh
Equity and SJV	2021-2022	70	25	$1.03	$0.97	$0.05
Equity Resiliency	2019-2020	169	24	$1.04	$0.96	$0.07
Equity Resiliency	2021-2022	7146	28	$1.06	$0.97	$0.09
Large-Scale	2017-2018	18	35	$0.80	$0.31	$0.49
Large-Scale	2019-2020	228	44	$0.85	$0.27	$0.58
Large-Scale	2021-2022	1247	42	$1.00	$0.24	$0.76
Small Residential	2017-2018	2831	13	$0.81	$0.37	$0.44
Small Residential	2019-2020	10436	14	$0.90	$0.27	$0.63
Small Residential	2021-2022	12870	16	$1.11	$0.18	$0.93
Total		**35015**	**19**	**$1.02**	**$0.46**	**$0.55**

Summaries from the nonresidential sector are also presented in Table 3-3. Again, incentive estimates represent upfront payment amounts, and nonresidential customers are subject to PBI requirements where 50% of the incentive is paid upfront. Most of these customers have or will recover the subsequent 50% of the incentive over five years from the time of the upfront payment (depending on performance and compliance).

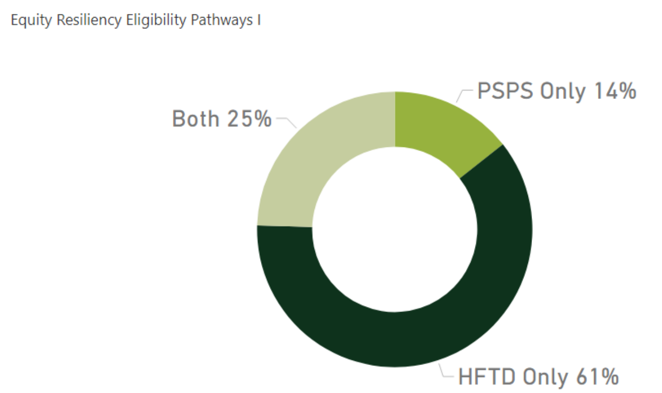
TABLE 3-3: AVERAGE NONRESIDENTIAL INCENTIVES AND COSTS BY BUDGET CATEGORY AND PAYMENT YEAR

Budget Category	Payment Year	Project Count	kWh	Eligible Cost/Wh	Incentive/Wh	Out-of-Pocket/Wh
Equity and SJV	2019-2020	9	371	$0.67	$0.32	$0.35
Equity and SJV	2021-2022	31	501	$0.98	$0.27	$0.72
Equity Resiliency	2021-2022	91	1040	$0.99	$0.45	$0.53
Large-Scale	2017-2018	34	293	$0.98	$0.32	$0.66
Large-Scale	2019-2020	345	475	$0.93	$0.28	$0.65
Large-Scale	2021-2022	283	639	$0.87	$0.19	$0.68
Total		**793**	**590**	**$0.92**	**$0.28**	**$0.64**

Storage Composition by Eligibility Criteria

Budget categories have different criteria which guide the types of installations eligible for a given incentive. Some are exclusively predicated on the size of the system like in the Small Residential or Large-Scale Storage budgets, and some have strict income qualification minimums or a requirement to be installed in a disadvantaged community. The ERB is unique in that it has two eligibility criteria, each having mandatory pathways to secure incentives. The first pathway is available for systems installed within a Tier 2 or Tier 3 HFTD, or if the host customer recently experienced at least two PSPS events. As of the end of 2022, most installations – 86% of ERB participants – were in HFTDs, with 14% qualifying for this eligibility pathway based on PSPS history.

FIGURE 3-15: EQUITY RESILIENCY ELIGIBILITY PATHWAYS 1



The second eligibility criterion considers other demographic, property, and participant information. Evident in the inset figure, most participants secured eligibility through having a medical baseline (66%) or an electric well pump installed at the property (30%). Very few low-income participants (2% of all ERB installations) garnered incentives within the ERB category or used that eligibility pathway. The remaining 2% either provided critical services or the installation occurred in conjunction with a low-income solar program like SASH.

FIGURE 3-16: EQUITY RESILIENCY ELIGIBILITY PATHWAYS 2

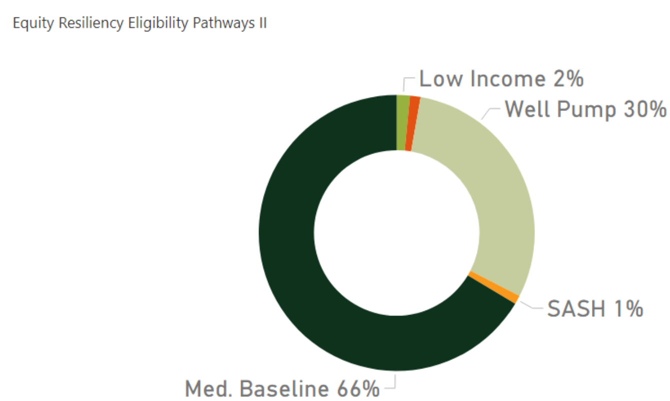
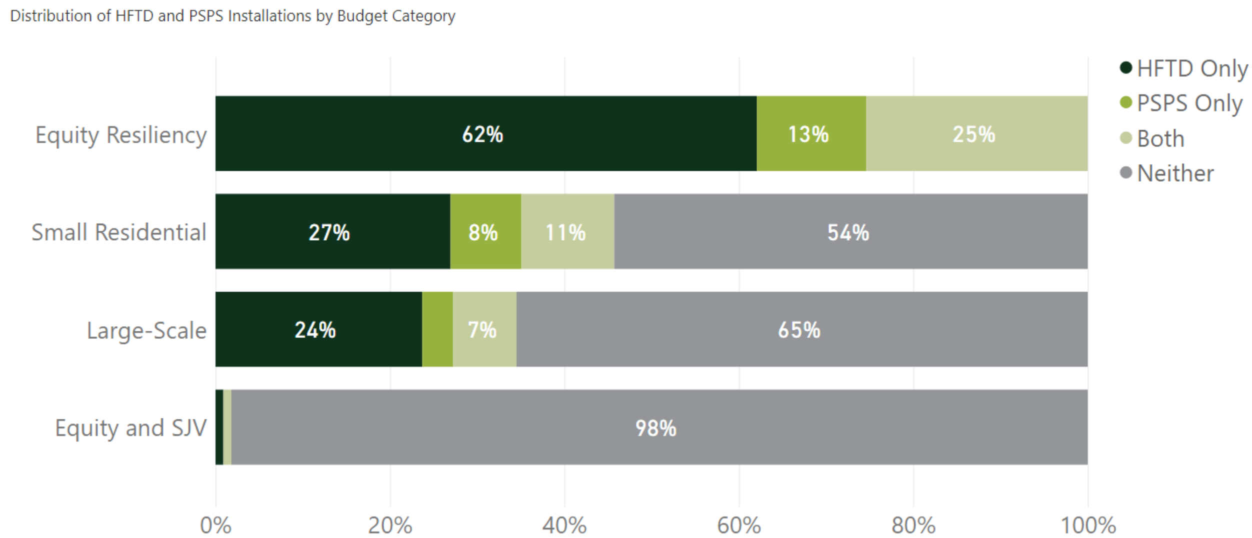


Figure 3-17 also presents the first eligibility criterion for ERB participants along with where and if participants from other budget categories installed systems in HFTDs and/or experienced PSPS events. These other budget categories don't have the same eligibility requirements (or the up to $1.00 per watt hour incentive), so they were likely installing energy storage for personal resiliency without qualifying for the ERB incentive or they participated in the program prior to the creation of the ERB. Almost half (46%)

of Small Residential and nearly 35% of Large-Scale Storage installations have occurred in HFTDs, PSPS areas, or both.

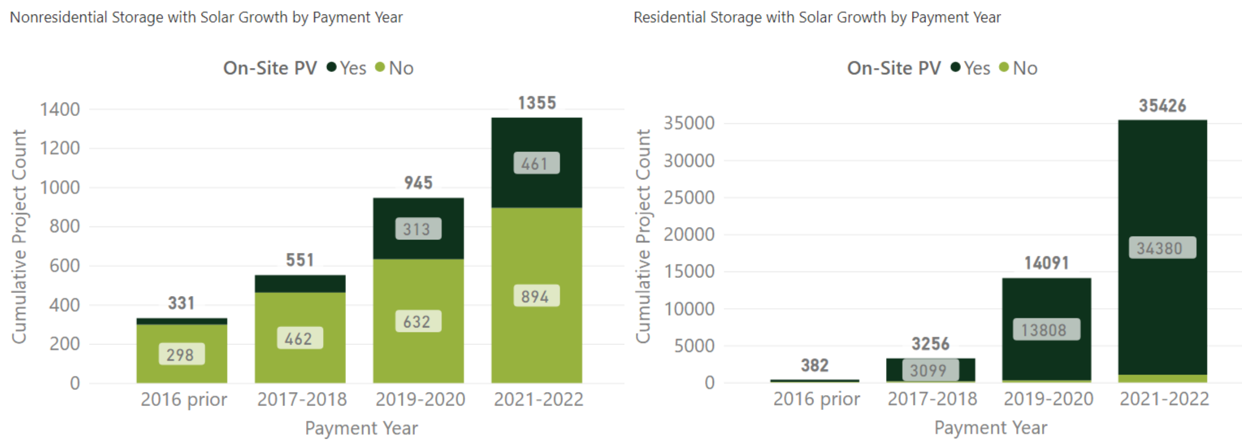
FIGURE 3-17: DISTRIBUTION OF HFTD AND PSPS INSTALLATIONS BY BUDGET CATEGORY



Storage Composition by On-Site Solar Generation

Verdant has also been tracking on-site solar attachment rates for SGIP energy storage participants for over a decade. While D. 10-02-017 made standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – eligible for incentives, solar PV attachment rates within the SGIP didn't really tick up in the nonresidential sector until 2019 when a large fleet of solar plus storage paired systems began receiving incentives. Early residential storage installations were standalone, but when the program began allocating sufficient resources and funding to residential customers in 2017, the program saw a significant increase in solar plus storage installations, along with storage installations retrofit onto existing solar PV. Currently, PV attachment rates are 34% in the nonresidential sector and 97% in the residential sector.

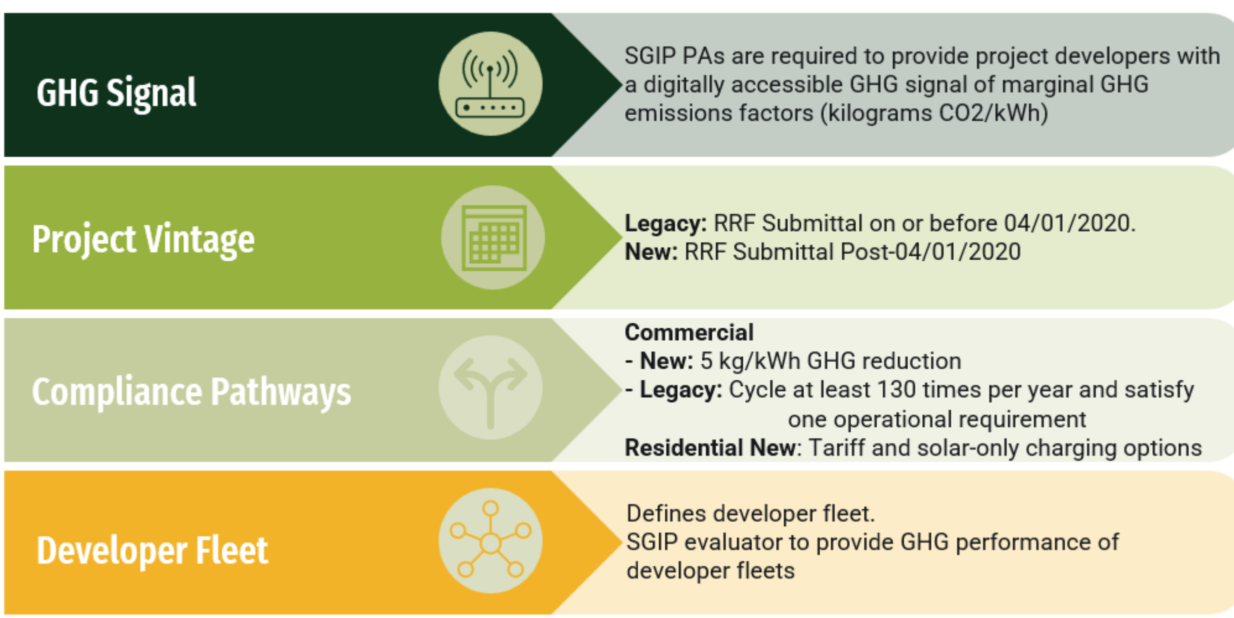
FIGURE 3-18: STORAGE COMPOSITION BY PRESENCE OF ON-SITE SOLAR GENERATION



Storage Composition by Developer Legacy Status

Decision 19-08-001 approved the greenhouse gas emission reduction requirements for the SGIP storage budget. Figure 3-19 highlights the key provisions set forth in the decision.

FIGURE 3-19: GREENHOUSE GAS EMISSIONS REDUCTION REQUIREMENTS FROM D.19-08-001



This decision was approved in 2019 and was instituted in PY 2020, so the GHG emission reporting for this impact evaluation is limited to Legacy nonresidential and residential developer fleets. New nonresidential and residential projects are ALL within their first or second year of permanency in 2021 or 2022, so GHG reporting is NOT required for this evaluation, per the decision. However, the M&E plan calls for an impact evaluation of the program, so New residential and nonresidential systems need to be included in the context of program impacts – the evaluator is just not required to include these systems in the fleet level GHG emissions reporting.

Figure 3-20 presents the over 35,000 residential systems subject to evaluation for this 2021-2022 study by payment year and vintage. Verdant evaluated few New projects in the 2020 impact evaluation given the timing on the Decision and the SGIP application cutoff of April 1, 2020. With the significant influx of new funding and completed applications after April 1, 2020, there are now over 20,000 New systems requiring evaluation, along with 16,000 Legacy systems. Developer GHG impacts are required for the 16,000 projects, if they constitute a developer fleet, and while there is no developer specific GHG reporting requirement for the 20,000 New systems until year five of permanency, Verdant developed impacts for them to meet overall program impact evaluation goals.

FIGURE 3-20: NEW VERSUS LEGACY RESIDENTIAL SGIP PROJECTS

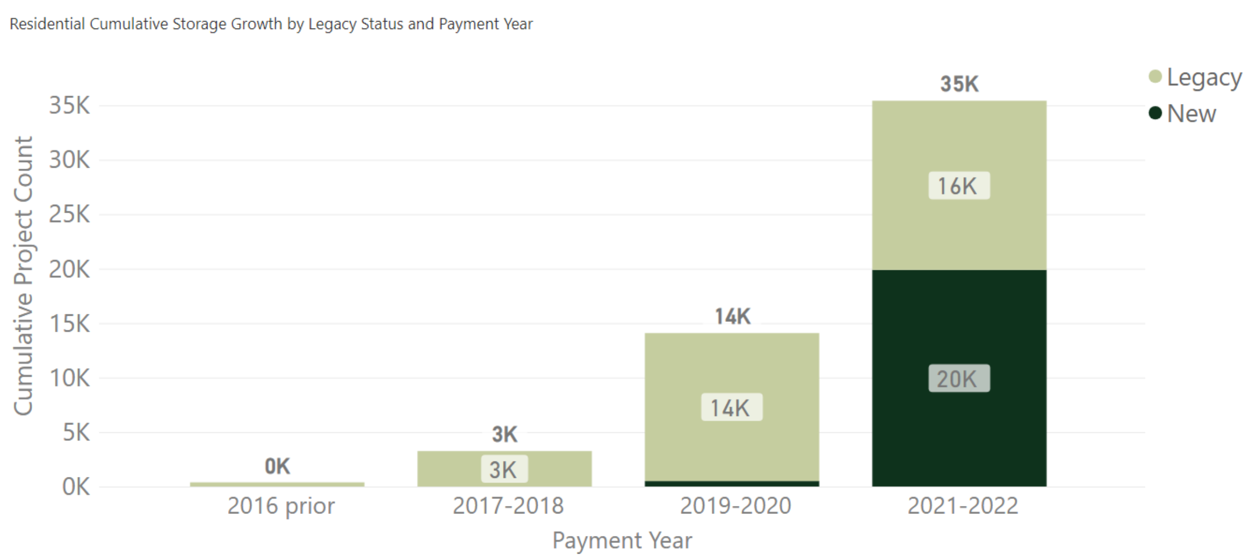
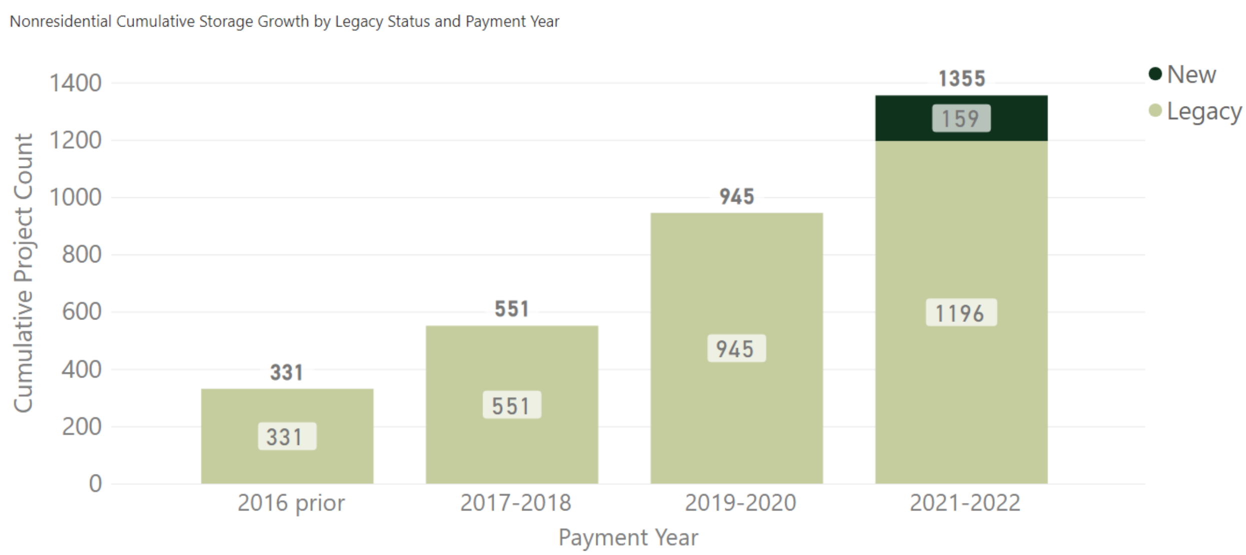


Figure 3-21 presents the New versus Legacy status for the nonresidential sector. Given the greater average lag times between the program initial RRF program application submittal to eventual upfront incentive payment, and the recent slowing of nonresidential application submissions, 88% of nonresidential projects subject to evaluation in this study are Legacy. There are 1,355 nonresidential systems subject to evaluation in 2022, with 1,196 of those defined as Legacy systems. Only 159 projects in this sector had completed their program application on or after April 1, 2020 *and* received their upfront incentive payment prior to the end of 2022.

FIGURE 3-21: NEW VERSUS LEGACY NONRESIDENTIAL SGIP PROJECTS



3.2 COMPOSITION OF SGIP GENERATION POPULATION

Figure 3-22 highlights the growth in SGIP incentivized generation capacity since program inception through 2022. The program year (PY) on the horizontal axis represents the year a project applied to the SGIP. By the end of 2022, the SGIP provided incentives for 501 generation projects representing 369 MW of incentivized capacity. Due to changes in the SGIP for generation technologies, since 2017, the number of project applications resulting in incentive payments has dropped off significantly. This dramatic decrease in projects shows the impact changes in program fuel requirements have had on participation levels. As can be seen below, the last paid projects were PY 2020 projects.

FIGURE 3-22: SGIP GENERATION CUMULATIVE GROWTH BY EQUIPMENT TYPE AND PROGRAM YEAR

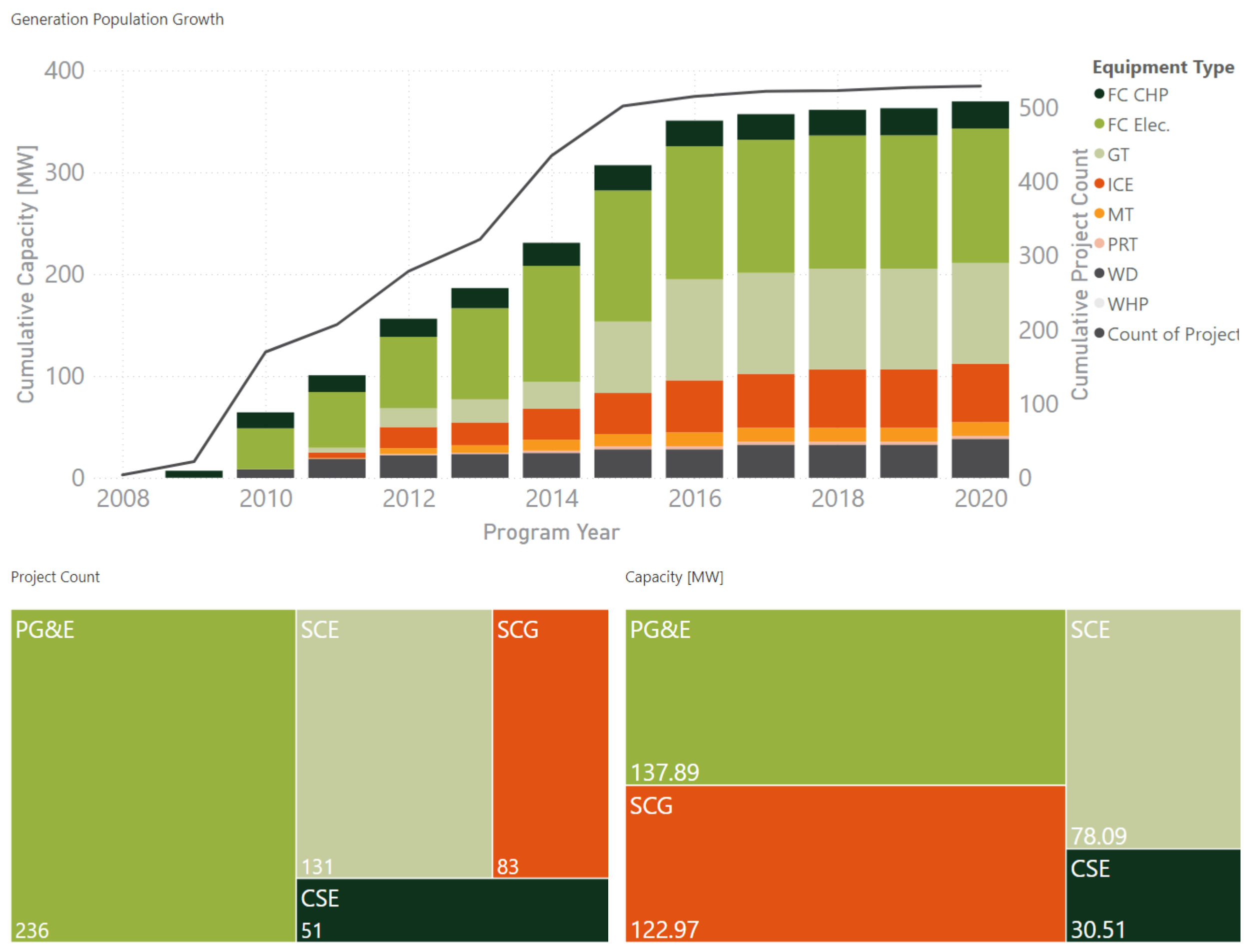


Table 3-4 shows the number of paid projects that fall under the newer SGIP rules, requiring an escalating percentage of renewable fuel. Since PY 2017, only 14 projects have been paid, half of them being wind turbine projects.

TABLE 3-4: SGIP GENERATION PAID PROJECTS SINCE 2017

Equipment Type	2017		2018		2019		2020		Total	
	Count	MW	Count	MW	Count	MW	Count	MW	Count	MW
Fuel Cell Electric	--	--	--	--	1	0.20	1	1.00	2	1.20
Fuel Cell CHP	--	--	--	--	1	1.40	--	--	1	1.40
Internal Combustion Engine	3	1.91	1	4.20	--	--	--	--	4	6.11
Wind	4	4.44	--	--	2	0.02	1	5.64	7	10.11
Total	**7**	**6.36**	**1**	**4.20**	**4**	**1.62**	**2**	**6.64**	**14**	**18.82**

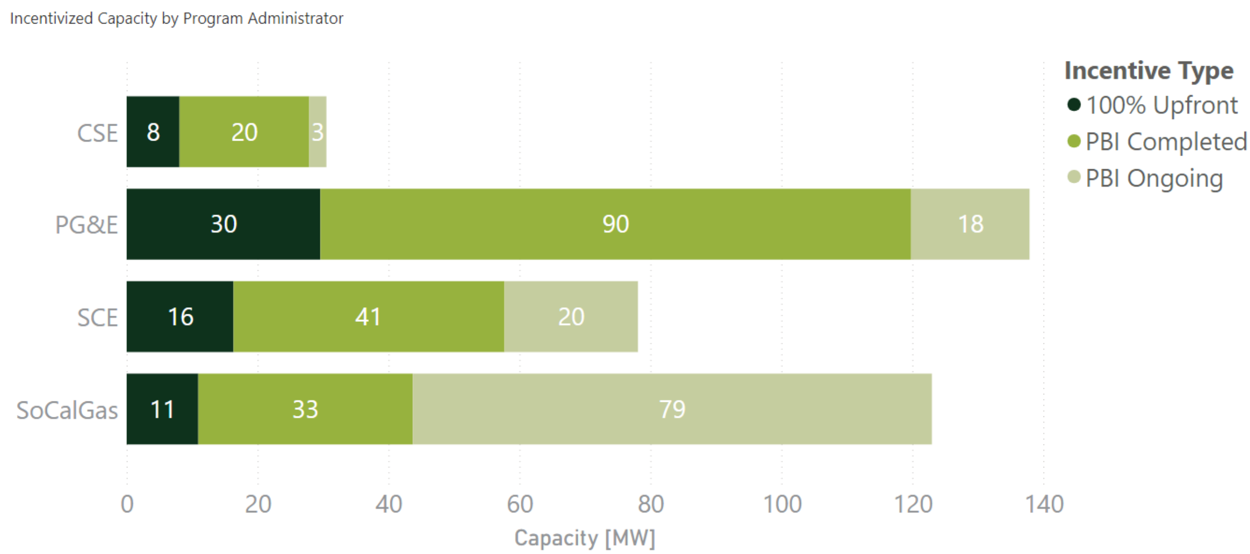
PG&E accounted for most of the generation projects in the population, with a total of 236 projects. Table 3-5 displays both the project count and the rebated capacity by technology. Over 50% of these, by project count, were fuel cell electric equipment. While SCE made up the next largest share of projects, at 131, SoCalGas made up the next largest share of rebated capacity due to the large gas turbine projects they incentivized.

TABLE 3-5: PROJECT COUNT AND INCENTIVIZED CAPACITY BY PROGRAM ADMINISTRATOR

Equipment Type	CSE		PG&E		SCE		SoCalGas	
	Count	MW	Count	MW	Count	MW	Count	MW
Fuel Cell Electric	31 *(61%)*	10.80 *(35%)*	144 *(61%)*	62.86 *(46%)*	95 *(73%)*	32.44 *(42%)*	48 *(58%)*	25.80 *(21%)*
Fuel Cell CHP	11 *(22%)*	6.68 *(22%)*	29 *(12%)*	7.19 *(5%)*	8 *(6%)*	4.66 *(6%)*	21 *(25%)*	7.89 *(6%)*
Gas Turbine	2 *(4%)*	8.97 *(29%)*	1 *(0%)*	9.56 *(7%)*	--	--	5 *(6%)*	80.54 *(65%)*
Internal Combustion Engine	4 *(8%)*	2.04 *(7%)*	32 *(14%)*	29.10 *(21%)*	10 *(8%)*	21.26 *(27%)*	5 *(6%)*	4.83 *(4%)*
Microturbine	--	--	10 *(4%)*	5.30 *(4%)*	4 *(3%)*	4.30 *(6%)*	4 *(5%)*	3.92 *(3%)*
Wind	1 *(2%)*	1.00 *(3%)*	17 *(7%)*	23.08 *(17%)*	9 *(7%)*	14.09 *(18%)*	--	--
Pressure Reduction Turbine	2 *(4%)*	1.02 *(3%)*	2 *(1%)*	0.67 *(0%)*	5 *(4%)*	1.34 *(2%)*	--	--
Waste Heat to Power	--	--	1 *(0%)*	0.13 *(0%)*	--	--	--	--
Total	**51** ***(100%)***	**30.51** ***(100%)***	**236** ***(100%)***	**137.89** ***(100%)***	**131** ***(100%)***	**78.09** ***(100%)***	**83** ***(100%)***	**122.97** ***(100%)***

All generation projects greater than 30 kW are now required to take performance-based incentives, meaning that 50% of the incentive is paid up front, and the remaining 50% is paid over 5 years, depending on how the system is performing. However, prior to PY2011, all projects received the entire incentive up front upon project completion. Figure 3-23 below highlights the incentivized capacity by program administrator and by incentive type. Most of the projects in the generation population were once PBI projects which have now expired and are past their 5-year reporting requirements and have had all incentives paid out. CSE and PG&E still have a larger share of projects which received capacity-based incentives than those that are still within their PBI payment period.

FIGURE 3-23: INCENTIVIZED CAPACITY BY PROGRAM ADMINISTRATOR AND INCENTIVE TYPE



4 DATA SOURCES

This section outlines the key primary and secondary sources of information that inform the analysis for the impact evaluation. The type of data requested from each of the sources is also provided. Figure 4-1 is a matrix of data elements and data sources that are critical to the impact evaluation.

FIGURE 4-1: PRIMARY DATA ELEMENTS AND DATA SOURCES

	SGIP Project Database	Developers/ Manufacturers	IOU or PA	Host Customers	ACC/WattTime
Customer information data	■	■	■	■	□
Facility type and characteristics	■	■	■	■	□
Equipment specifications	■	■	■	■	□
Project incentive/cost details	■	■	□	□	□
Budget category	■	□	□	□	□
Project developer/manufacturer	■	■	□	□	□
Metered equipment data	■	■	■	■	□
Customer load data	□	■	■	□	□
Renewable on-site generation	□	■	■	□	□
Storage operating mode	□	■	□	□	□
Customer utility tariff	□	■	■	□	□
DR and market participation	□	■	■	□	□
Planned/unplanned outages	□	■	■	□	□
SubLAP and circuit information	□	□	■	□	□
Inspection reports	□	□	■	□	□
Operational status	□	□	□	■	□
Utility cost and emissions data	□	□	□	□	■

4.1 SGIP STATEWIDE PROJECT DATABASE

The evaluation team utilized the most recent version of the statewide project list from www.selfgenca.com. The database is managed by Energy Solutions and includes a listing of all projects that were installed and received SGIP incentives. The 2021-2022 population, subject to evaluation, is defined as any project receiving an upfront incentive on or before December 31, 2022. For generation technologies, project permanency is also considered.

4.2 PBI INTERVAL DATA

Projects receiving PBIs are required by the program to collect 15-minute interval metered performance data for a period of five years, in support of PBI payment processes. These data are stored in the SGIP Data Portal managed by Energy Solutions. For generation technologies, this data includes electrical generation, fuel consumption, and heat recovery. For energy storage projects, the data includes charge and discharge. Verdant downloaded, processed and performed quality control checks on all available PBI meter data.

4.3 MANUFACTURER AND PROJECT DEVELOPER DATA

Energy storage firms like Stem, ENGIE, Tesla, SunRun and others are a valuable source of data for the impact evaluation. Verdant issued data requests directly to equipment manufacturers or project developers to augment metered data collected from the statewide database to verify performance for energy storage and generation technologies. Some data received in response to these requests overlaps with information received from other sources such as electric utilities, the statewide project databases, or inspection reports. However, the evaluation team has learned that duplicate information from multiple sources creates powerful data validation opportunities. Data requests to energy storage firms included:

- Detailed system size parameters (inverter kW, battery kWh)
- Interval (15-minute or smaller) charge/discharge kWh data
- Interval (15-minute or smaller) customer load data
- Interval (15-minute or smaller) net generator output (NGO) data from any generation technologies co-located or paired with the storage system
  - If a generation technology is co-located, characteristics such as size (kW), and if solar PV, tilt and azimuth information
- Listing of the primary function or functions provided by the storage system (e.g., demand charge reduction, TOU arbitrage, absorbing excess renewable generation, backup)
- Listing of any demand response (DR), ancillary services, or other markets the system participates within
- Customer utility rate schedule for each month (billing period) throughout the year
- Where applicable, dates and times when the storage system delivered backup power to a customer due to a planned (Public Safety Power Shutoff (PSPS)) or unplanned outage.

Industry data requests were issued for most nonresidential systems and a sample of residential projects. This approach provides the ability to verify findings from two distinct data sources and make recommendations to the PAs when one data source is more reliable than another.

4.4 CUSTOMER AND PERFORMANCE DATA PROVIDER DATA

For many generation sites, the project either never took a PBI, or the PBI period has completed. While the data is not available to download directly, for many of these projects, the metering data will still be in place, and was accessible from the performance data provider (PDP) or the customer themselves. The Verdant team attempted to gather data from every generation project whose data was not available to download directly from Energy Solutions. The typical requested format was 15-minute interval data of electrical generation, fuel consumption (broken out by renewable gas and natural gas where possible), and heat recovered. In some cases, data may have been provided at the hourly, daily, or in a few cases, monthly aggregation levels. In other cases, electrical and fuel consumption data may have been available, but heat recovery data may not have been. SGIP participant responsibilities and commitments regarding delivery of metered performance data for M&E purposes are delineated in SGIP Handbooks and contracts. Verdant requested assistance from Program Administrators in obtaining metered data for M&E purposes in some cases.

4.5 PRIOR EVALUATION YEAR METERED DATA

Verdant has collected meter data for many years, and we incorporated these historical data into estimates of 2021-2022 impacts of unmetered projects using regression analyses, where enough data was available. More information about this can be found in Section 5.2.

4.6 ELECTRIC UTILITY DATA

Electric utilities are considered the most reliable source of customer load data and tariff information. Our approach to garnering utility data was staged throughout the evaluation. The first stage included all SGIP energy storage customers:

- Meter and service account information
- Customer utility rate schedule for each month (billing period) throughout the year
- Where applicable, dates and times when the storage system delivered backup power to a customer due to a planned (PSPS) or unplanned outage
- Listing of any demand response (DR), ancillary services, or other markets the system participates within

Once our team received these data, along with the requested data from the battery manufacturers and project developers, we issued an additional data request for customer load data from a sub-sample of the energy storage population and the entirety of the generation population. This request included:

- All customer interval kWh load data in the smallest interval that was collected (e.g. 15-minute, 1 hour) for the period spanning January 1, 2021, through December 31, 2022.
- Indication of treatment of daylight savings time and whether observations are period beginning or period ending.
- Unit of measure (kW, kWh, W, Wh).

- For bi-directional meters, flow direction (delivered vs. received).
- For storage systems paired with a renewable generator (such as solar PV) and utility owned Net Generator Output Meter (NGOM), all interval kWh generation from that meter in the smallest interval that was collected for the period spanning January 1, 2021, through December 31, 2022.

4.7 OPERATIONAL STATUS SURVEYS

Operational Status Research (OSR) surveys were used to fill data gaps for generation projects, targeting SGIP customers lacking large amounts of metered data. The survey sought to determine if periods without metered data fit into one of three categories:

- **Normal:** The system was online and operating normally during the period in question.
- **Off:** System did not generate electricity during the period in question but is still installed at the host site.
- **Decommissioned:** System has been physically removed from the host site and will never operate again.

Hosts that respond with an “Off” operational status have zero energy generation assigned during the time period in question. Similarly, hosts who respond with a decommissioned operational status have zeros added starting from the date the system was decommissioned through the remainder of the evaluation period. Missing observations will be estimated for generation projects whose operational status is “Normal” as well as projects with data gaps without operational status information.

5 SAMPLING PLANS AND DATA COLLECTION OUTCOMES

This section details the sampling approach used for the 2021-2022 SGIP impact evaluation. The sampling strategy was designed to provide statistically significant impacts while maintaining evaluation delivery timelines and project budgets. The sample design was informed by many of the program attributes discussed above in previous sections, and how they have changed and evolved over time.

5.1 SAMPLING PLANS

Sampling plans for energy storage and generation are described below. Different approaches were used for these two program elements due to material differences in their population sizes.

5.1.1 Energy Storage

For the energy storage population, the sample design was based on several factors: 1) the composition of the 2021-2022 population of SGIP storage projects, including budget category, payment year, service territory installation, project developer, equipment manufacturer, 2) availability of underlying data requirements, 3) understanding of historical data limitations, 4) results from the 2020 impact evaluation, 5) sampling requirements needed to develop population-level metrics with a high level of precision and 6) Decision 19-08-001 approved greenhouse gas emission reduction requirements.

Verdant employed a stratified random sampling approach, with an attempted census for some sectors for 2021-2022, given a careful review of the composition of the program, evaluation reporting deadlines, budgetary considerations, and results garnered from previous impact evaluations. To accomplish this, we examined a key design variable – greenhouse gas emissions – from the 2020 impact evaluation. We reviewed developer GHG emissions to better understand 1) the variation of average impacts across developers, 2) the variation of individual project impacts from the developer sample mean, 3) the relative precision of the sample estimate and 4) how many sample points we would need to evaluate in 2021-2022 to reach an estimate of GHG impacts at the project developer level with a high level of precision.

Figure 5-1 conveys how the relationship between sample size and coefficient of variation[23] (CV) affects resulting precision estimates at the 90% confidence level.[24] With a CV of 0.4, the evaluator could achieve

[23] The coefficient of variation is the standard deviation of a parameter divided by its mean.

[24] Khawaja, M. S.; Rushton, J.; Josh Keeling J. (April 2013). Chapter 11: Sample Design Cross-Cutting Protocols. The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures. NREL.

10% relative precision with 90% confidence with 50 sample points. As the variability in the estimate relative to the mean increases, much larger sample sizes are required to obtain a similar level of precision. With a CV of 1.0, sample sizes close to 300 are required to achieve 10% relative precision with 90% confidence.

FIGURE 5-1: RELATIVE PRECISION VERSUS SAMPLE SIZE AND COEFFICIENT OF VARIATION (90% CONFIDENCE)

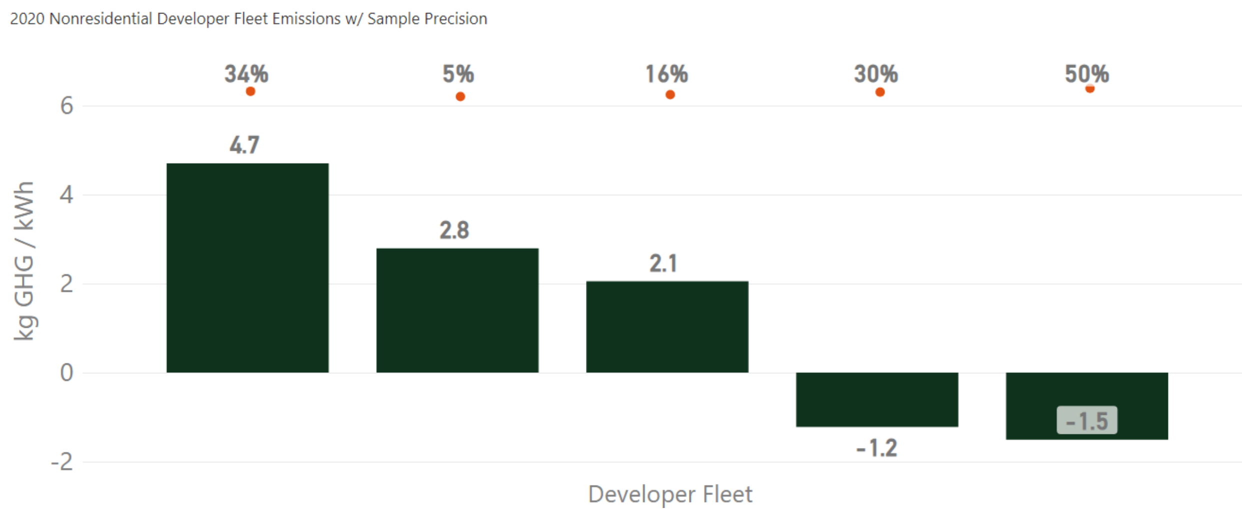
		CV											
		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2
Sample Size	5	7%	15%	22%	29%	37%	44%	51%	59%	66%	74%	81%	88%
	10	5%	10%	16%	21%	26%	31%	36%	42%	47%	52%	57%	62%
	20	4%	7%	11%	15%	18%	22%	26%	29%	33%	37%	40%	44%
	30	3%	6%	9%	12%	15%	18%	21%	24%	27%	30%	33%	36%
	50	2%	5%	7%	9%	12%	14%	16%	19%	21%	23%	26%	28%
	100	2%	3%	5%	7%	8%	10%	12%	13%	15%	16%	18%	20%
	150	1%	3%	4%	5%	7%	8%	9%	11%	12%	13%	15%	16%
	300	1%	2%	3%	4%	5%	6%	7%	8%	9%	9%	10%	11%
	500	1%	1%	2%	3%	4%	4%	5%	6%	7%	7%	8%	9%

Nonresidential Storage

To estimate sample size requirements, we analyzed GHG impacts estimates for the metered sample from the 2020 impact evaluation. Figure 5-2 presents those findings separately for each project developer in our nonresidential sample. Negative impacts (-) represent a *decrease* in kilograms of GHG emissions per incentivized capacity (kWh). The magnitude of GHG emissions impacts is displayed on the left vertical axis and the corresponding relative precision at the 90% confidence level is also provided above each bar. Each bar represents one of the five evaluated developers which constituted a developer fleet in the 2020 impact evaluation.

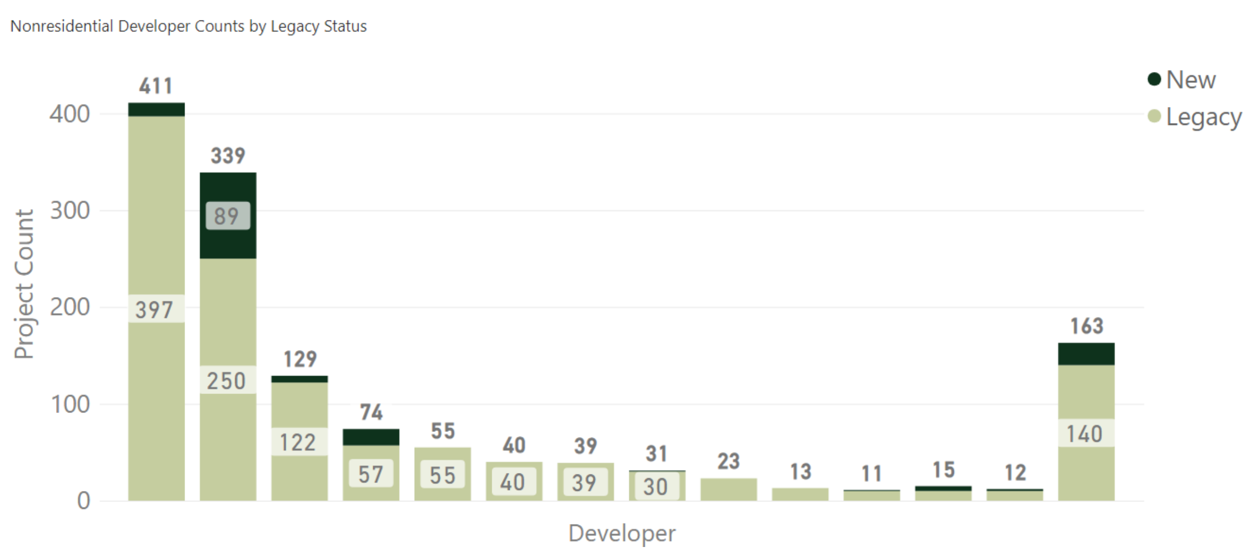
On average, GHG emissions impacts were positive for three developer fleets, and negative for two developers. There is significant variability in the sample mean estimate for each, and relative precision estimates ranged from 5% to 50% measured at the 90% confidence interval. The much greater CV estimates reveal nonresidential developers exhibited much greater inter-project variability than residential ones. This is by no means surprising given the much greater range in nonresidential storage capacities, the much more diverse use cases, and the less frequent pairing with on-site solar generation, compared to residential systems. This does suggest, however, that sample sizes are required to be greater – as a percentage of the population – for nonresidential developers.

FIGURE 5-2: GHG IMPACTS AND RELATIVE PRECISION BY NONRESIDENTIAL PROJECT DEVELOPER FLEET (2020)



Next, we reviewed the program tracking data to identify; 1) the unique number of project developers installing SGIP incentivized energy storage systems, 2) the number of unique *Legacy* projects each developer installed and 3) how many developers installed 10 *Legacy* projects or more (*developer fleet*). Figure 5-3 summarizes the developer fleets within the 2021-2022 population. While over 80 unique developers installed at least one SGIP *Legacy* project, with *Legacy* defined as any project completing their application prior to April 1, 2020, only 13 installed 10 or more systems. The non-fleet cohort of developers are combined in the bar to the far right of the exhibit.

FIGURE 5-3: COUNT OF LEGACY AND NEW NONRESIDENTIAL PROJECTS BY PROJECT DEVELOPER (2021-2022)

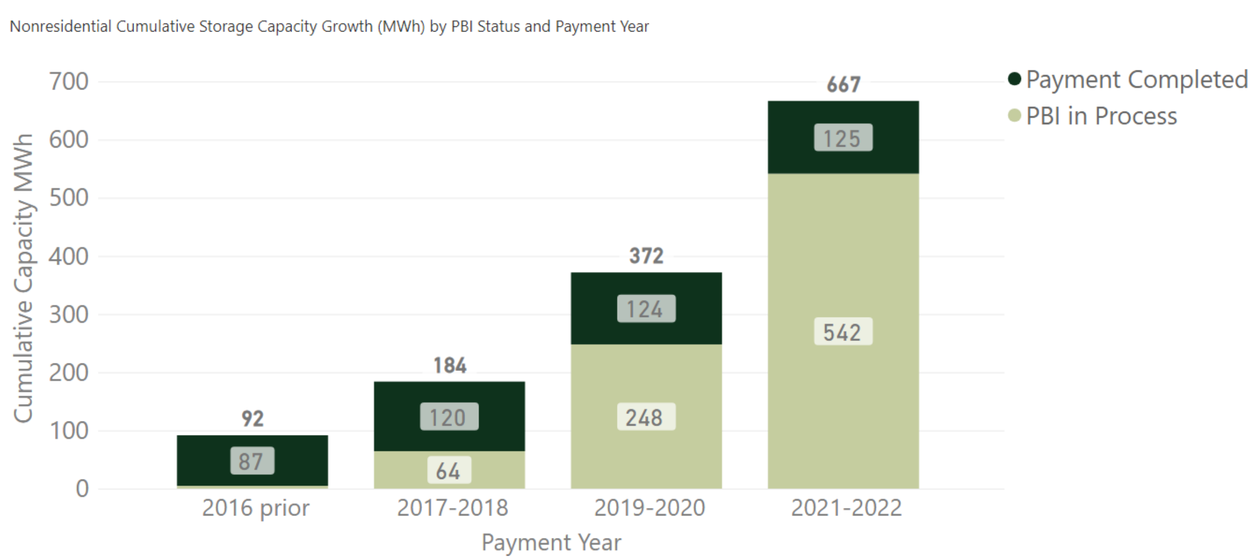


Those 13 unique developers constitute *developer fleets* and, as the program evaluator, Verdant is required to submit summary GHG emissions data for these fleets in the impact evaluation and track their program compliance pathways as set forth in D.19-08-001. The other developers, along with any other *New* projects, those completing applications on or after April 1, 2020 do not require developer reporting of GHG performance. However, these projects were incorporated into the sample design to better develop population level impact results for the overall program. The sample design was intended to enable us to:

- Estimate Legacy developer fleet GHG impacts at 90/30 or better. Given the high inter-project variability, we attempted a census for all developer PBI projects, and sampled non-PBI projects.
- Estimate population-level GHG impacts at the overall nonresidential sector level – along with other impact metrics like total avoided utility costs, coincident peak demand and roundtrip efficiency (RTE) – at 90/10 or better

One final design consideration for the nonresidential sector is PBI status. PBI projects have different utilization requirements depending on when they applied to the program and are larger than nonresidential systems not subject to performance incentives. The relative weight of these projects – in terms of overall program capacity and their contribution to overall program impacts – lends itself to careful consideration of them in the sample design. Figure 5-4 illustrates the capacity contribution of PBI project in 2021-2022. Of the total 667 MWh of nonresidential capacity, 542 MWh (81%) are for systems with a PBI payment in process.

FIGURE 5-4: NONRESIDENTIAL CUMULATIVE CAPACITY GROWTH BY PBI STATUS AND PAYMENT YEAR



The final nonresidential sample design accounts for 1) project vintage, 2) developer fleet designation, and 3) PBI status. All PBI projects are sampled, regardless of vintage, along with a sample of non-PBI Legacy projects. Table 5-1 presents the total count of projects within the nonresidential sample by PA.

TABLE 5-1: 2021-2022 PROPOSED SAMPLE DESIGN FOR NONRESIDENTIAL POPULATION

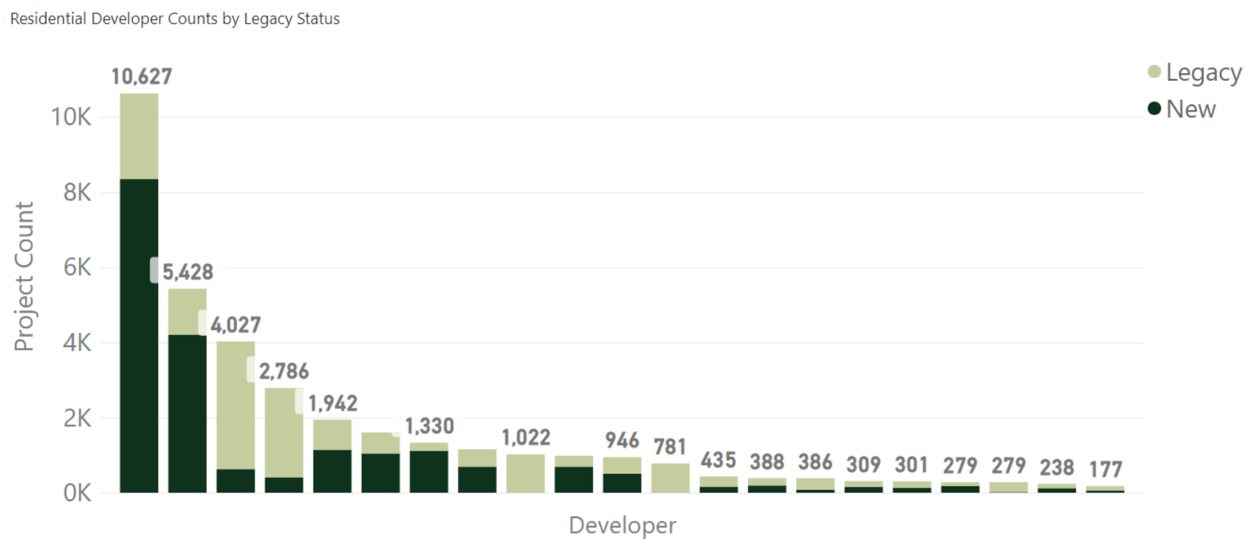
PA	Legacy	Fully Qualified State	Population	Developers	Legacy Developers	MWh Capacity
CSE	No	Payment PBI in Process	9	5	5	8
	Yes	Payment Completed	153	21	6	30
	Yes	Payment PBI in Process	105	16	7	57
PG&E	No	Payment PBI in Process	75	13	8	62
	Yes	Payment Completed	183	19	6	49
	Yes	Payment PBI in Process	168	26	8	95
SCE	No	Payment PBI in Process	71	14	6	70
	Yes	Payment Completed	180	18	7	44
	Yes	Payment PBI in Process	354	24	12	212
SCG	No	Payment PBI in Process	4	2	2	2
	Yes	Payment Completed	7	5	2	1
	Yes	Payment PBI in Process	46	5	5	36

*Included in this design are the five nonresidential thermal energy storage projects, all of which are PBI.

Residential Energy Storage

With over 35,000 residential projects subject to evaluation, represented by over 500 unique project developers, the residential sample design required a more thoughtful and robust stratified random sampling approach than the nonresidential sector. Figure 5-5 summarizes the distribution of residential project counts by developer and Legacy status (for ease of presentation, project developers with less than 100 completed Legacy projects have been combined under the first bar in the exhibit). Of the 10,627 projects in that combined category, over 80% constitute New projects. Some developers have a greater share of Legacy projects relative to New ones, but the distributions and overall counts are more variable than the nonresidential sector. The program has been dominated by two equipment manufacturers, but the market share of other manufacturers and developers has increased in the past few program years. Furthermore, changing budget categories, incentive levels, and installation costs have created a more dynamic program than the one previously studied in 2020.

FIGURE 5-5: COUNT OF LEGACY AND NEW RESIDENTIAL PROJECTS BY PROJECT DEVELOPER (2021-2022)

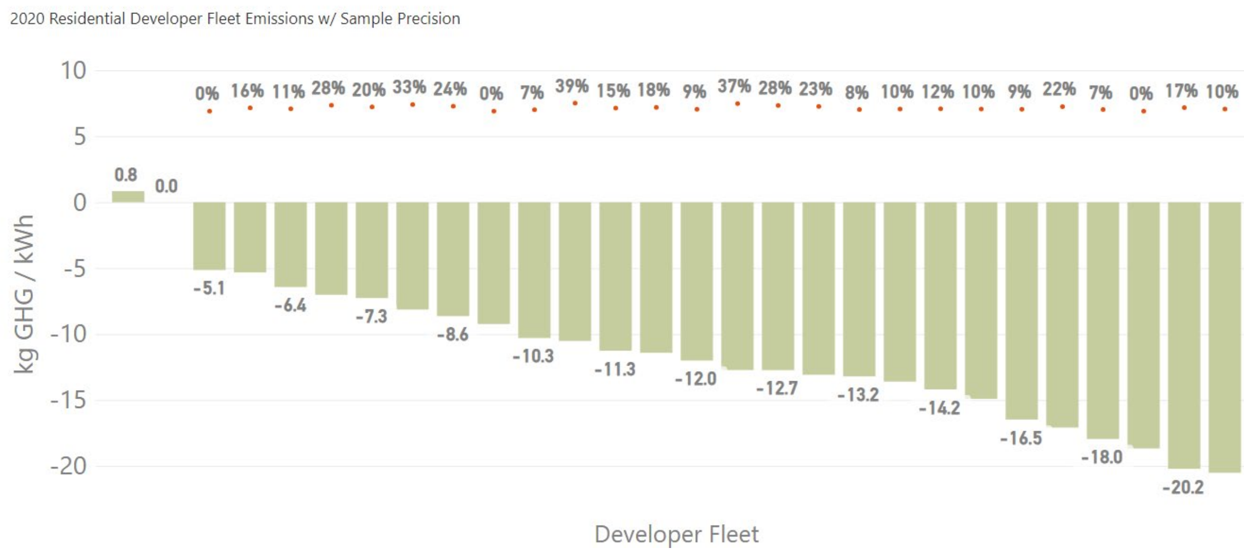


Much like the nonresidential sector, we analyzed the sample of residential projects from the 2020 impact evaluation and calculated GHG impacts for each project developer in the residential sample. While residential stratification for this 2021-2022 study is not constructed around developer, the exercise verifies some of the proposed sample targets required to reach population impacts at a high level of rigor and precision.

Figure 5-6 presents those results. Negative impacts (-) represent a *decrease* in kilograms of GHG emissions per incentivized capacity (kWh). The magnitude of GHG emissions impacts is displayed on the left vertical axis and the corresponding relative precision at the 90% confidence level is also provided. Each bar represents one of the thirty individual developers which constituted a developer fleet within the 2020 impact evaluation. GHG emissions impacts were negative for all but one developer[25], with reductions ranging from 5.1 kg/kWh to over 20 kg/kWh. The relative precision estimates ranged from 0% (where we evaluated all projects of a given developer) to 39% at the 90% confidence level. This means, despite inherent sampling error, varying sample sizes and a wide variety of individual storage use cases, we can say with a high level of certainty that almost all residential developers reduced emissions in 2020. The sample sizes and precision around those estimates helps drive the sample design for this study.

[25] We observed an increase of 0.8 kg/kWh for this developer. However, the relative precision around that estimate was 480% at the 90% confidence level.

FIGURE 5-6: GHG EMISSIONS IMPACTS AND RELATIVE PRECISION BY RESIDENTIAL PROJECT DEVELOPER (2020)



The residential sample design accounts for many of the program changes and trends discussed earlier and includes stratification by 1) two upfront payment year categories (2018-2020 and 2021-2022) to account for Legacy and New project designation, 2) equipment manufacturer, 3) program budget category, and 4) program administrator. In previous evaluations, we've observed measurable differences in performance and storage behavior across different product offerings, and other technologies have increased SGIP market share more recently since completion of the last impact evaluation for Calendar Year (CY) 2020. To account for those differences and to better represent technologies with unknown performance, battery manufacturer is an important stratification variable. Technologies which have been evaluated in the past were further stratified by payment year grouping, so results from this evaluation can be better compared to past evaluations, and to account for more recent installations as well. Table 5-2 presents the sample design for the residential sector. The table includes PA, budget category, and payment year stratification – manufacturer and developer considerations are built into these sample targets.

There are also roughly 2,150 projects we did not include in the impacts evaluation. These projects represent either 1) two residential project developers who went bankrupt and where Verdant has not successfully collected metered data from their systems in the past (~1,700 projects) or 2) projects receiving incentives before 2018 and their data acquisition systems are antiquated and metered data cannot be accessed (~450). These sample sizes also consider developer GHG impacts at 30% relative precision or better with 90% confidence (90/30) and 90/10 or better at the customer sector level. Furthermore, attrition rates from previous evaluations range from 10% to 20% depending on the performance data provider, so expected sample targets consider these real-world challenges.

TABLE 5-2: 2021-2022 SAMPLE DESIGN FOR RESIDENTIAL POPULATION

PA	Budget Category	Payment Year	Population	Proposed Sample	% Population Sampled
CSE	Equity Resiliency	2018-2020	52	52	100%
		2021-2022	1,107	126	11%
	Large-Scale Storage	2018-2020	31	4	13%
		2021-2022	151	16	11%
	Small Residential Storage	2018-2020	1,850	182	10%
		2021-2022	2,051	211	10%
	CSE All		**5,242**	**591**	**11%**
PG&E	Equity Resiliency	2018-2020	80	80	100%
		2021-2022	3,935	481	12%
	Large-Scale Storage	2018-2020	141	16	11%
		2021-2022	798	109	14%
	Residential Storage Equity	2021-2022	3	3	100%
	San Joaquin Valley	2021-2022	57	57	100%
	Small Residential Storage	2018-2020	4,453	409	9%
		2021-2022	7,104	1,002	14%
	PG&E All		**16,571**	**2,157**	**13%**
SCE	Equity Resiliency	2018-2020	30	30	100%
		2021-2022	1,735	232	13%
	Large-Scale Storage	2018-2020	25	2	8%
		2021-2022	218	29	13%
	Residential Storage Equity	2021-2022	9	9	100%
	Small Residential Storage	2018-2020	4,349	393	9%
		2021-2022	2,866	394	14%
	SCE All		**9,232**	**1,089**	**12%**
SCG	Equity Resiliency	2018-2020	5	5	100%
		2021-2022	369	46	12%
	Large-Scale Storage	2018-2020	43	4	9%
		2021-2022	80	9	11%
	Residential Storage Equity	2021-2022	1	1	100%
	Small Residential Storage	2018-2020	835	80	10%
		2021-2022	736	123	17%
	SCG All		**2,069**	**268**	**13%**
All			***33,114***	***4,105***	***12%***

5.1.2 Generation

For the generation population, the approach was simple; due to the small size of the generation population in comparison to the overall program, the evaluation team attempted a census of the generation population. The first step was to download metered data for all projects still receiving PBI payment, from the Energy Solutions portal. For the remaining projects with no PBI data, the team reached out to every customer or project developer to request either metered performance data during 2021 and 2022, or in the absence of the data, to attempt to understand whether the system was performing normally, had major downtimes, was offline completely, or was decommissioned and removed from the facility.

5.2 DATA COLLECTION OUTCOMES

This section summarizes the sampled projects for which data were collected as part of this evaluation, for energy storage and generation projects separately.

Energy Storage

Data processing and validation steps were performed on all metered data Verdant received as part of this impact evaluation. Sample sizes were developed to ensure SGIP population impacts were estimated at high levels of confidence and precision, and with an understanding that metering data acquisition systems are not perfect. Data attrition occurs when Verdant receives unverifiable metered data – either from partial or wholly missing metered values or data anomalies that one would not expect from energy storage performance (an example of this is a project roundtrip efficiency of greater than 100%). This section summarizes the sample design discussed previously and presents the final achieved sample for each of the energy storage customer sectors after a rigorous QA/QC process was completed.

Table 5-3 presents the population and achieved sample design for the nonresidential sector. Each is presented by project Legacy status and fully qualified state, for the four PAs, as well as at the statewide level. While there is inter-segment variability, achieved sample sizes range from 78% to 87% by project count. Overall, data were collected and analyzed for 1,125 nonresidential projects (83% of all nonresidential projects in the population) for either CY 2021, 2022, or both. The achieved sample is even greater as a percentage of program capacity. Achieved sample sizes range from 89% to 97% by program capacity – with 90% of the MWh of the nonresidential program represented.

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TABLE 5-3: 2021-2022 ACHIEVED SAMPLE DESIGN FOR NONRESIDENTIAL POPULATION

PA	Legacy	Fully Qualified State	Pop	Sample	Sample % of Pop	Pop MWh	Sample MWh	Sample % of Pop MWh
CSE	No	Payment PBI in Process	9	9	100%	8	8	100%
	Yes	Payment Completed	153	108	71%	30	23	75%
	Yes	Payment PBI in Process	105	92	88%	57	55	96%
	CSE All		**267**	**209**	**78%**	**95**	**86**	**90%**
PG&E	No	Payment PBI in Process	75	71	95%	62	60	97%
	Yes	Payment Completed	183	123	67%	49	38	78%
	Yes	Payment PBI in Process	168	150	89%	95	85	90%
	PG&E All		**426**	**344**	**81%**	**206**	**184**	**89%**
SCE	No	Payment PBI in Process	71	56	79%	70	60	85%
	Yes	Payment Completed	180	138	77%	44	39	89%
	Yes	Payment PBI in Process	354	330	93%	212	196	92%
	SCE All		**605**	**524**	**87%**	**326**	**295**	**90%**
SCG	No	Payment PBI in Process	4	1	25%	2	1	73%
	Yes	Payment Completed	7	3	43%	1	1	90%
	Yes	Payment PBI in Process	46	44	96%	36	35	98%
	SCG All		**57**	**48**	**84%**	**39**	**38**	**97%**
All			***1,355***	***1,125***	***83%***	***667***	***602***	***90%***

Table 5-4 provides the achieved sample design for the residential sector. Population, sample targets, and achieved samples are presented for PAs by budget category and upfront payment year, along with a statewide total. While there is inter-segment variability, achieved sample sizes range from 59% to 76% by project count. Overall, data were collected for 3,045 residential projects (9% of all residential projects in the population and 74% of the total sample target) for either CY 2021, 2022, or both. The achieved sample is even greater as a percentage of program capacity.

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TABLE 5-4: 2021-2022 ACHIEVED SAMPLE DESIGN FOR RESIDENTIAL POPULATION

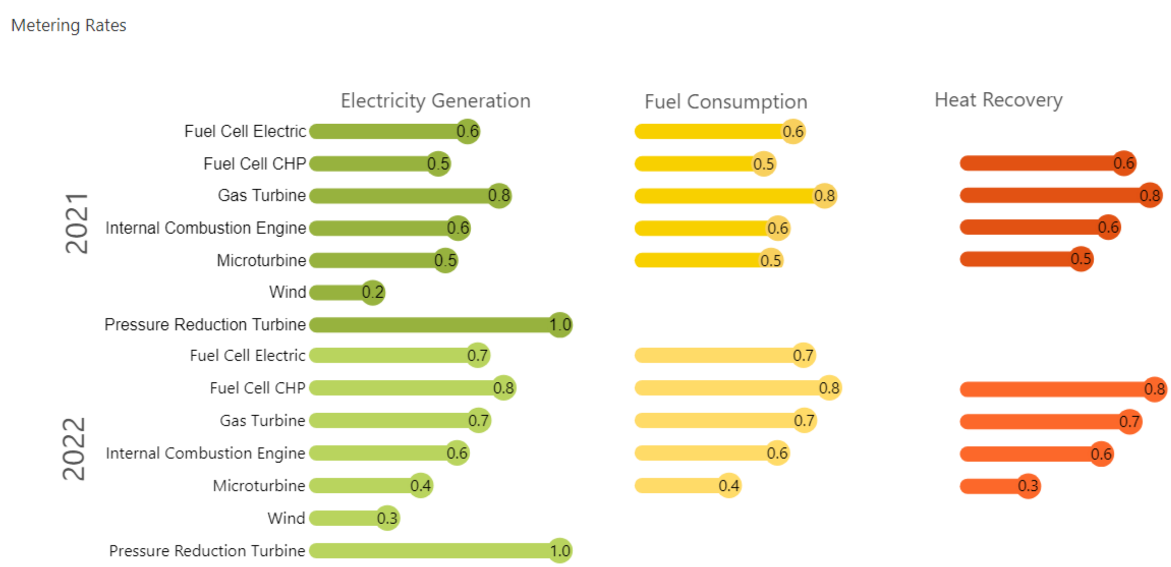
PA	Budget Category	Payment Year	Pop	Sample Target	Sample Achieved	% Smp Achieved	% Smp Achieved of Pop
CSE	Equity Resiliency	2018-2020	52	52	1	2%	2%
		2021-2022	1,107	126	99	79%	9%
	Large-Scale Storage	2018-2020	31	4	4	100%	13%
		2021-2022	151	16	12	75%	8%
	Small Residential Storage	2018-2020	1,850	182	145	80%	8%
		2021-2022	2,051	211	158	75%	8%
	CSE All		**5,242**	**591**	**419**	**71%**	**8%**
PG&E	Equity Resiliency	2018-2020	80	80	35	44%	44%
		2021-2022	3,935	481	338	70%	9%
	Large-Scale Storage	2018-2020	141	16	12	75%	9%
		2021-2022	798	109	74	68%	9%
	Residential Storage Equity	2021-2022	3	3	1	33%	33%
	San Joaquin Valley	2021-2022	57	57	51	89%	89%
	Small Residential Storage	2018-2020	4,453	409	399	98%	9%
		2021-2022	7,104	1,002	733	73%	10%
	PG&E All		**16,571**	**2,157**	**1,643**	**76%**	**10%**
SCE	Equity Resiliency	2018-2020	30	30	3	10%	10%
		2021-2022	1,735	232	155	67%	9%
	Large-Scale Storage	2018-2020	25	2	2	100%	8%
		2021-2022	218	29	19	66%	9%
	Residential Storage Equity	2021-2022	9	9	1	11%	11%
	Small Residential Storage	2018-2020	4,349	393	357	91%	8%
		2021-2022	2,866	394	287	73%	10%
	SCE All		**9,232**	**1,089**	**824**	**76%**	**9%**
SCG	Equity Resiliency	2018-2020	5	5	3	60%	60%
		2021-2022	369	46	24	52%	7%
	Large-Scale Storage	2018-2020	43	4	5	125%	12%
		2021-2022	80	9	6	67%	8%
	Residential Storage Equity	2021-2022	1	1		0%	0%
	Small Residential Storage	2018-2020	835	80	70	88%	8%
		2021-2022	736	123	51	41%	7%
	SCG All		**2,069**	**268**	**159**	**59%**	**8%**
All			***33,114***	***4,105***	***3,045***	***74%***	***9%***

VERDANT

Generation

Metering rates for generation equipment, for each of the different data types (electrical generation, fuel consumption, and heat recovery) are provided below in Figure 5-7. The metering rate is defined as the number of hours for each project during the year with metered data divided by the total number of hours per year that the equipment is within its permanency period. For example, if a project exited its permanency period halfway through the year, the total number of hours for that project would reflect the date it was no longer within its permanency period. These metering rates are unweighted and do not reflect the relative importance of metering large projects. They are based only on projects that are still operational. More about decommissioned projects can be found in Section 6.

FIGURE 5-7: GENERATION METERING RATES



For generation projects, missing values (either due to gaps in metered data or unavailable project data) are estimated using the findings from previous operations status surveys, ratio estimation, and adjustment using results of regression analysis of historical data.

The estimation approach used for fuel cell electric, fuel cell CHP, and wind turbines was dictated largely by the fact that meter data for older projects and smaller projects taking capacity-based incentives was much harder to gather than data for newer and larger projects. However, our team has been evaluating this program since its inception, and metered data collected during prior evaluations was available for many older projects. To estimate 2021-2022 impacts for unmetered fuel cells and wind turbines, 2021-2022 metered data available for PBI projects were used in a ratio analysis to estimate initial impact estimates. Results from the regression analysis of historical metered data were used to develop Age (A) and Incentive Design (I) adjustment factors for older PBI and non-PBI projects. The general approach is represented by the equation below.

$$Final\ Estimate = Ratio\ Estimate \times I \times A \qquad \textbf{EQUATION 5-1}$$

Regression analysis of metered data collected for past years was used to develop adjustment factors that were applied to initial impact estimates from the ratio analysis. The ratio analysis was performed using metered 2021-2022 data for PBI projects. The purpose of the adjustment factors was to account for systematic performance differences due to system age (A) and incentive design (I) when estimating 2021-2022 impacts for unmetered fuel cell and wind turbine projects.

For each technology type, the regression analysis yields a prediction model for annual capacity factor of the general form:

$$\widehat{CF} = \widehat{\beta_0} + \widehat{\beta_1}age + \widehat{\beta_2}incentive \qquad \textbf{EQUATION 5-2}$$

Where:

$\widehat{CF}$	=	predicted annual capacity factor
age	=	age of system in years
$incentive$	=	indicator variable equal to 1 when incentive design is non-PBI, 0 otherwise

The regression models were used to calculate system age (A) and incentive design (I) adjustment factors for each unmetered system as:

$$A = \frac{Predicted\ CF\ for\ older\ system\ (e.g., 7\ years)}{\begin{array}{c}Predicted\ CF\ for\ system\ with\ age\\ corresponding\ to\ initial\ impacts\ estimates\end{array}} \qquad \textbf{EQUATION 5-3}$$

$$I = \frac{Predicted\ CF\ for\ non-PBI\ system}{\begin{array}{c}Predicted\ CF\ for\ system\ with\ incentive\ design\ (i.e., PBI)\\ corresponding\ to\ initial\ impacts\ estimates\end{array}} \qquad \textbf{EQUATION 5-4}$$

Ratio estimation was used to calculate initial estimates of hourly performance for periods where observations would otherwise contain missing values. The premise of ratio estimation is that the performance of unmetered projects (projects outside the sample or projects in the sample with gaps in metered data) can be estimated from projects with metered data using a ratio estimator and an auxiliary variable. The ratio estimator is calculated from the metered sample and the auxiliary variable is used to apply the estimator to the unmetered portion of the backbone. Table 5-5 summarizes the characteristics of the ratio estimation.

TABLE 5-5: RATIO ESTIMATION PARAMETERS

Variable Estimated	Ratio Estimator	Auxiliary Variable	Stratification
Electricity Generation [kWh]	Capacity Factor [kWh/kW·hr]	Rebated Capacity [kW]	Hourly, by tech. type, incentive, size category, fuel type, and PA.
Fuel Consumption [MBtu]	Electrical Conversion Efficiency [unitless]	Electricity Generation [kWh]	Annual, by technology
Useful Heat Recovered [MBtu]	Useful Heat Recovery Rate [MBtu/kWh]	Electricity Generation [kWh]	Annual, by technology

The outcome of the ratio estimation process is a complete hourly impacts time series for 2021 and 2022 where meter data gaps are filled with initial estimates of electricity generation, fuel consumption, and useful heat recovery. To calculate final estimates for fuel cells and wind turbines, these initial estimates were adjusted as described above.

6 SGIP PERFORMANCE METRICS AND IMPACTS

The primary objective of this study is to evaluate energy, environmental, and financial impacts of generation systems and energy storage systems rebated through the Self-Generation Incentive Program (SGIP) and operating during calendar years 2021-2022. Impacts estimates for all projects in the population - metered as well as unmetered - are presented in Section 6.8. Results of analysis of metered data only are presented in Sections 6.1 through 6.6. Energy storage optimization results are presented in Section 6.7.

In the calculation of program impacts, two important issues arise: 1) definition of counterfactual baselines, and 2) treatment of decommissioned projects. The approach used for each of these issues is described below.

Counterfactual Baselines Used in Impacts Calculations

Some of the results discussed in this report are developed to better understand the efficiency of SGIP systems or how well utilized they are throughout the year. These performance metrics, such as the RTE, ECE or CF, can be calculated using only data collected for SGIP system inputs and outputs. Calculation of impacts, such as change in coincident peak electricity demand measured at the utility meter, requires assumptions about what a customer's electricity consumption at the meter would have been had they *not* installed the SGIP system. These assumptions describe an unobservable counterfactual non-SGIP baseline that is compared to electricity consumption observed to estimate impacts of the SGIP system at the utility meter as:

$$Impacts = UtilityMeterLoad_{with\ SGIP\ system} - UtilityMeterLoad_{counterfactual}$$

EQUATION 6-1

For this impacts evaluation, the keystone assumption underlying the impacts analytic methodology is that participation in the SGIP was not responsible for any changes in the quantity or timing of electricity loads for end uses *LoadsEndUses* (e.g., lighting, HVAC) that might have occurred after installation of the SGIP system, or for any changes in the quantity or timing of electricity production *PV* of any photovoltaic system capacity that might be present. The values of *LoadsEndUses* and *PV* are thus identical for the counterfactual and for the observed conditions (with SGIP system). That is:

$$UtilityMeterLoad_{counterfactual} = LoadsEndUses - PV$$ **EQUATION 6-2**

and

$$UtilityMeterLoad_{with\ SGIP\ system} = LoadsEndUses - PV - SGIPengo$$ **EQUATION 6-3**

Substituting into the equation for impacts:

$$Impacts = (LoadsEndUses - PV - SGIPengo) - (LoadsEndUses - PV)) = -SGIPengo$$ **EQUATION 6-4**

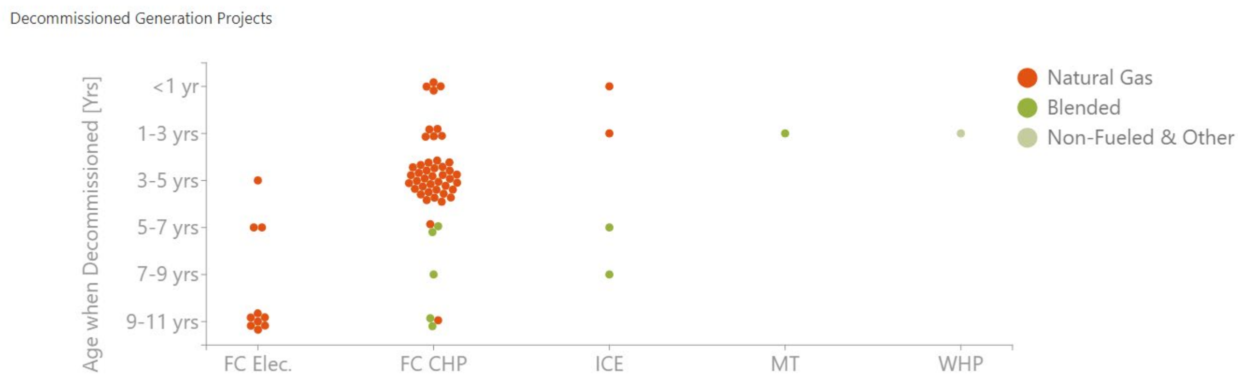
That is, the impacts of the SGIP system on coincident peak electricity consumption measured at the utility meter are simply equal to the negative of SGIP system output. This is an intuitive result describing the situation where SGIP system power output serves to decrease the amount of utility power required to satisfy end use loads. Where SGIPengo is defined as SGIP system power output, as it is above, battery energy storage systems would have negative SGIPengo values while charging, resulting in positive impacts (i.e., increased load at the utility meter) when charging.

Decommissioned and Off-line Projects

Our team has identified, throughout the past several evaluation cycles, systems that are offline or have been decommissioned. Decommissioned systems are not included in the assessments of Observed Performance Metrics and Observed Impacts; however, their non-performance is captured when developing program population impacts estimates.

Out of the generation population, 65 projects were found to be decommissioned prior to the end of their permanency period. Decommissioned projects represent approximately 13% of the population. Figure 6-1 highlights the number of projects by equipment type, fuel type, and age at which they were decommissioned. There were several CHP fuel cells by a single manufacturer with problems, and several of them returned their incentives and were noted as “recalled” in the program tracking data. However, there were many more which were not marked as recalled, which are depicted in the figure below. Of the other technologies, all electric fuel cells were generally close to the end of their permanency period before they were removed. A few other projects hadn’t even completed their PBI payment period before they were decommissioned.

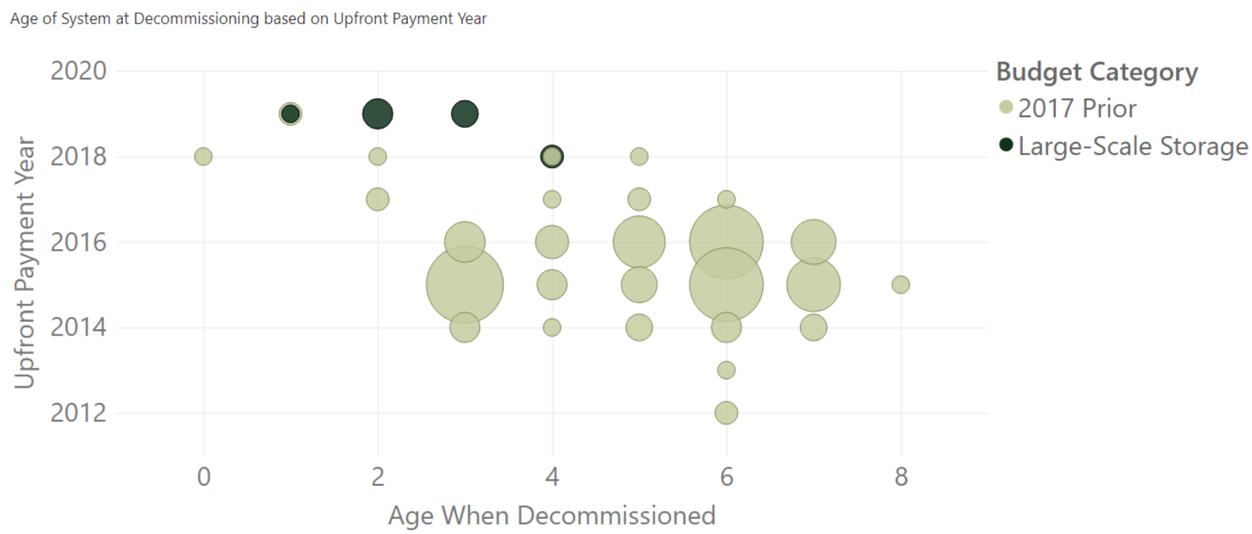
FIGURE 6-1: DECOMISSIONED GENERATION PROJECTS[26]



Many of the energy storage systems determined to be decommissioned or offline applied to the SGIP and received their upfront incentive payment during early program years. In the case of one developer, all their systems have been removed or remain offline after a bankruptcy filing. For the 2020 impact evaluation, Verdant had identified a total of 73 nonresidential systems that were offline or were decommissioned prior to or during 2020. This total has grown to 196 – with 123 systems decommissioned in 2021 or 2022. Decommissioned projects represent roughly 14% of all nonresidential systems in the population, but only 2% of capacity. Figure 6-2 presents the average age of decommissioned systems versus year in which initial upfront incentive payment was made. The size of the bubble corresponds to the count of systems, with the smallest bubbles representing one project and the largest representing 33 projects.

[26] Permanency periods vary both by technology and by program year. Fuel Cells, Pressure Reduction Turbines, Waste Heat to Power, Wind Turbines with an application year prior to 2013, all have 10 year permanency period requirements. Similarly, Gas Turbines and Internal Combustion Engines and Microturbines with an application year of 2011 or later all have 10 year permanency period requirements, yet those same systems with older application years had 6 year permanency period requirements. Wind turbines with application years 2013 or later have 20 year permanency period requirements.

FIGURE 6-2: DECOMISSIONED ENERGY STORAGE PROJECTS



When developing the research plan and sample design for this study, Verdant flagged nonresidential projects which have been decommissioned since completion of the most recent 2020 study and combined them with those identified from previous studies. The forthcoming analyses on observed storage performance exclude the impacts from these projects. These systems are no longer installed and operable, so their non-performance is known and would misrepresent the impacts generated from SGIP storage systems which are currently installed and operable. However, given the cumulative nature of these evaluations, their non-performance is combined with those that are still operational to develop program population impacts. Furthermore, given the negative consequences of decommissioning, Verdant plans to conduct interviews with a sample of host customers and project developers for the 2023 Impact Evaluation to better understand why systems were removed while they may have been still operable.

6.1 OBSERVED PERFORMANCE METRICS

The effectiveness of generation systems and energy storage systems in producing impacts depends largely on energy conversion efficiencies and operational choices governing equipment utilization. Metered data were analyzed to develop measures of efficiencies and utilization of SGIP systems operating during 2021-2022. Overall system efficiencies depend on the combined effects of efficiencies of many subsystems. For example, gas turbine generator system efficiency depends on fuel combustion efficiency, electric generator efficiency, and numerous other component efficiencies. Battery energy storage system efficiency depends on electro-chemical efficiencies associated with charge/discharge cycles, voltage transformation efficiencies and numerous other component efficiencies. However, overall system efficiencies are of interest to end users, and are the efficiencies we present results for in this section.

The general term 'utilization' summarizes the combined effects of various factors governing how much an SGIP system is used, which is closely related to the impacts it can produce. Utilization may encompass matters of choice (e.g., operating hours, operating mode selection), as well as resource availability in the case of wind turbine systems. Capacity factor is one performance metric customarily used to measure utilization. Capacity factors are calculated as the ratio of system energy output during any particular period of time to the maximum possible quantity of energy the system could have output during that period of time. Capacity factors for generation systems and energy storage systems are presented below. A second utilization metric is used for battery energy storage: charge/discharge cycle rate, with the total number of cycles per year being of most interest.

6.1.1 Energy Storage Performance Metrics

Verdant reviewed three performance metrics within the SGIP –roundtrip efficiency (RTE), capacity factor (CF) and annual energy storage cycling – to better quantify the efficiency and utilization of energy storage technologies throughout 2021-2022. We also reviewed if systems increased or decreased their utilization and efficiency over time by examining how storage performance changed for projects operating in both 2021 and 2022. Furthermore, we present if and how efficiencies and utilization differ based on the age of the system, system capacity, budget category, facility type (for nonresidential installations), and presence of on-site solar PV generation.

Energy Storage Efficiency

Roundtrip efficiency (RTE) is measured as the total kWh discharge of the system divided by the total kWh charge and is an eligibility requirement for the SGIP.[27] The RTE can be calculated as a single-cycle RTE, which captures the energy losses associated with AC-DC power conversion, and over a given time to also capture operational parasitic loads. This evaluation quantifies the latter, where efficiency is calculated for each system over the whole period for which dispatch data were available and deemed verifiable.

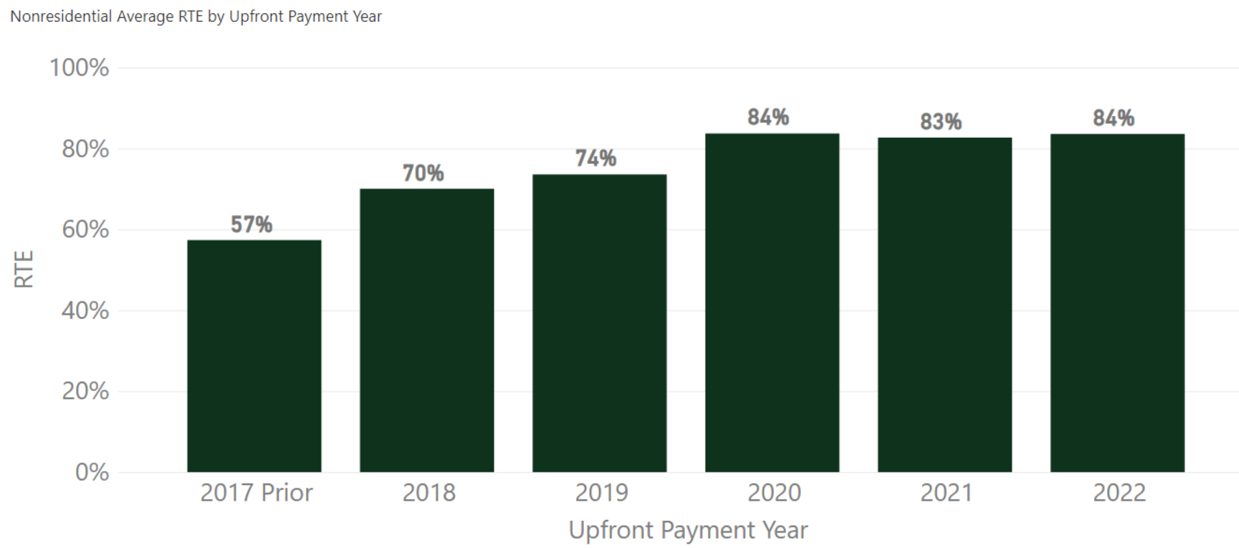
$$Roundtrip\ Efficiency = \frac{\sum kWh\ Discharge\ (kWh)}{\sum kWh\ Charge\ (kWh)} \qquad \textbf{EQUATION 6-5}$$

Figure 6-3 presents the average RTE for installed and operable nonresidential systems in 2022 by upfront payment year. We observe an average RTE of 57% in 2022 for projects receiving their upfront incentive

[27] Energy storage systems must maintain a round trip efficiency equal to or greater than 69.6% in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5 percent, assuming a 1% annual degradation rate (Appendix E of the aforementioned SGIP Handbook).

payment in 2017 and prior. We observe a trend in increased efficiency for systems rebated more recently – with systems receiving incentives in 2021 and 2022 exhibiting an RTE of 83-84% on average.

FIGURE 6-3: AVERAGE 2022 RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



We also examined the distribution of project specific RTEs by developing boxplots across incentive payment year. These boxplots present the mean RTE (red circle) along with the minimum, maximum, and median values. We observe not only increases in average and median RTE values with more recently incentivized projects, but less variation in project RTEs as well. For four of the six vintages the minimum 2022 RTE observed was 0%. An RTE of 0% signifies that the system was non-operational and the total 2022 discharge was 0 kWh. Verdant verified the performance of each project as part of the QA/QC process, and the metered data for systems exhibiting low or a zero RTE confirm this non-performance. Most of these non-operational systems applied to the program in earlier years (2012-2016) and represent a developer experiencing more recent decommissioning. Verdant will continue to track these projects in future evaluations to determine if systems were off-line or non-operational just for a given time, or if the non-performance is a harbinger for future decommissioning.

FIGURE 6-4: DISTRIBUTION OF 2022 RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

Residential RTEs exhibit less variability across project and payment year. Efficiencies range from 77% for projects recently incentivized in 2022 and 84% for projects incentivized in 2021. Unlike the nonresidential sector, all sampled residential projects applied to the program in 2017 or after and received their upfront payments in 2018 or thereafter. Boxplots in Figure 6-6 confirm both high average efficiency in the residential sector along with the narrow spread in project specific RTEs. Verdant did observe some low and non-operational systems within the sample of projects. This non-performance suggests these systems were operating in exclusive backup mode. Roughly 4% of sampled residential systems were found to be under-utilized or in backup mode during 2022.

FIGURE 6-5: AVERAGE 2022 RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

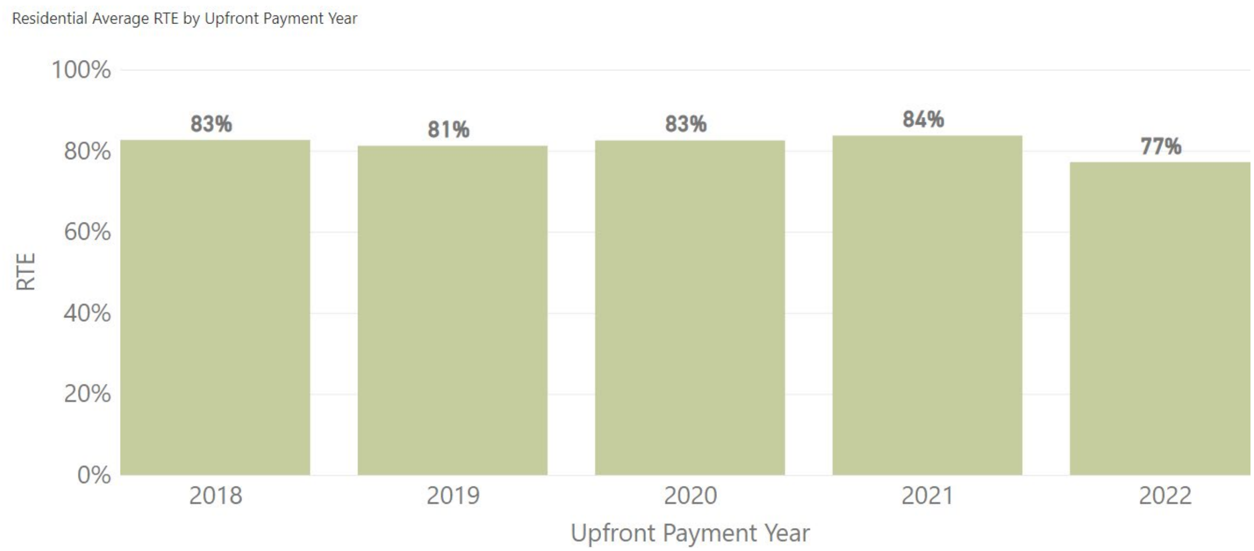
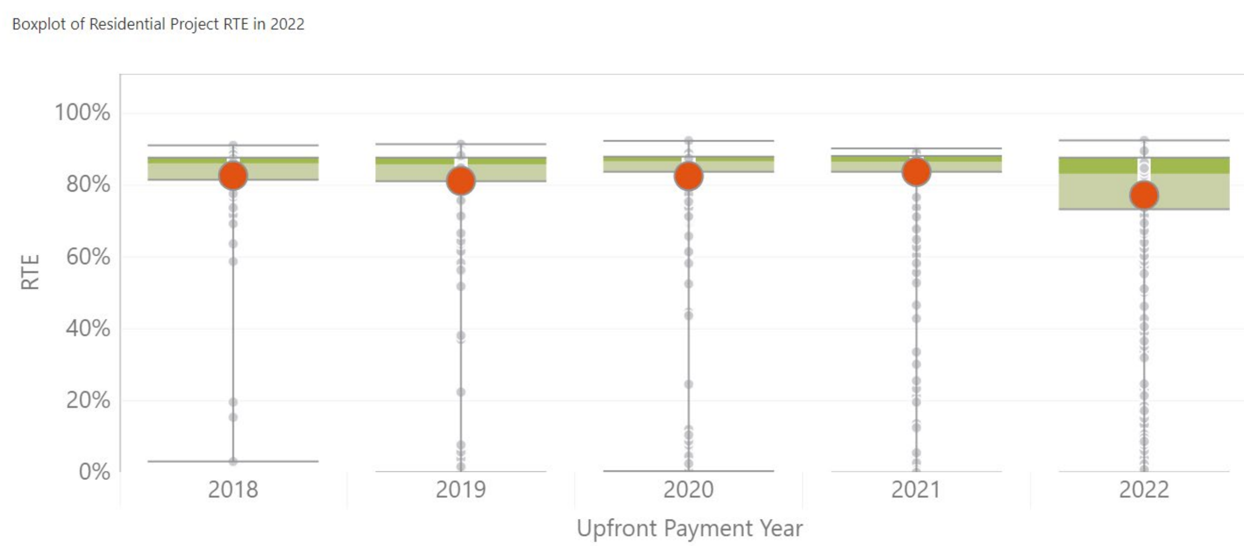


FIGURE 6-6: DISTRIBUTION OF 2022 RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Energy Storage Utilization

Energy storage utilization is marked by two performance indicators – CF and cycling. Capacity factor was defined above – as the sum of the storage discharge (in kWh) divided by the maximum possible discharge throughout a given period. Unlike generating technologies like a fuel cell which can operate at or near full capacity nearly continuously, storage discharge is limited by the size of the inverter and the kWh capacity of the battery along with the battery state-of-charge (SOC). Example CFs are provided in Figure 6-7 to better understand utilization as a function of discharge capacity – in percent power discharge over the course of an hour – and battery duration. In practice, a five-hour battery discharging at 100% discharge capacity once a day would have a 21% capacity factor. Most nonresidential storage systems are two-hour batteries, and some newer installations, especially critical services facilities in the ERB, are four to six-hour duration batteries. Residential systems are generally two to three-hour batteries.

FIGURE 6-7: CAPACITY FACTOR BY SYSTEM DURATION AND % KW HOURLY DISCHARGE

Capacity Factor by System Duration and % kW Hourly Discharge

kW Discharge	1 hr	2 hrs	3 hrs	4 hrs	5 hrs
10%	0%	1%	1%	2%	2%
20%	1%	2%	3%	3%	4%
40%	2%	3%	5%	7%	8%
60%	3%	5%	8%	10%	13%
80%	3%	7%	10%	13%	17%
100%	4%	8%	13%	17%	21%

Hourly discharge capacity is also predicated on the underlying storage operating mode – TOU arbitrage (with or without export), demand charge reduction, or (solar) self-consumption. If a battery is programmed for self-consumption – zeroing out both exported generation and imported load as much as possible – battery discharge is limited to underlying BTM consumption and may represent only a fraction of system capacity within a given hour. On the other hand, TOU optimization may result in daily cycling during the four summer months (June-September) but none during the other eight months of the year, due to low peak to off-peak rate differentials.

The capacity factors for the sample of nonresidential storage systems are presented below in Figure 6-8 by upfront payment year. To better understand the range in system utilization throughout the year, boxplots also follow in Figure 6-9. Capacity factors are positively correlated to RTEs – an under-utilized storage system will generally exhibit a low RTE and greater utilization signals greater system efficiency. Capacity factors range from as low as 0% (indicating non-performance) to as high as 19%.

FIGURE 6-8: AVERAGE 2022 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

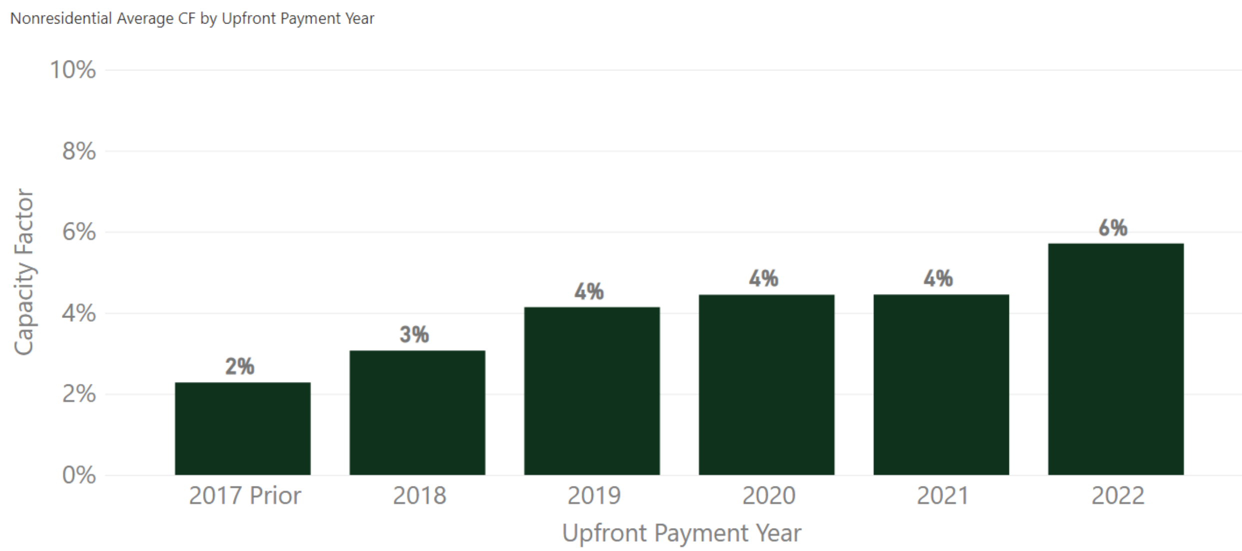
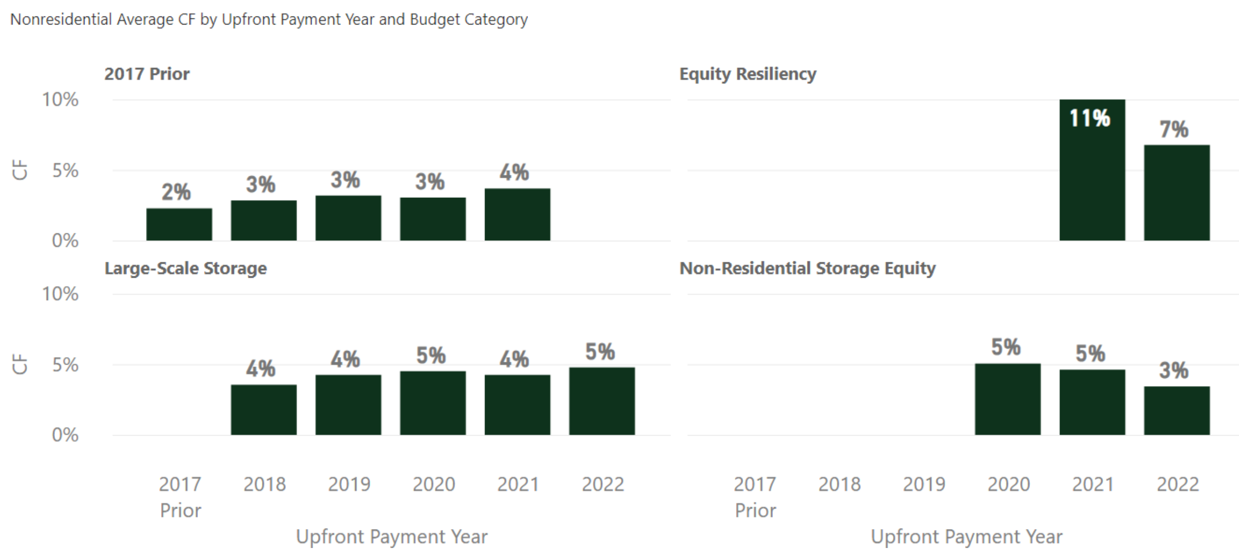


FIGURE 6-9: DISTRIBUTION OF 2022 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

The average CF ranges from 2% for projects receiving incentive in 2017 and prior to as high as 6% for projects receiving incentives in 2022. While we observe a general increase in utilization for projects incentivized more recently, an additional contributor to utilization gains is battery kWh capacity and system duration. Systems incentivized through the ERB are generally larger and longer duration (4-6 hours) than other nonresidential systems. Projects receiving incentives in this category provide resiliency and critical services to communities and are installed in facilities – like wastewater treatment plants – which may require more resiliency protection in the event of an outage. Longer duration batteries can exhibit greater capacity factors than shorter duration batteries (all else being equal). Figure 6-10 below details that further. Systems receiving upfront payments in 2021 and 2022 exhibited CFs of 11% and 7%, respectively in 2022.

FIGURE 6-10: 2022 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY PAYMENT YEAR AND BUDGET CATEGORY



Average capacity factors and CF distributions in the residential sector are presented below in Figure 6-11 and Figure 6-12. Residential capacity factors don't exhibit much variability across payment year, but we do observe inter-project variability. Residential systems are generally operating in one of two modes – TOU arbitrage or self-consumption. For systems operating in either mode (and are not exporting), discharge is limited to underlying customer load. For TOU arbitrage, the battery will generally discharge only during the customer on-bill peak period to zero out utility imports. Once the battery reaches a minimum state-of-charge (SOC) the battery will stop discharging. Self-consumption is a similar operation, but discharge may extend outside of on-peak billed periods. Either way, utilization is limited to the size of the battery relative to customer BTM consumption. However, utilization tends to increase for systems conducting arbitrage *and* exporting additional capacity not being used to service load. In these circumstances the discharge is not limited to customer load, so additional capacity can be utilized and returned to the grid much like excess solar generation.

FIGURE 6-11: 2022 AVERAGE CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

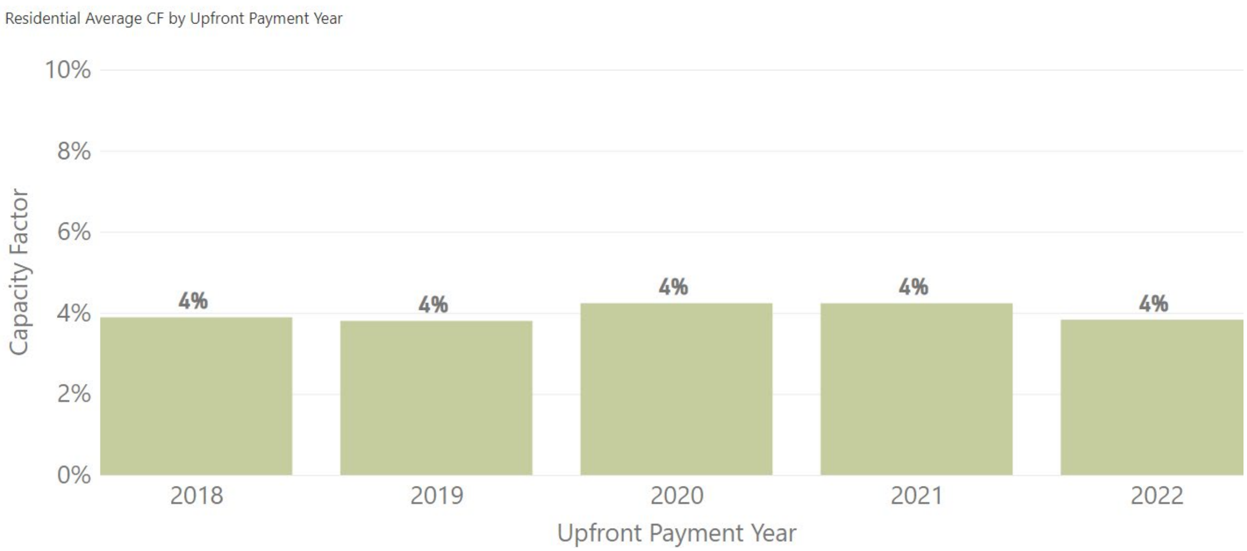
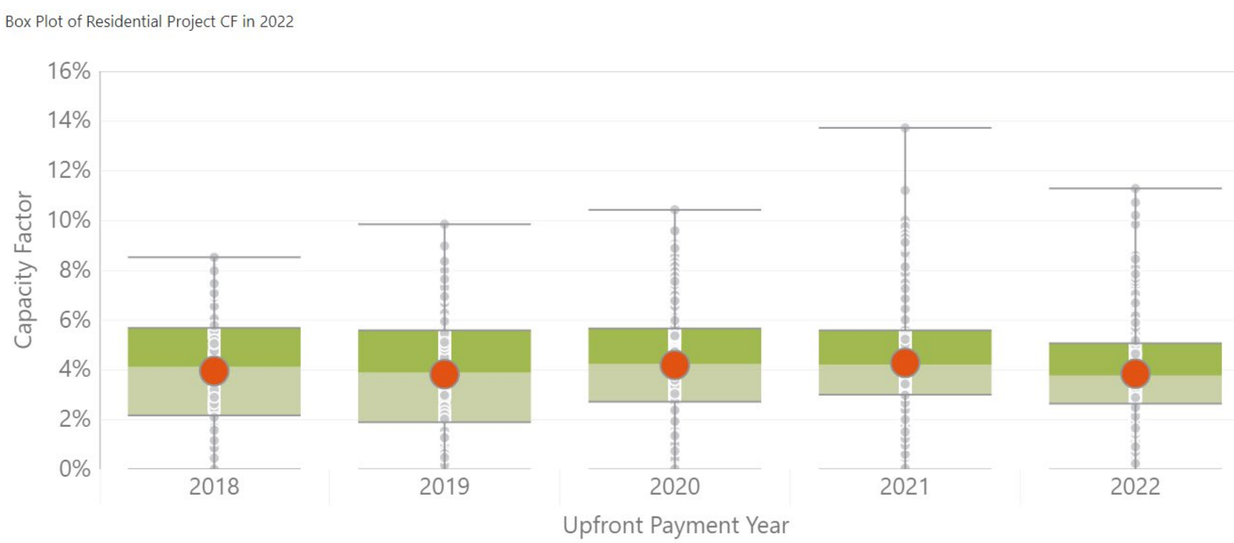


FIGURE 6-12: DISTRIBUTION OF 2022 CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



The second utilization metric tracked within the SGIP is cycling or "number of discharges" and is defined as the total kWh discharge of the system divided by the energy (kWh) capacity of the system. It represents a proxy for total number of discharge cycles throughout the year for a given system.[28]

$$Discharge\ Frequency = \frac{\sum kWh\ Discharge\ (kWh)}{Rebated\ Capacity\ (kWh)} \quad \textbf{EQUATION 6-6}$$

If a two-hour, 50-kW system (100 kWh) discharged 60% of capacity once a day, every day throughout the year, this would represent roughly 219 cycles – (50 kW x 2hr x 0.6 x 365) / 100 kWh. While capacity factors are generally greater for longer duration batteries (all else being equal), the cycling metric is proportional to the size of the battery – a two-hour battery fully discharging once a day will cycle the same amount as a 5-hour battery discharging fully once a day. With similar utilization, a storage system can exhibit an 80% RTE during one month of activity or throughout a full year of operation. The same is true for a system capacity factor. A system can exhibit a 10% capacity factor during one peak hour, or throughout a month or year because it's based on operational periods. Cycling is predicated on the magnitude of hourly discharge, but also the length of time in which the system has been operating.

FIGURE 6-13: CYCLES BY SYSTEM DURATION AND % KW HOURLY DISCHARGE

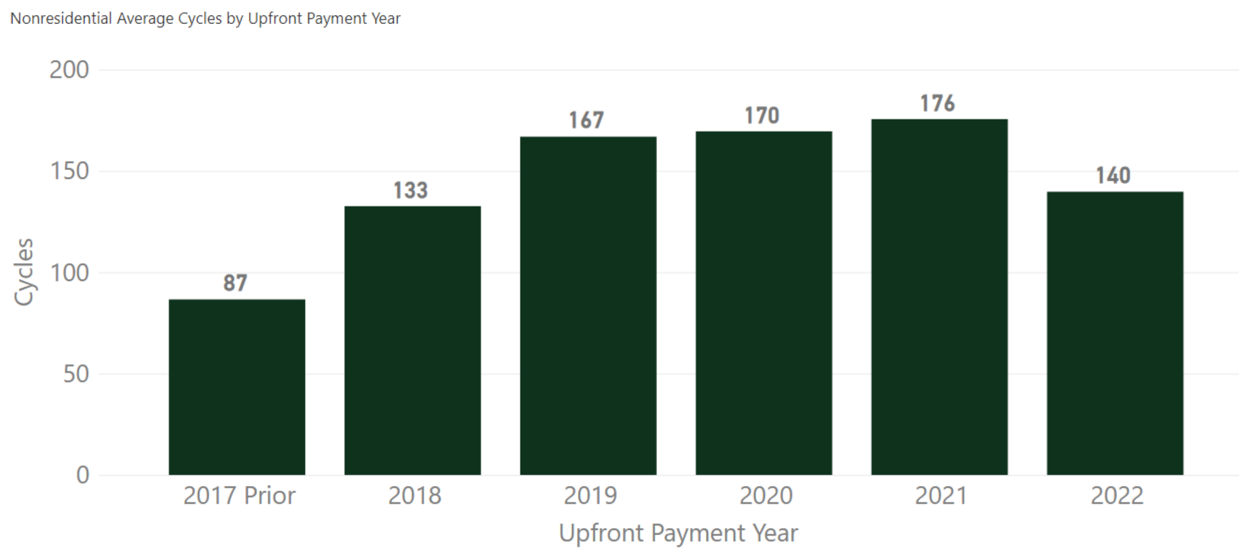
Cycles by System Duration and % kW Hourly Discharge

kW Discharge	1 hr	2 hrs	3 hrs	4 hrs	5 hrs
10%	37	37	37	37	37
20%	73	73	73	73	73
40%	146	146	146	146	146
60%	219	219	219	219	219
80%	292	292	292	292	292
100%	365	365	365	365	365

This latter point is evident in Figure 6-14 below, which summarizes annual cycling in the nonresidential sector by payment year. We observe an increase in annual utilization, from an average of 87 cycles for projects paid in 2017 and prior to 176 cycles for projects paid in 2021. However, utilization drops again for 2022 projects. The reason we observe a reduction in cycles for projects incentivized in 2022 is the reduced length of time in which a system may have been operating. Verdant develops partial year impacts for systems receiving incentives mid-way through a calendar year. So, while a system may receive their incentive and begin normal operations in August of 2022 and exhibit an 80% RTE and 8% CF during that operational period, the annual cycles are calculated off four or five months of metered data, rather than a full calendar year.

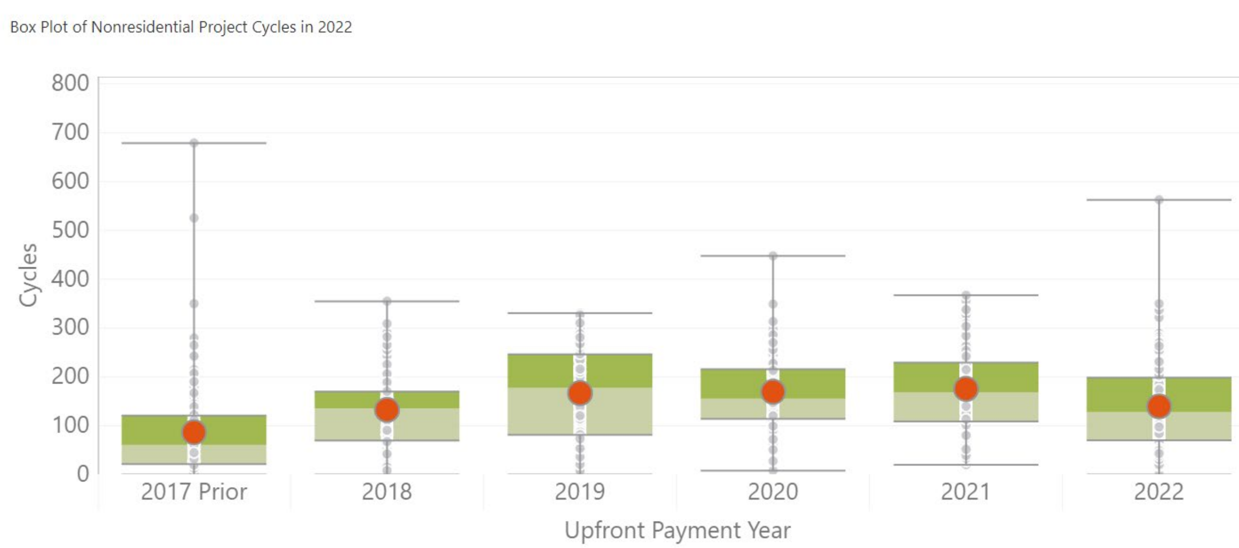
[28] The 2021 SGIP Handbook requires commercial systems to discharge a minimum of 130 full discharges per year and residential systems to discharge a minimum of 52 full discharges per year. Each time a system discharges it does not have to be a discharge of 100% capacity. Rather, the full discharge definition equates to the aggregate amount of discharges over the year (Sections 5.2.3 and 5.2.9).

FIGURE 6-14: 2022 AVERAGE ANNUAL CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Boxplots in Figure 6-15 also reveal the minimum, maximum, and median values of project utilization in 2022. Of note are projects at or near the top of each whisker with utilization greater than 365. This signifies, on average, a system fully discharging more than once per day throughout the year. Metered storage data confirm this. Some systems are actively cycling throughout the day without any clear intended purpose, while others are more nuanced and sophisticated – discharging to reduce customer noncoincident peak demand. We observe some systems discharging to keep load below a certain threshold, then charge immediately thereafter, and continue this pattern throughout the day.

FIGURE 6-15: DISTRIBUTION OF 2022 CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Residential system cycle more than the program minimum of 52 cycles. Systems performing TOU arbitrage or self-consumption may only be discharging 40-60% of available capacity each day. We also observe over 95% of residential projects paired with on-site solar PV and charging the battery exclusively from solar. The battery will only charge during PV generating hours, so we don't observe the constant daily charge and discharge cycling observed with some nonresidential systems conducting peak shaving.

FIGURE 6-16: 2022 AVERAGE ANNUAL CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

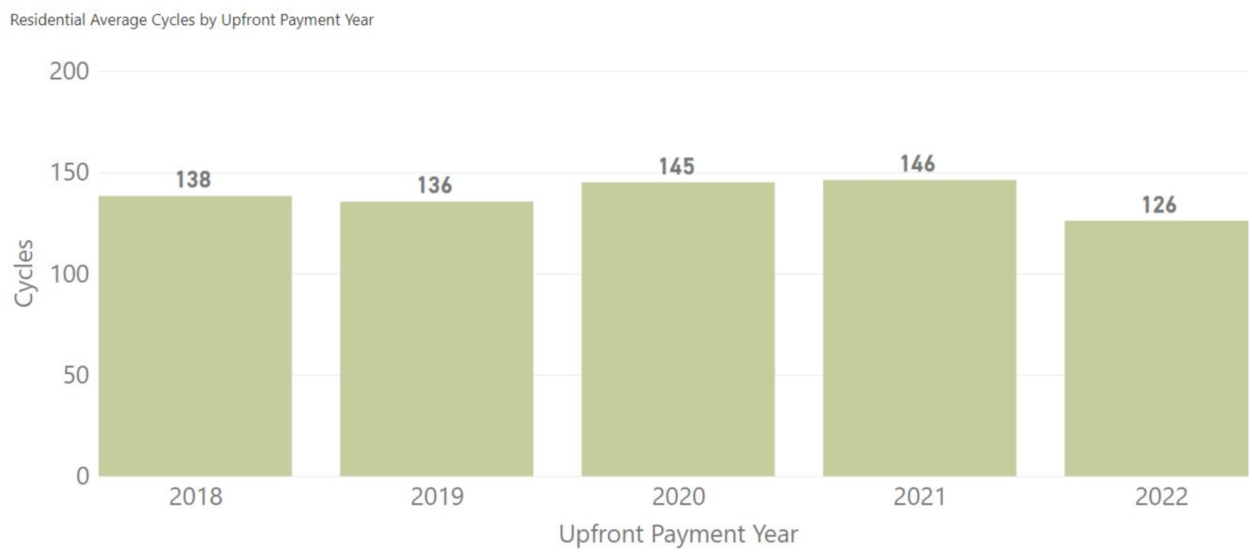
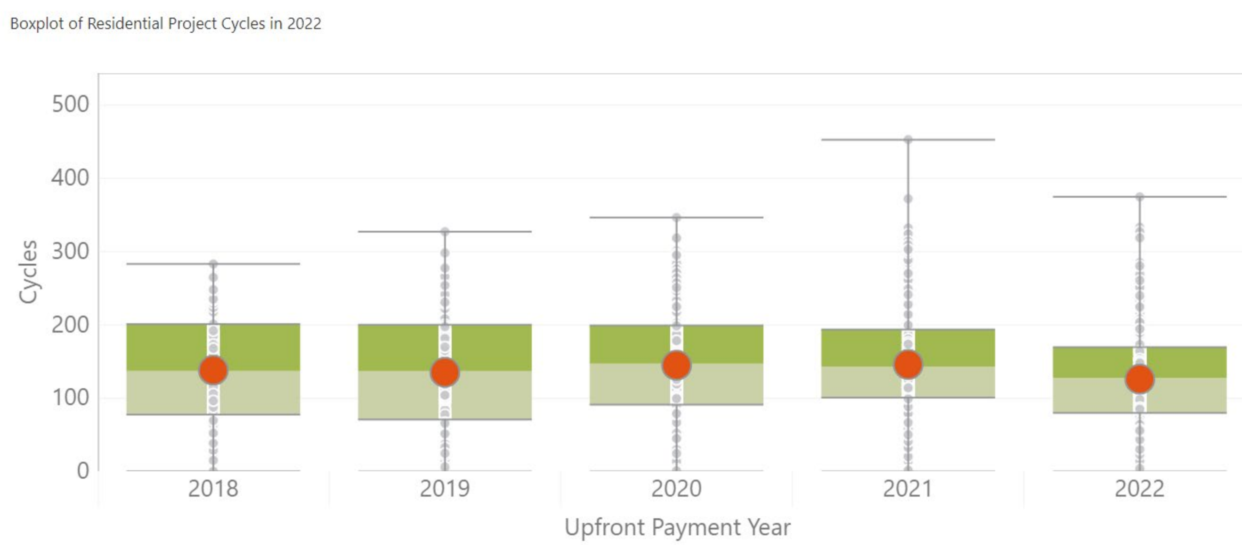


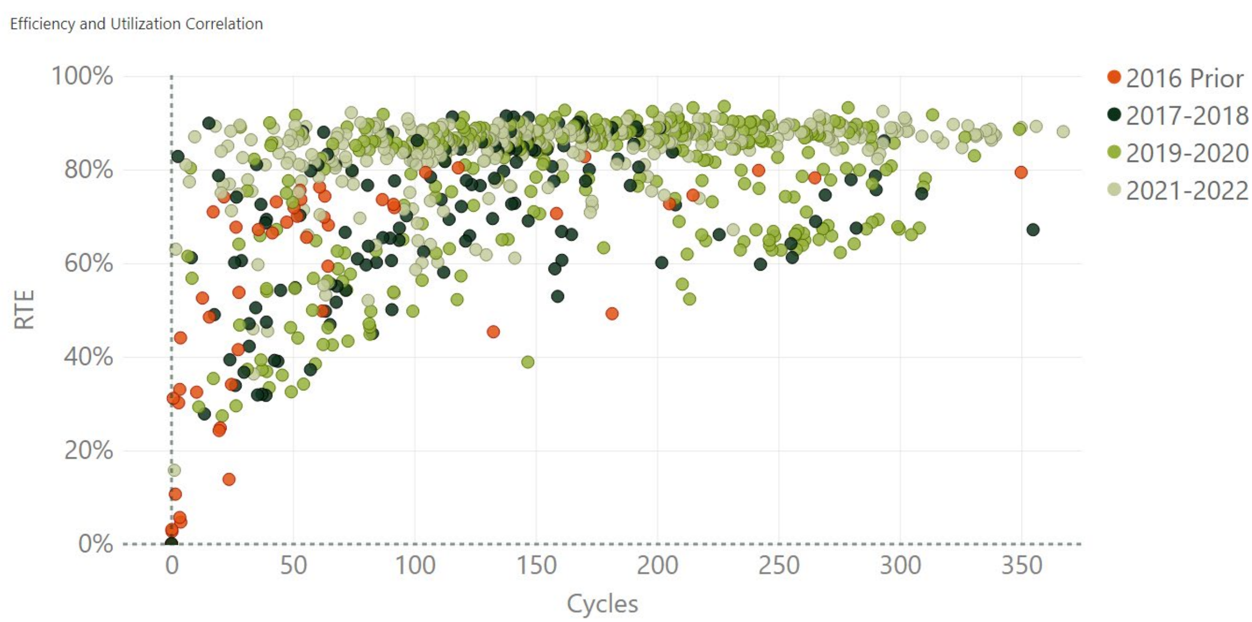
FIGURE 6-17: DISTRIBUTION OF 2022 CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



As noted previously, the RTE is a measure of the efficiency of the system – how much energy the system is discharging relative to the amount of energy the system is charging. The discharge frequency is a measure of utilization – how often is the system being discharged to perform different objectives or the total discharge kWh of the system divided by the total capacity kWh of the system. The two are related – if a system is not being utilized then it remains idle and consumes energy without providing any benefits. Depending on its size and location, an idle system is like the equivalent of a large flat screen TV being left on all day. The energy consumption can seem small, but over time, those losses add up and reduce the RTE and any potential environmental benefits of the system. Efficiency is impacted, not only by any battery losses due to AC-DC power conversion but also the parasitic loads associated with system cooling, communications, and other power electronic loads.

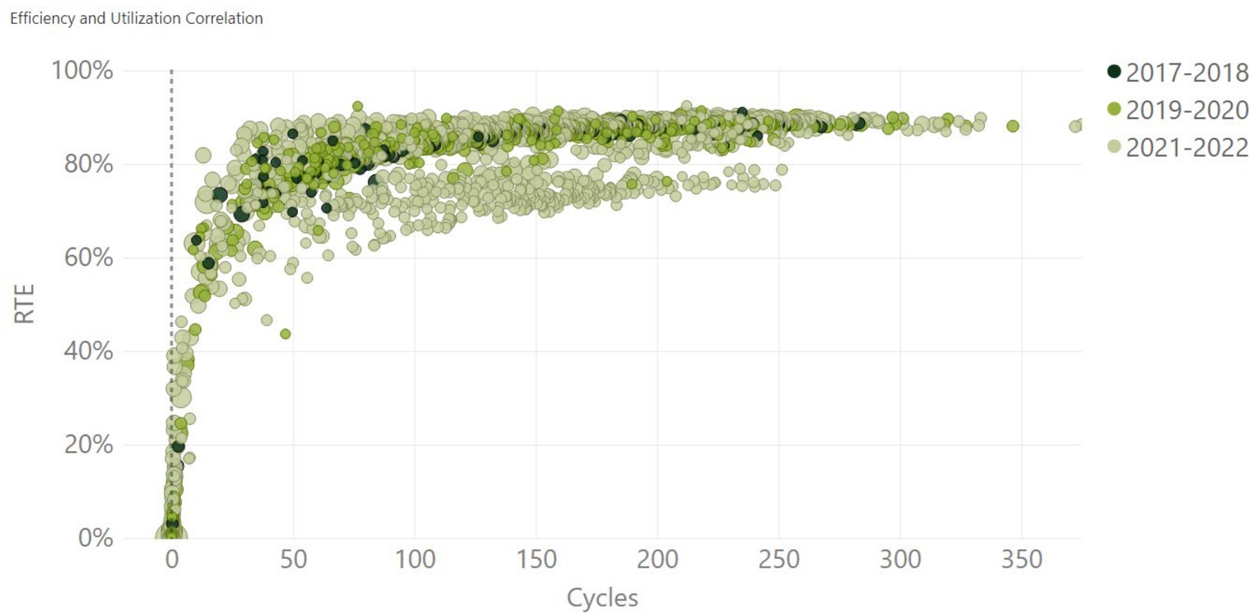
When a system is utilized more often, it often has a greater RTE. This relationship is evident in Figure 6-18 and Figure 6-19 where we map the total number of discharge cycles for each project against the efficiency or RTE of the system for the nonresidential and residential sectors, respectively. We observe a general increase in RTE (vertical axis) as a system is being utilized more often (horizontal axis).

FIGURE 6-18: RTE VERSUS DISCHARGE CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE



These figures also highlight the more prevalent inter-project variability in the nonresidential sector compared to residential. The nonresidential sector exhibits a much greater range in storage system capacity than residential systems and are installed in a variety of facility types with differing load shapes and demand requirements.

FIGURE 6-19: RTE VERSUS DISCHARGE CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE



Cross-Year Performance Impact Comparisons (2021 to 2022)

Verdant also compared the performance metrics developed for CY 2021 (provided separately in Appendix C) to those in 2022. These comparisons were made for system-level RTEs and utilization to highlight any potential changes in operation or utilization from one year to the next. Figure 6-20 through Figure 6-23 present those comparisons for RTEs and utilization. Any point on the figure above the line separating the light and gray areas represents a system with a greater RTE or utilization in 2022 than in 2021 (and vice versa). Systems along the that line exhibit identical or similar utilization and efficiencies in 2021 and 2022. Clustering along the line, especially for the RTE comparisons, suggest similar operations (and efficiencies) in 2021 and 2022 for sampled projects.

FIGURE 6-20: NONRESIDENTIAL CROSS-YEAR ROUNDTRIP EFFICIENCY COMPARISON (2021 TO 2022)

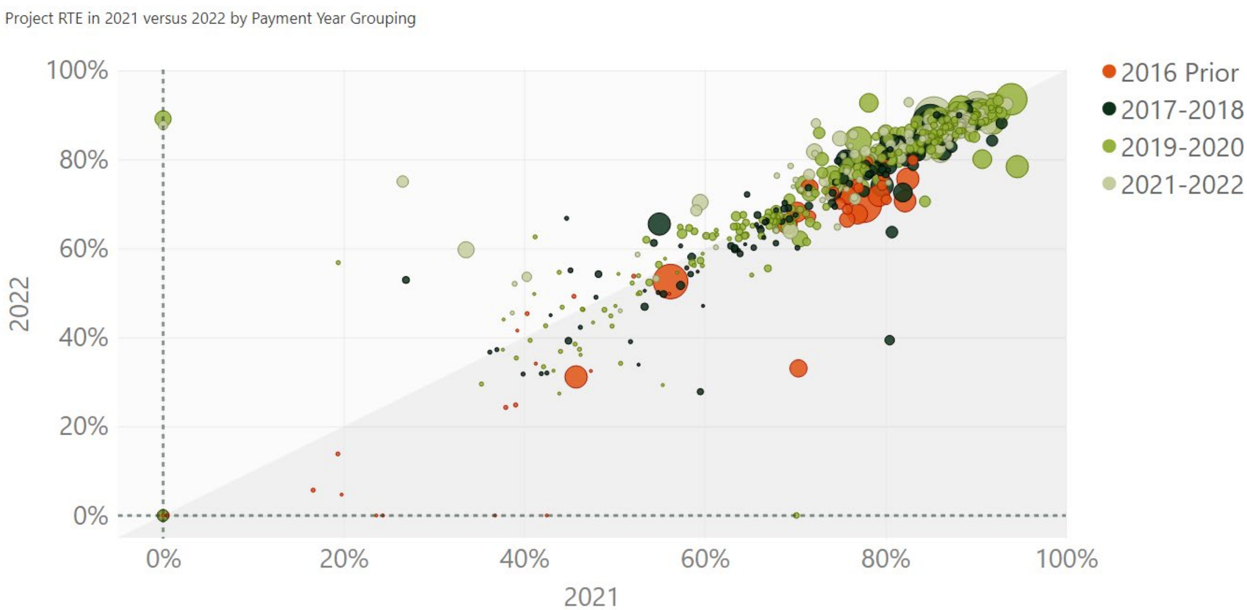


FIGURE 6-21: RESIDENTIAL CROSS-YEAR ROUNDTRIP EFFICIENCY COMPARISON (2021 TO 2022)

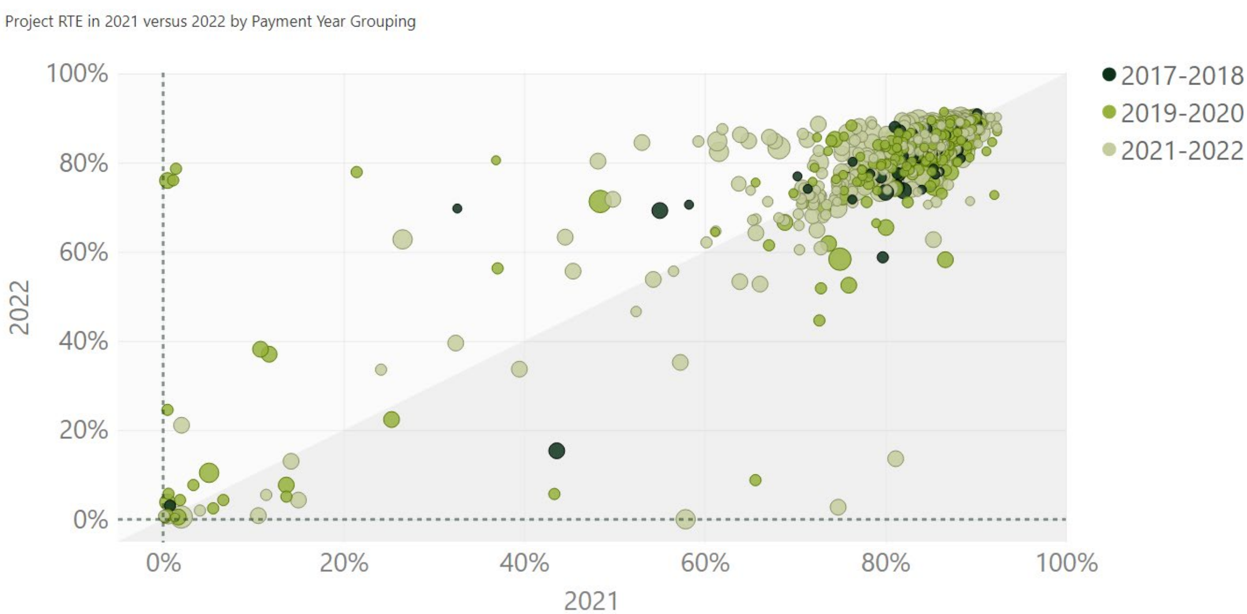


FIGURE 6-22: NONRESIDENTIAL CROSS-YEAR DISCHARGE CYCLING COMPARISON (2021 TO 2022)

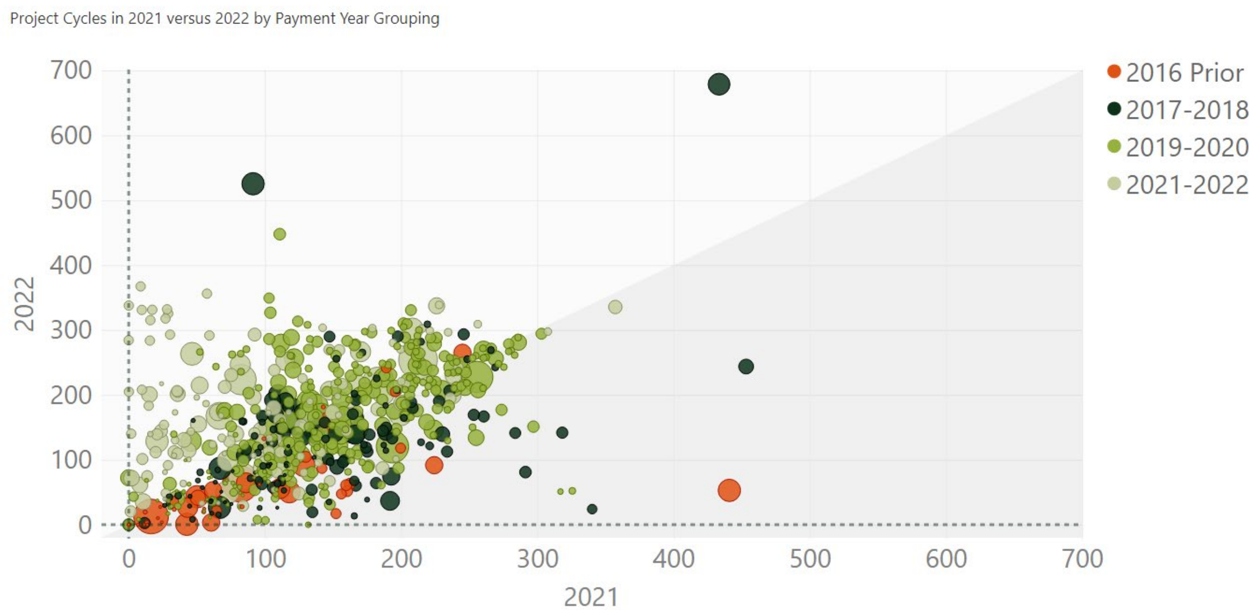
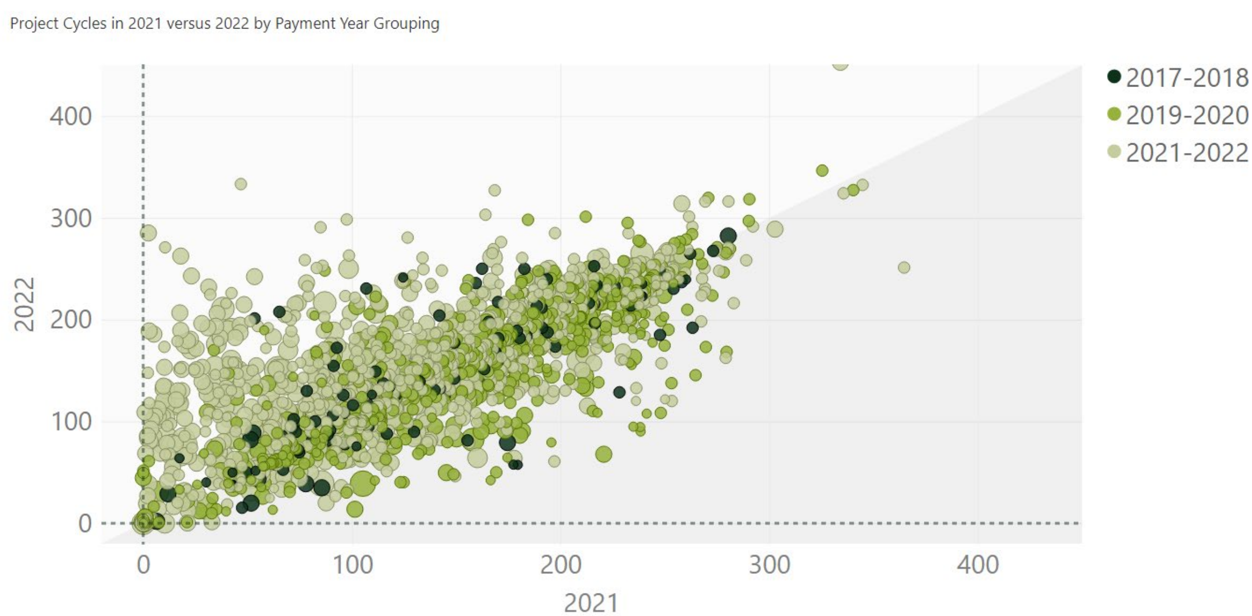


FIGURE 6-23: RESIDENTIAL CROSS-YEAR DISCHARGE CYCLING COMPARISON (2021 TO 2022)



Performance Summaries

Metrics like utilization and efficiencies play a key role in determining how storage is providing customer, utility, and environmental benefits within the SGIP. We observe changes in these performance metrics from one evaluation year to the next as program requirements and objectives evolve and energy storage

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systems become more sophisticated and capable of operating in different modes. Below we summarize the performance metrics discussed above for both the nonresidential and residential sectors, respectively. Also included are sample counts and average system capacities (in kW and kWh) for each cohort.

FIGURE 6-24: SUMMARY OF 2022 NONRESIDENTIAL PERFORMANCE METRICS BY PA

PA	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
CSE	145	242	550	74%	4%	7%	129
PG&E	254	253	623	75%	4%	7%	142
SCE	425	298	662	77%	4%	7%	159
SCG	40	393	854	79%	4%	7%	179
Overall	**864**	**280**	**641**	**76%**	**4%**	**7%**	**150**

FIGURE 6-25: SUMMARY OF 2022 RESIDENTIAL PERFORMANCE METRICS BY PA

PA	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
CSE	393	8	21	85%	4%	7%	152
PG&E	1591	8	21	79%	4%	6%	127
SCE	788	7	19	84%	5%	8%	158
SCG	36	8	22	84%	5%	8%	151
Overall	**2808**	**8**	**20**	**81%**	**4%**	**7%**	**139**

FIGURE 6-26: SUMMARY OF 2022 NONRESIDENTIAL PERFORMANCE METRICS BY PAYMENT YEAR

Upfront Payment Year	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2017 Prior	108	353	707	58%	2%	4%	87
2018	92	269	536	70%	3%	5%	133
2019	231	187	386	74%	4%	7%	168
2020	102	368	798	84%	4%	7%	170
2021	158	345	731	83%	4%	7%	175
2022	173	252	819	84%	6%	10%	141
Overall	**864**	**280**	**641**	**76%**	**4%**	**7%**	**150**

FIGURE 6-27: SUMMARY OF 2022 RESIDENTIAL PERFORMANCE METRICS BY PAYMENT YEAR

Upfront Payment Year	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2018	150	6	16	83%	4%	7%	138
2019	277	7	16	82%	4%	6%	137
2020	478	7	18	83%	4%	7%	146
2021	1090	9	23	84%	4%	7%	147
2022	813	8	20	77%	4%	6%	126
Overall	**2808**	**8**	**20**	**81%**	**4%**	**7%**	**139**

FIGURE 6-28: SUMMARY OF 2022 NONRESIDENTIAL PERFORMANCE METRICS BY BUDGET CATEGORY

Budget Category	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2017 Prior	206	330	659	66%	3%	4%	104
Equity Resiliency	89	214	1042	85%	7%	12%	119
Large-Scale Storage	536	278	581	78%	4%	7%	172
Non-Residential Storage Equity	33	178	406	82%	5%	8%	172
Overall	**864**	**280**	**641**	**76%**	**4%**	**7%**	**150**

FIGURE 6-29: SUMMARY OF 2022 RESIDENTIAL PERFORMANCE METRICS BY BUDGET CATEGORY

Budget Category	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
Equity Resiliency	633	11	28	82%	4%	6%	126
Large-Scale Storage	121	17	44	84%	4%	6%	123
Residential Storage Equity	2	8	20	88%	6%	9%	189
San Joaquin Valley Residential	51	10	26	54%	2%	3%	50
Small Residential Storage	2001	6	16	82%	4%	7%	147
Overall	**2808**	**8**	**20**	**81%**	**4%**	**7%**	**139**

FIGURE 6-30: SUMMARY OF 2022 NONRESIDENTIAL PERFORMANCE METRICS BY PROGRAM YEAR

Program Year	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2014 prior	82	413	827	61%	2%	4%	94
2015	77	343	686	72%	3%	5%	115
2016	47	162	323	66%	2%	4%	103
2017	321	217	449	74%	4%	7%	171
2018	57	455	984	81%	3%	6%	132
2019	73	389	804	85%	5%	8%	192
2020	191	245	773	84%	6%	10%	158
2021	16	208	705	78%	5%	8%	109
Overall	**864**	**280**	**641**	**76%**	**4%**	**7%**	**150**

FIGURE 6-31: SUMMARY OF 2022 RESIDENTIAL PERFORMANCE METRICS BY PROGRAM YEAR

Program Year	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2017	135	7	18	82%	4%	7%	142
2018	291	7	16	82%	4%	6%	138
2019	384	8	20	83%	4%	7%	141
2020	1311	9	22	83%	4%	7%	143
2021	565	8	19	77%	4%	7%	135
2022	122	7	16	77%	4%	7%	121
Overall	**2808**	**8**	**20**	**81%**	**4%**	**7%**	**139**

6.1.2 Generation Performance Metrics

Verdant reviewed several performance metrics for SGIP generation participants –capacity factor (CF), electrical, thermal and system efficiency, and useful heat recovery – to better quantify the efficiency and utilization of generation technologies throughout 2021-2022. We also reviewed if systems increased or decreased their utilization and efficiency over time by examining how performance changed for projects operating in both 2021 and 2022. Furthermore, we present if and how efficiency and utilization differ based on the type of generation equipment.

Capacity Factor

Energy impacts are a function of generating capacity. Capacity factor (CF) is a metric of system utilization. For generation technologies, the capacity factor is defined as the amount of energy generated during a given period divided by the maximum possible amount of energy that could have been generated during that period. A capacity factor closer to one indicates that the system is being utilized to its maximum potential.

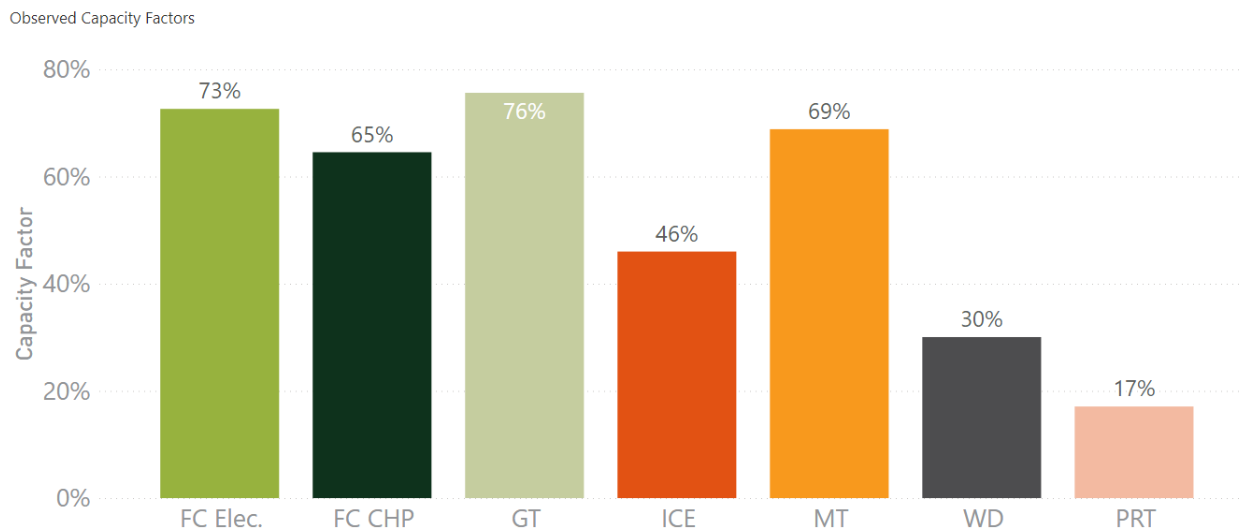
For the majority of SGIP generation projects, systems are designed to be base loaded, meaning they are operated to generate enough electricity to cover the base load needs of a customer. However, host customers often utilize their systems at capacity factors according to their individual needs. Some facilities only need full capacity during weekday afternoons, and some might need full capacity 24/7. Annual capacity factors are useful when comparing utilization between or across varieties of project sizes and technologies. To the extent that SGIP projects are cleaner (regarding greenhouse gases) than the grid energy they displace, high annual capacity factors are desirable. A capacity factor of 1.0 is full utilization regardless of a project's generating capacity.

The annual capacity factor of a generation project, CF_a, is defined in Equation 6-7 as the sum of hourly electric net generation output, $ENGO_h$, during all 8,760 hours of the year divided by the product of the project's capacity and 8,760. If a project was completed mid-year, then the annual capacity factor is evaluated from the completion date through the end of the year.

$$CF_a = \frac{\sum ENGO_h[kWh]}{Capacity\ [kW] \times Hours\ of\ Data\ Available\ [hr]} \qquad \textbf{EQUATION 6-7}$$

Figure 6-32 shows the observed weighted average 2022 capacity factors of the program's incentivized generation technologies. Gas turbines and all-electric fuel cells showed the highest capacity factors, followed by CHP fuel cells and microturbines. Other technologies showed much lower capacity factors. Wind turbines are not expected to meet the same capacity factor as other technologies due to the availability of wind in some areas. The expected capacity factor for wind turbines is 25%, whereas the expected capacity factor for other technologies is 80%.

FIGURE 6-32: 2022 OBSERVED WEIGHTED AVERAGE CAPACITY FACTOR BY GENERATION TECHNOLOGY

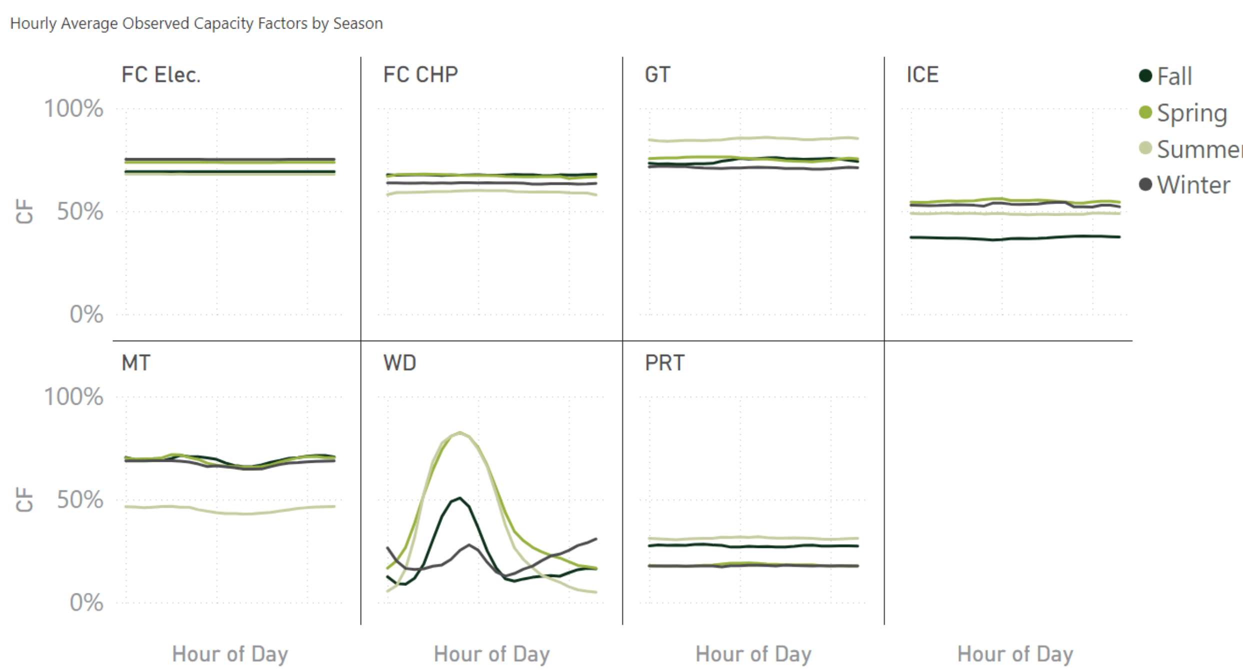


The distribution of project-specific CFs, for those projects that were operational, are shown below in Figure 6-33. Wind turbine capacity factors were tightly bunched, while internal combustion engine and pressure reduction turbine utilization exhibited substantial site-to-site variation. While fuel cell technologies generally saw higher CFs than other technologies, there was a large spread in the project-specific findings for both all-electric and CHP equipment.

FIGURE 6-33: DISTRIBUTION OF OBSERVED 2022 CAPACITY FACTORS BY GENERATION TECHNOLOGY AND INCENTIVE

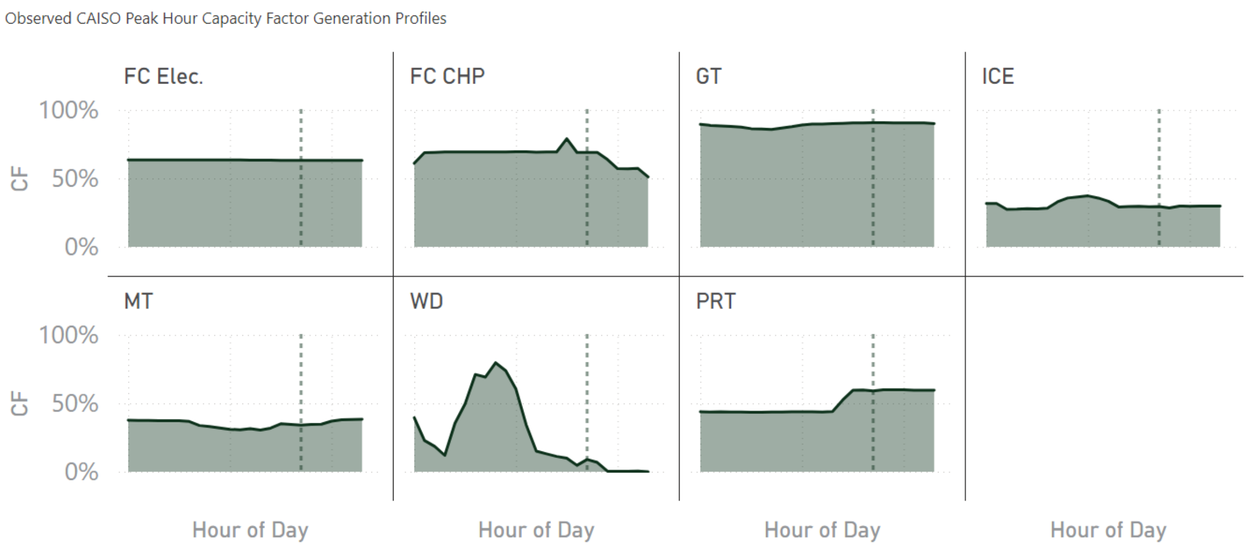
Historically, SGIP generation projects have not been designed to be ramped up and down quickly and are typically intended to satisfy a portion of the facility's base load. As such, except for wind turbines which rely on availability of wind, the capacity factors are typically quite consistent across the day. This is also evident in the program design, which specifies that most generation technologies are to meet an 80% annual capacity factor to realize their full PBI payment. Figure 6-34 presents hourly capacity factor generation profiles across different seasons for non-decommissioned generation systems. The data reiterates the fact that systems are typically designed to handle a facility's base load, and the results do not vary much by season.

FIGURE 6-34: AVERAGE 2022 GENERATION PROFILES BY EQUIPMENT TYPE AND SEASON



Higher utilization coincident with CAISO and IOU peak hours yields greater benefits to the grid than during other hours. The capacity factor generation profiles for each technology during the 2022 CAISO peak day is shown below in Figure 6-35, and the peak hour of the year is also highlighted with the grey dashed line. Across the CAISO peak hour, gas turbines were found to have the highest capacity factors at around 90% (compared to their summer average of 85%). All-electric fuel cells were found to be around 60% (compared to 68% summer average), while CHP fuel cells and microturbines hovered between 40-50% (also slightly less than summer averages of 60% and 45%, respectively). As noted previously, generation technologies are generally designed to satisfy facility base load, so there is little variation in their utilization during the peak day or peak hours versus non-peak times. However, No waste heat to power systems were generating in 2022, as the lone system within its permanency period was decommissioned prior to 2021.

FIGURE 6-35: 2022 OBSERVED CAISO PEAK DAY GENERATION PROFILES BY EQUIPMENT TYPE



Electrical, Thermal, and System Efficiency

The ability to convert fuel into useful electrical and thermal energy is measured by the system's combined efficiency in doing both. The combined or overall system efficiency is defined in Equation 6-8 as the ratio of the sum of electrical generation and useful recovered heat[29] to the fuel energy input.

$$C\eta_{system} = \frac{ENGO_{kWh} \times 3.412 + HEAT_{MBtu}}{FUEL_{MBtu,LHV}}$$

EQUATION 6-8

The higher the system's overall efficiency the less fuel input is required to produce the sum of electricity and useful recovered heat. Electric-only fuel cells do not require useful heat recovery capabilities; therefore, their system overall efficiency has only an electrical component. Technologies that recover useful heat have electrical and thermal component efficiencies. All efficiencies are reported on a lower heating value (LHV) basis.[30]

The observed overall system and component efficiencies are shown in Figure 6-36. The electrical conversion efficiency is shown in light green while the thermal efficiency in dark green. The figure also

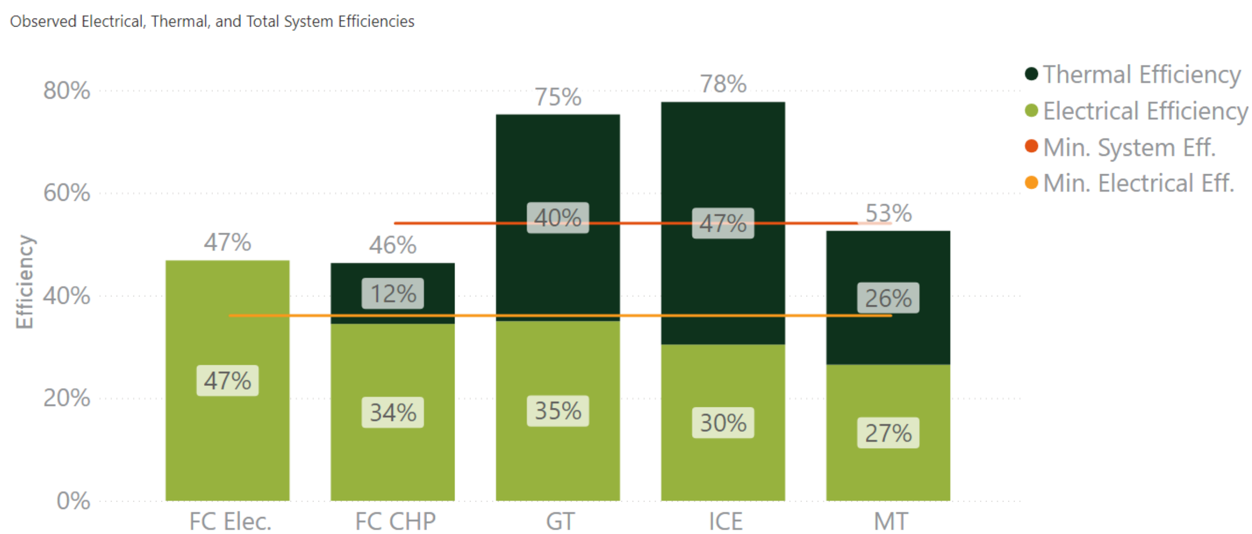
29 In the context of this report, useful heat is defined as heat that is recovered from CHP projects and used to serve on-site thermal loads. Waste heat that is lost to the atmosphere or dumped via radiators is not considered useful heat.

30 This evaluation report assumes a natural gas lower heating value energy content of 934.9 Btu/SCF and higher heating content of 1036.6 Btu/SCF for an LHV/HHV ratio of 0.9019 (Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003.)

displays red and orange horizontal lines, which represent the program minimum system efficiency targets of 54.1% LHV (or 60% HHV) for CHP and 36.1% LHV (40% HHV) for electric-only fuel cells. All-electric fuel cells, gas turbines, and internal combustion engines all met their efficiency targets.

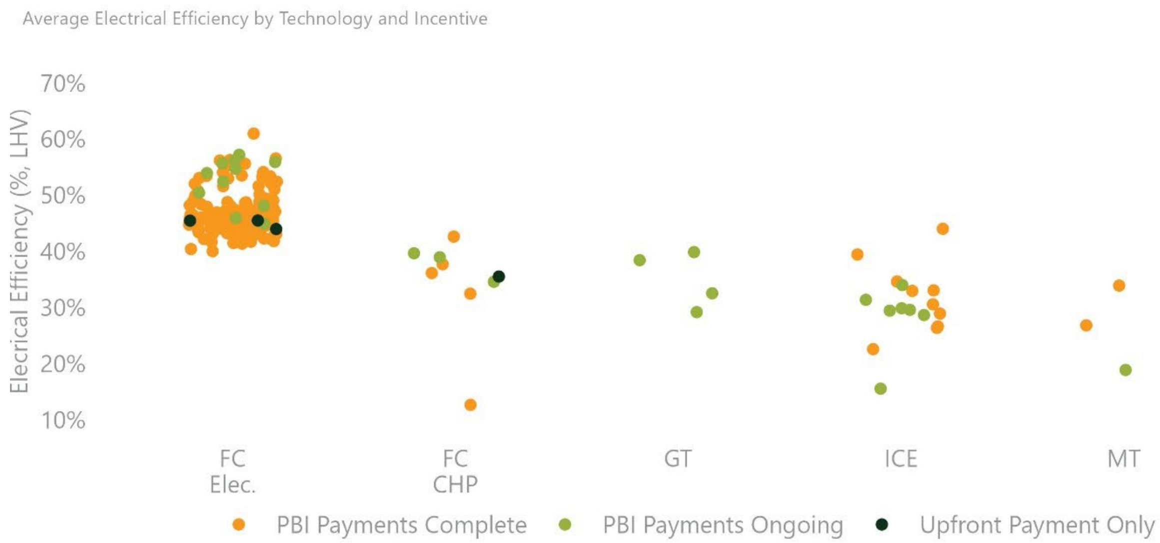
Heat recovery is the most complicated engineering challenge when implementing CHP. If the CHP generator is not appropriately sized to the annual heating and cooling loads of a building, then much of the excess heat must be dumped into the atmosphere through a radiator. Useful heat recovery loops may also be temporarily shut down due to maintenance issues. These types of events can cause this technology to have a low useful heat recovery rate and therefore an observed system efficiency that falls short of design specifications.

FIGURE 6-36: 2022 OBSERVED WEIGHTED AVERAGE ELECTRICAL, THERMAL, AND SYSTEM EFFICIENCIES BY TECHNOLOGY TYPE



* The total system efficiency displayed above the chart reflects the sum of the electrical efficiency and the thermal efficiency. However, it should be noted that the projects that go into a calculated weighted average electrical efficiency are not always the same projects that go into a calculated weighted average thermal efficiency, due to the availability of metered data.

FIGURE 6-37: DISTRIBUTION OF OBSERVED 2022 ELECTRICAL EFFICIENCIES BY GENERATION TECHNOLOGY AND INCENTIVE



Useful Heat Recovery

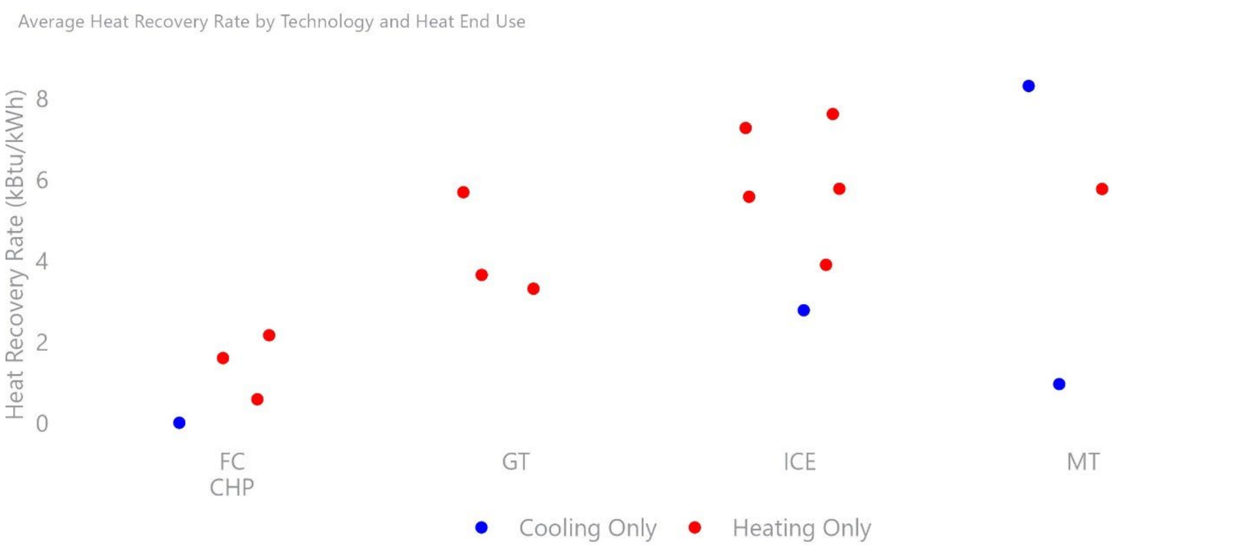
Fuel energy that enters SGIP systems is converted into electricity and heat. Certain SGIP technologies can capture this heat to usefully serve on-site end uses instead of dissipating it to the atmosphere. Except for electric-only fuel cells that achieve high fuel-to-electric conversion efficiencies, the SGIP requires useful heat recovery where natural gas is the predominant fuel. Where the predominant fuel is renewable biogas, the SGIP system is exempt from the heat recovery requirement. The biogas exemption from heat recovery was introduced in the program's first year. The end uses served by heat recovery, heating and cooling have important implications for net greenhouse gas emissions. The comparable baseline measures for heating and cooling are a natural gas boiler and a grid-served electric chiller, respectively. Useful heat recovery that displaces a baseline boiler will reduce emissions more than if it displaces a baseline electric chiller. The distribution of end uses served by useful heat recovery from SGIP systems is summarized in Table 6-1. The rebated capacity of projects utilizing heat recovery has steadily declined over the last few evaluation cycles. There were only 81 projects in 2022 that still recovered heat. This is due in part to several projects dropping out of the population due to completing their permanency periods.

TABLE 6-1: END USES SERVED BY USEFUL RECOVERED HEAT

End Use	Project Count	Rated Capacity [MW]	Percent of Rebated Capacity
Cooling Only	9	14	8%
Heating and Cooling	8	14	8%
Heating Only	64	148	84%

Heat recovery rates during 2022 for metered CHP systems are depicted graphically in Figure 6-38. The range of values is large, from 0 to 8.3 kBtu/kWh. One factor influencing heat recovery rates is electric efficiency. The higher the electrical efficiency, the less energy remains to be captured after generation of electricity. The presence of a thermal load coincident with demand for electricity generation is a second critical factor influencing average heat recovery rates.

FIGURE 6-38: DISTRIBUTION OF OBSERVED 2022 HEAT RECOVERY RATES BY GENERATION TECHNOLOGY AND END USE SERVED



Cross-Year Performance Impact Comparisons

Verdant also compared the performance metrics developed for CY 2021 (provided separately in Appendix C) to those in 2022. These comparisons were made for system-level CFs and efficiencies to highlight any potential changes in operation from one year to the next. Figure 6-39 through Figure 6-41: present those comparisons for CF and efficiency. Any point on the figure above the line separating the light and gray areas represents a system with a greater CF or efficiency in 2022 than in 2021 (and vice versa). Systems along the that line exhibit identical or similar CF and efficiencies in 2021 and 2022. Observations along the vertical zero line are projects which were operating in 2022 but were not operating and/or had not received their upfront payment yet in 2021. Clustering along the line suggests similar CF (and efficiencies) in 2021 and 2022. Most projects fell within the 60% to 90% capacity factor during both 2021 and 2022. For electrical efficiencies, none of the projects saw much variation across both years. All electric fuel cells typically saw the highest electrical efficiencies, peaking above 50%. While the combustion technologies typically saw lower electrical efficiencies, closer to 30-40%, most systems include heat recovery, which increases the overall system efficiencies. While heat data is harder to meter, and not many sites had heat data available, the data that was analyzed showed some overall system efficiencies greater than 75%.

FIGURE 6-39: OBSERVED CROSS-YEAR CAPACITY FACTOR COMPARISON (2021 TO 2022)

FIGURE 6-40: OBSERVED CROSS-YEAR ELECTRICAL EFFICIENCY COMPARISON (2021 TO 2022)

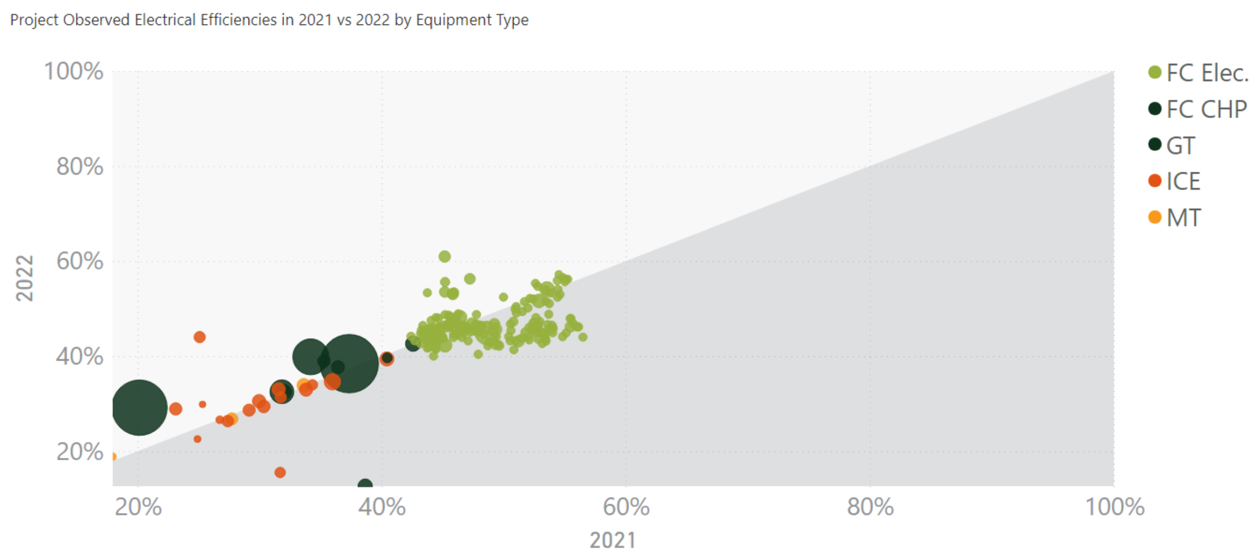
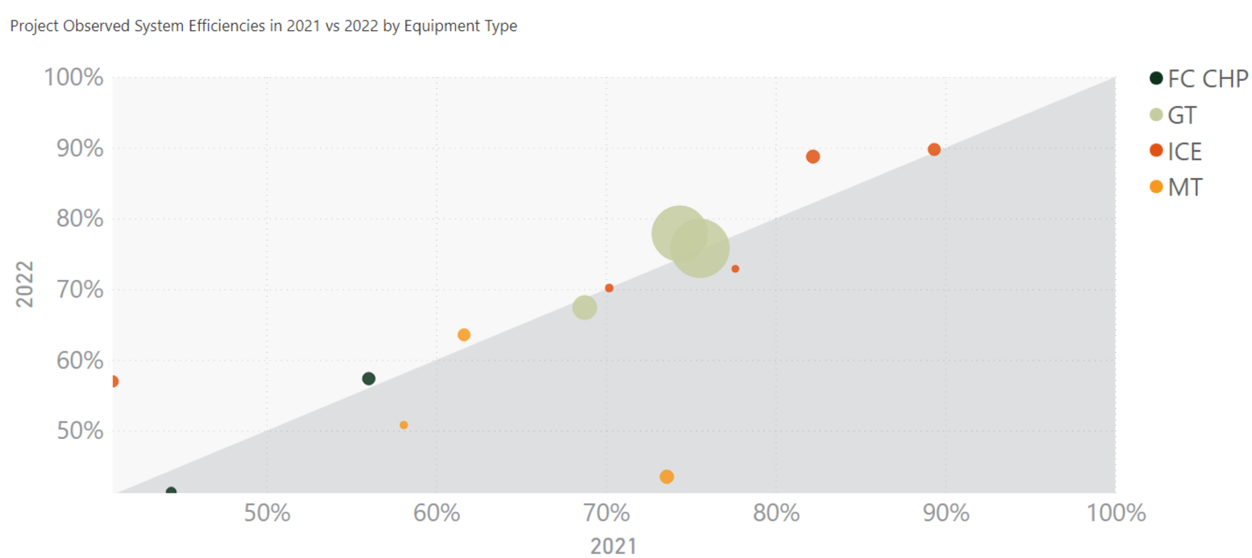


FIGURE 6-41: OBSERVED CROSS-YEAR SYSTEM EFFICIENCY COMPARISON (2021 TO 2022)



Performance Summaries

Metrics like capacity factors and efficiencies play a key role in determining how generation technologies provide benefits within the SGIP. These performance metrics are generally technology specific. Below we summarize the performance metrics discussed. Also included are observed project counts and total system capacities (in MW), and average system generation (GWh).

FIGURE 6-42: SUMMARY OF 2022 GENERATION PERFORMANCE METRICS BY EQUIPMENT TYPE

2022 Observed Generation Performance Metrics

Equipment Type	Project Count	Rated Capacity [MW]	Avg. Electrical Generation [GWh]	Capacity Factor	Electrical Efficiency	System Efficiency
FC Elec.	175	53.34	1.28	73%	47%	
FC CHP	11	10.48	4.13	65%	34%	50%
GT	4	77.21	128.86	76%	35%	74%
ICE	26	30.79	3.96	46%	30%	76%
MT	6	2.95	2.50	69%	27%	53%
WD	7	14.71	3.99	30%		
PRT	9	3.02	0.71	17%		
WHP	0	0.00				
Total	**238**	**192.49**	**3.94**	**66%**	**44%**	**64%**

6.2 CUSTOMER IMPACTS

Customers choosing to participate in the SGIP do so expecting their generation or energy storage system to deliver a variety of impacts to their energy services and bottom lines. Financial impacts are of particular importance to most participants. Electricity tariffs have a temporal dimension: the quantity *and* timing of use of electricity from the grid influence bills. As such, by operating at particular times, SGIP participants may be able to reduce the billed demand charges and/or the energy charges on their electricity bills. Findings of analysis related to customer impacts are presented below for generation systems and for energy storage systems.

6.2.1 Energy Storage

Storage systems can be utilized for a variety of use cases, and dispatch objectives are predicated on several different factors including facility and household load profiles, rate structures, other market-based mechanisms, and reliability in the event of an outage. Customers on TOU rates may be incentivized to discharge energy during on-peak hours (when retail energy rates are higher) and avoid charging until off-peak hours when rates are lower. Furthermore, customers that are on a rate that assesses demand charges during peak demand periods and/or at the monthly billing level may prioritize peak demand reduction.

Systems which are co-located or paired with an on-site generator like solar PV can exhibit substantially different behavior than a standalone system. While standalone or paired systems may exhibit the same discharge behavior – to satisfy an energy arbitrage opportunity or for self-consumption – solar pairing plays an essential role in dictating when a system charges. Systems paired with on-site solar and charging from that solar provide benefits not realized by standalone systems. These benefits will be explored in more detail in subsequent sections.

Arbitrage opportunities are guided by TOU periods which are based on the electric utility and the customer's rate schedule. During winter months and summer months – which are defined by the specific IOU rate – customers pay a different rate and, within those seasons, pay different rates for each period (on-peak, off-peak and super off-peak[31]).

Verdant examined storage discharge and charge behavior by these different indicators. The remainder of this section presents those results in more detail:

- Overall storage dispatch behavior based on Time of Day, customer sector, facility type and presence of on-site solar PV generation
- Overall customer bill impacts ($/rebated kWh) by customer sector

Storage Dispatch Behavior

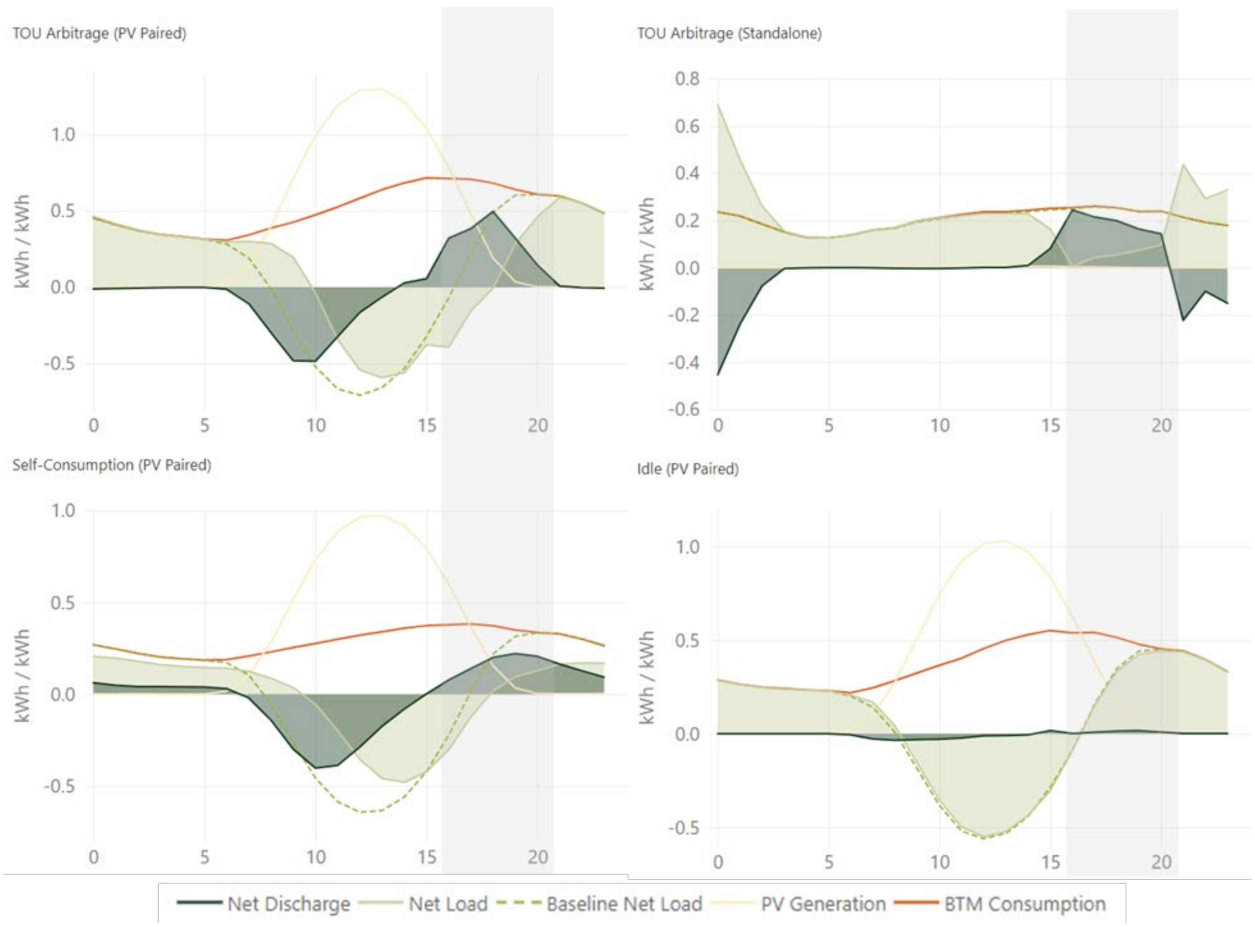
Verdant analyzed the extent to which customers utilize their storage systems for TOU energy arbitrage, self-consumption, and peak demand reduction. We observed a variety of storage use cases in 2021 and 2022 which dictate the charge and discharge behaviors throughout the year. Verdant characterized TOU energy dispatch by quantifying the magnitude of storage discharge by time of day. Retail electricity rates are higher during on-peak hours compared to off-peak and super off-peak hours, so an individual attempting to maximize the energy savings on their bill would be less incentivized to discharge outside on-peak hours. Furthermore, utility marginal costs and grid constraints are generally highest during on-peak hours, which is a transition California has observed in the past several years with on-peak periods shifting to 4 pm – 9 pm. Conversely, storage charging is best left to off-peak and super off-peak time periods when retail rates are lower, as are utility avoided costs, marginal emissions, and grid constraints.

Figure 6-43 illustrates some of the modes of operation Verdant has observed in the residential sector. For each figure, five load shapes are provided; 1) Net discharge – average system charge (-) and discharge (+),

31 These rate periods are presented across utility definition and naming convention. For this analysis, On-Peak/Off-Peak/Super Off-Peak is equivalent to Peak/Partial-Peak/Off-Peak. The definitions are the same. Rate period naming conventions have been combined for presentation purposes.

2) Customer Net load – utility observed delivered and received load, 3) Baseline Net load – the delivered and received load the utility would have seen in the absence of storage, 4) PV generation – metered on-site solar generation, and 5) BTM consumption – the customer load represented by their total end use consumption. Highlighted in light gray is the 4 pm – 9 pm on-peak period.

FIGURE 6-43: AVERAGE RESIDENTIAL DAILY WEEKDAY LOAD SHAPES



The top left figure represents the average load shapes for sampled residential customers conducting TOU arbitrage and charging their battery from on-site solar. Discharging occurs only during the 4 pm – 9 pm on-peak period (with some systems exporting) until the battery SOC reaches a pre-defined minimum. The top right figure represents the sample of customers who are also conducting TOU arbitrage, but don't have on-site solar. The system discharges throughout the peak and charges overnight, with the greatest discharge immediately after the start of the peak period (the "dump at 4" strategy). Average charge and discharge per kWh of capacity is less than in the previous, paired case. The observed increase in delivered load overnight confirms that charging.

The bottom left figure represents customers who are conducting self-consumption. This mode represents the majority of SGIP behavior and includes discharging throughout the on-peak period and thereafter until the battery SOC reaches a pre-defined minimum. The system is designed to zero out delivered load from the utility, although system constraints mean it cannot always accomplish either objective. The bottom right figure represents the sample of systems that are idle throughout the metering period. Systems here are likely in back-up mode and are not being utilized. These use cases, and others, all have an impact on how the system is utilized and the magnitude of customer, environmental, or grid impacts. The most significant one is PV system pairing.

The federal solar tax credit, also known as the investment tax credit (ITC) provides financial incentives to install solar and solar plus storage. For residential customers, the ITC was available to customers installing storage in 2021-2022 if the storage system was only charged by on-site generation like solar. For nonresidential customers, the ITC was available if the storage system was charging from on-site generation more than 75 percent of the time. Solar PV pairing is a critical source of reduced greenhouse gas emissions and utility avoided costs, because BTM storage charging from on-site solar aligns well with grid-scale renewable production and lower marginal emissions and utility energy costs. As mentioned in Section 3.1, the PV attachment rates in the SGIP population subject to evaluation are 34% in the nonresidential sector and 97% in the residential sector for this study. While solar plus storage pairing was not a design variable when developing sample stratification, by virtue of other variables included in the design, sample attachment rates for each sector are almost identical to the population shares. Population and sample attachment rates for the nonresidential and residential sectors are presented below in Figure 6-44 and Figure 6-45, respectively.

FIGURE 6-44: SGIP NONRESIDENTIAL STORAGE POPULATION AND SAMPLE SOLAR PV ATTACHMENT RATES

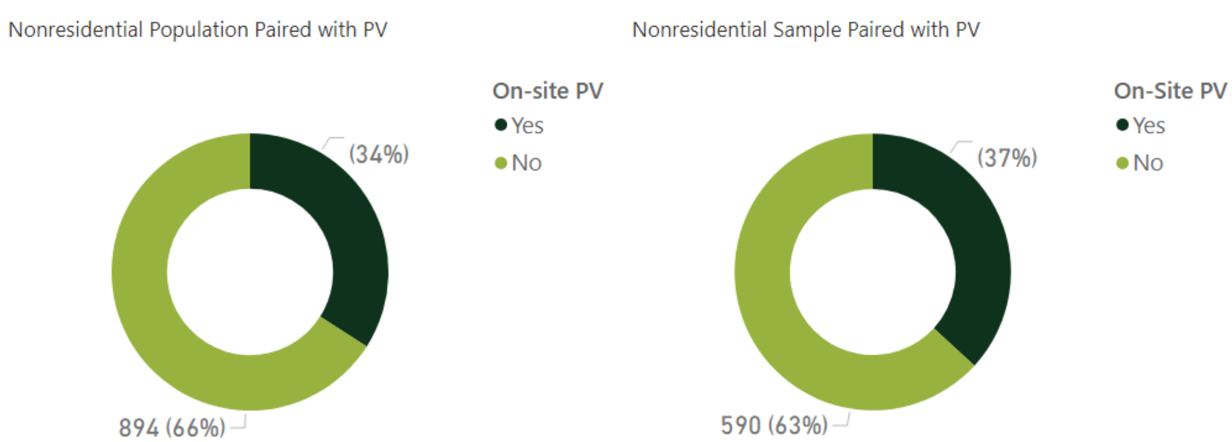
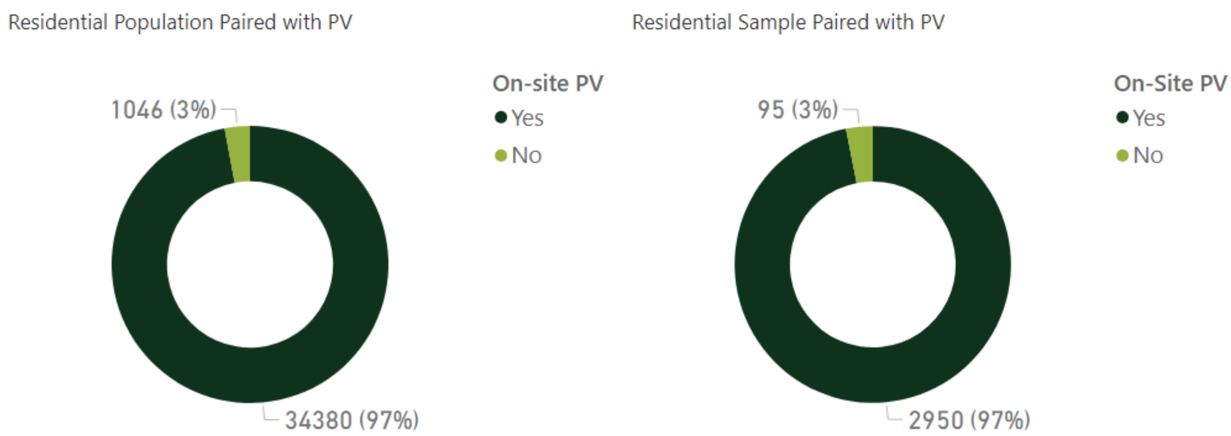


FIGURE 6-45: SGIP RESIDENTIAL STORAGE POPULATION AND SAMPLE SOLAR PV ATTACHMENT RATES



The timing and magnitude of storage charge and discharge is influenced by several factors already discussed: 1) underlying customer load shapes, 2) storage system mode of operation, 3) customer rate schedule, 4) on-site solar PV presence, and 5) storage system sizing relative to customer load. The following bar charts present average daily weekday percentage of energy discharged and charged throughout different hours of the day for residential and nonresidential systems. The exhibits also differentiate by season[32] and presence of on-site solar or not. After that, we examine the magnitude of energy discharge and charge throughout the same time periods.

Figure 6-46 and Figure 6-47 present the distribution of daily discharge by time of day as a percentage of total discharge for residential systems and nonresidential systems, respectively. At first glance, discharge is distributed throughout the entirety of the day for both sectors, with the greatest percentage represented during the on-peak 4 pm – 9 pm hours. Residential storage with PV discharges roughly 60%, and standalone systems discharge about 72% of total energy during those hours. These on-peak hours, when retail energy rates are highest, provide the greatest opportunity for customers to realize billed energy savings. If a customer is discharging any percentage of energy outside this period, this suggests they may be performing self-consumption or, for nonresidential customers subject to demand charges, may discharge to reduce non-coincident peaks. Finally, some customers who applied to the program prior to the SGIP requiring high differential TOU rates, may be on legacy rates with a different on-peak than 4 pm – 9 pm.

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[32] Summer refers to June-September inclusive. Winter represents all other months.

FIGURE 6-46: PERCENT DAILY RESIDENTIAL DISCHARGE KWH

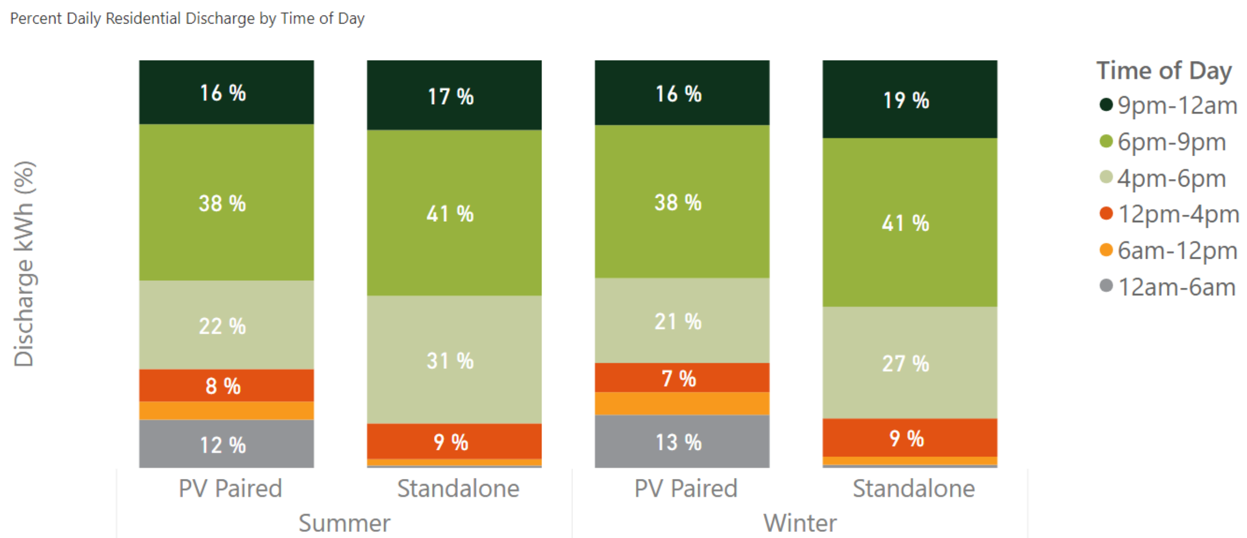
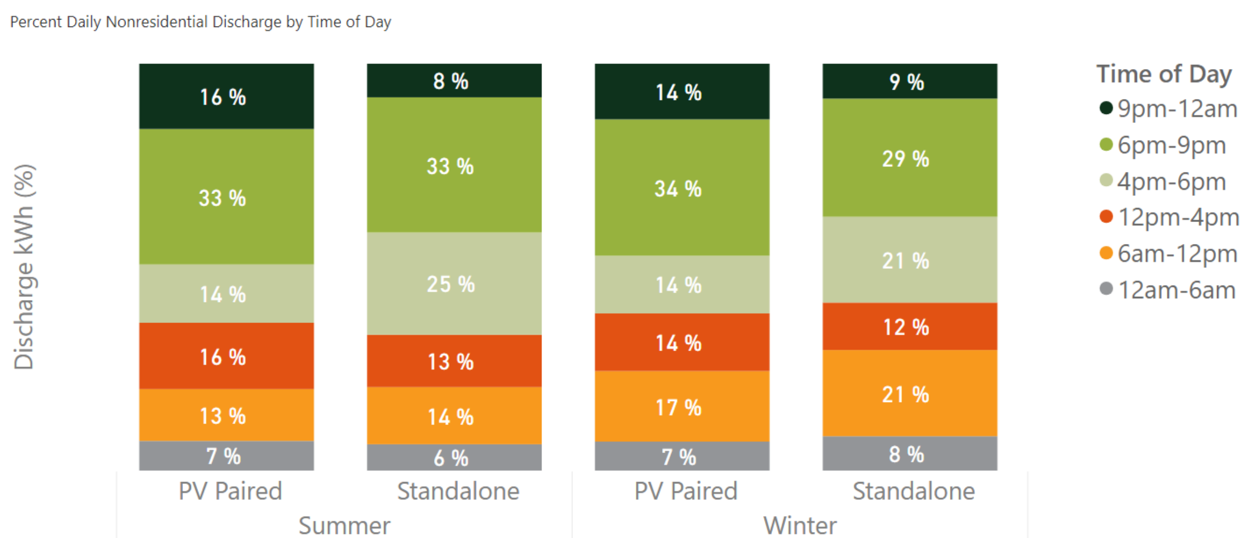


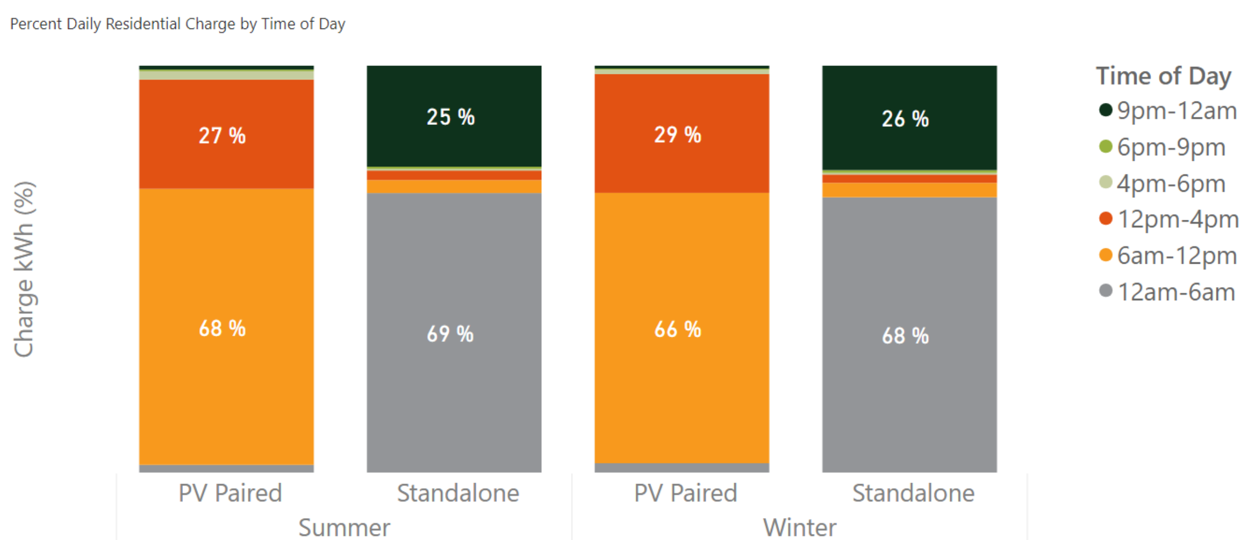
FIGURE 6-47: PERCENT DAILY NONRESIDENTIAL DISCHARGE KWH



Timing of storage charging is more limited than discharge, especially for standalone systems. Figure 6-48 and Figure 6-49 present those distributions for each customer sector. Residential systems paired with PV, on average, charge over 95% of the time throughout the hours of 6 am – 4pm. This period coincides with on-site solar generating hours and occurs prior to the on-peak period. Standalone residential systems, however, charge almost 95% of the time during late evening and early morning hours (9 pm – 6 am). Without solar pairing, standalone residential systems are discharging, on average, during on-peak periods and charging the battery thereafter.

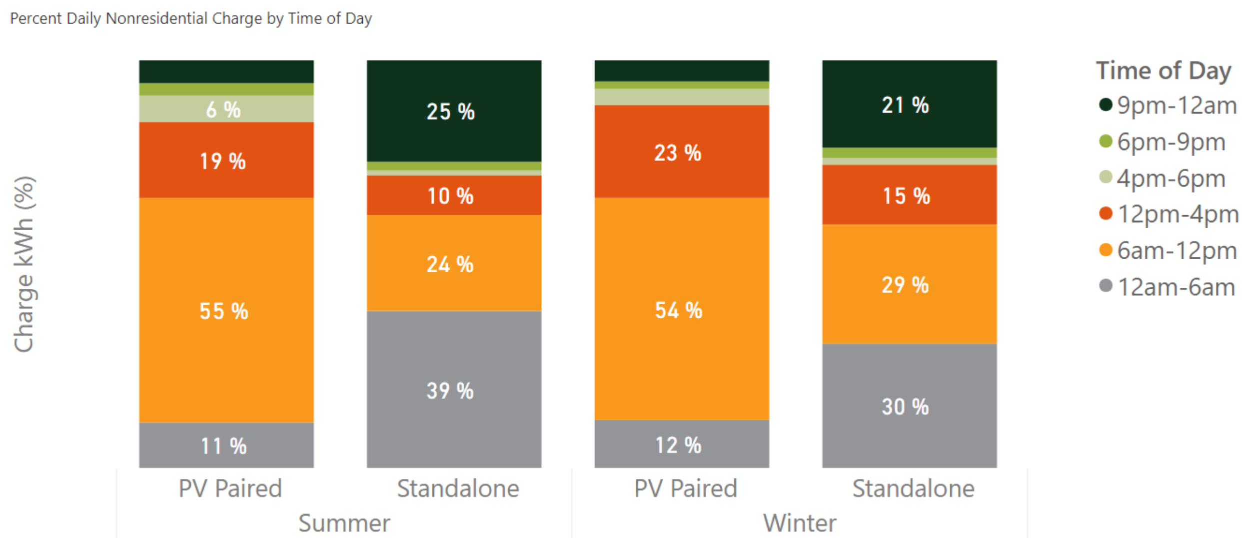
Solar PV pairing guides charging during early PV generating hours, and standalone residential systems are charging overnight outside of the on-peak period.

FIGURE 6-48: PERCENT DAILY RESIDENTIAL CHARGE KWH



For nonresidential PV paired systems, roughly 75% of charging occurs during the 6 am to 4 pm period as well. A greater distribution of charging hours for standalone systems helps confirm that many nonresidential systems are prioritizing demand charge reductions, often at the expense of energy arbitrage. Discharge occurs to reduce non-coincident demand, and we observe systems charging immediately following that discharge to increase the battery SOC in anticipation of another peak.

FIGURE 6-49: PERCENT DAILY NONRESIDENTIAL CHARGE KWH



The previous exhibits provide evidence that residential storage systems are discharging more often during on-peak periods relative to off- and super off-peak periods, and many standalone nonresidential systems are largely ignoring the energy price differential across periods and discharging more often outside on-peak periods. Solar PV pairing guides charging during early PV generating hours, while standalone residential systems are charging overnight outside of the on-peak period (the "fill up at 9" strategy).

Next, we examine the magnitude of energy discharge and charge throughout the same time periods. While a system may discharge exclusively throughout an on-peak period, it may only be discharging a small percentage of total capacity, in which case a customer may not realize bill savings and the potential utilization of the system may go unrealized. Figure 6-50 and Figure 6-51 present the average daily magnitude of energy discharge during each time of day as a percentage of the total capacity of the system. This is provided for both residential and nonresidential sectors as well as by PV pairing versus standalone systems, much like the previous exhibits. On average, PV paired residential systems are discharging roughly 45% of system kWh capacity daily throughout the summer (27% of available energy is discharged during the 4 pm – 9 pm peak alone). Standalone residential systems and paired systems operating in winter months exhibit lower utilization overall and throughout specific times of the day, presumably due to lower peak to off-peak differentials outside the summer months. Nonresidential systems, on average, are being utilized more as a percentage of system capacity, but standalone systems also exhibit reduced utilization compared to PV paired systems, with less seasonal differences than for residential systems.

VERDANT

FIGURE 6-50: RESIDENTIAL DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY

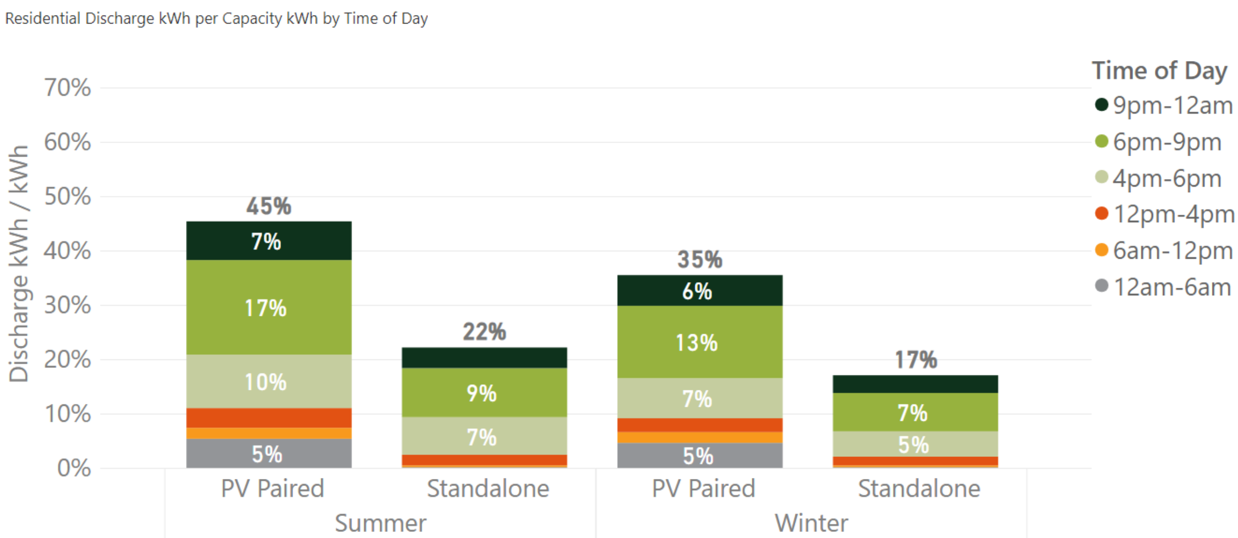


FIGURE 6-51: NONRESIDENTIAL DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY

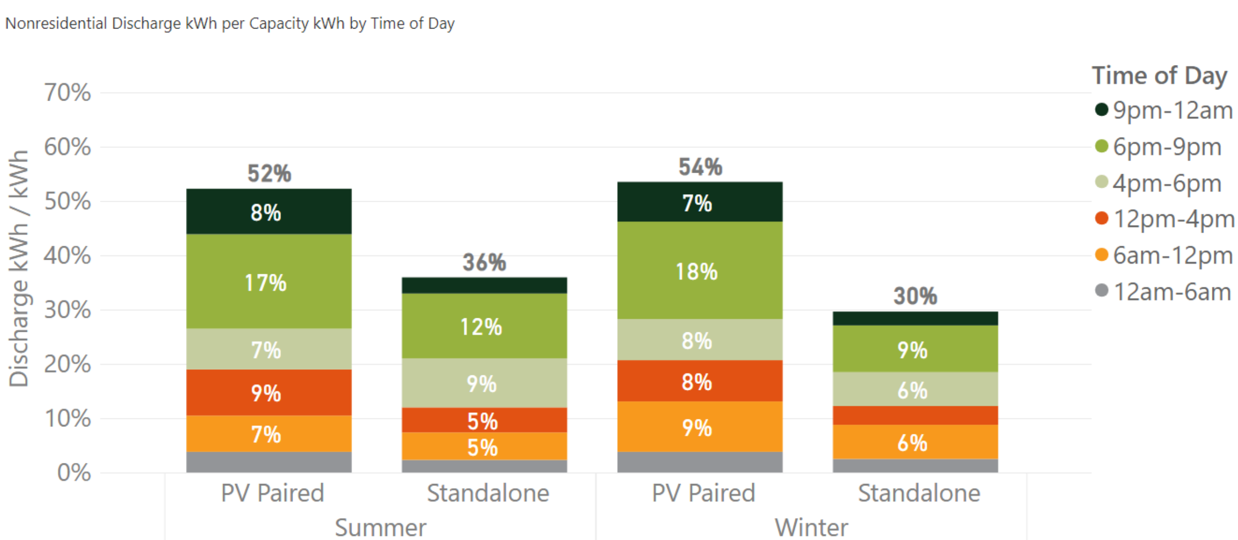


Figure 6-52 and Figure 6-53 present system charging. The first observation to note is the increased percentage of capacity used for charging compared to discharging for each segment. For example, the PV paired residential segment discharges roughly 45% of capacity daily during summer days and charges at 52% capacity. The magnitude of daily charging compared to discharge represents the RTE losses associated with AC-DC power conversion and any parasitic loads. Most of the classes of systems show similar RTE of approximately 85% (discharge percentage / charge percentage), but nonresidential standalone systems had significantly lower RTE of less than 70% (36/53 in summer and 30/43 in winter).

Second, we observe PV paired systems charging during the early 6 am – 12 pm window of on-site PV generation. Charging begins when on-site PV begins generating and stops when the battery SOC is sufficiently full.

FIGURE 6-52: RESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY

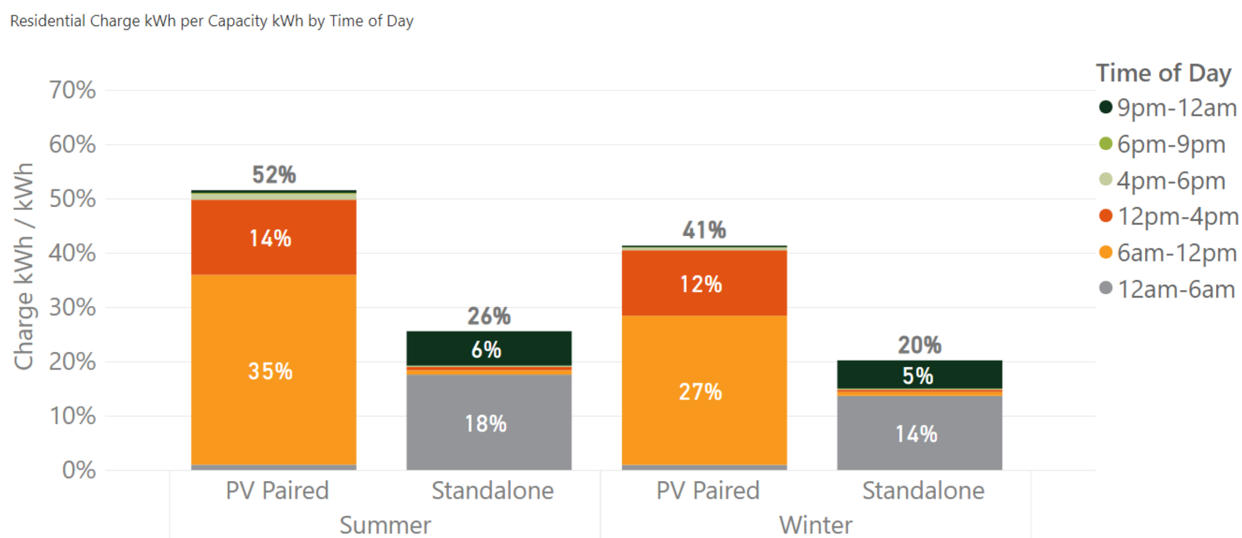
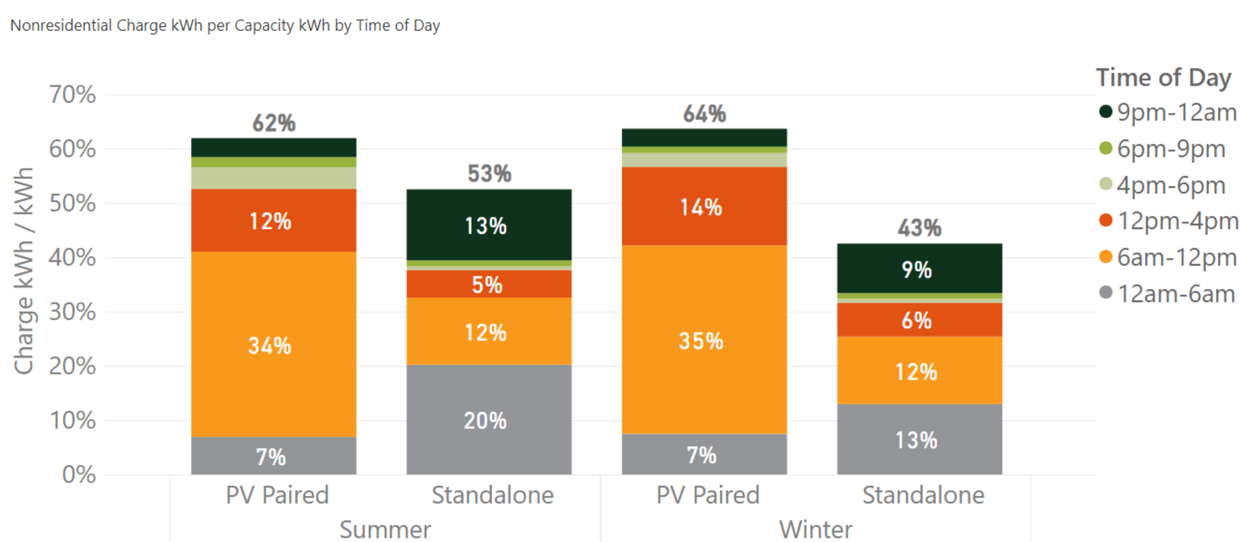


FIGURE 6-53: NONRESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY



Verdant also reviewed residential storage discharge behavior by system manufacturer. This revealed – not surprisingly – that energy storage systems are built with different operating modes and overall system capacities. Furthermore, some developers not only meter the battery at the inverter, but also meter PV production and customer net load. These metering techniques allow the battery to recognize when net load goes positive or negative and provide an opportunity for a customer to conduct self-consumption. These differing modes provide differing arbitrage opportunities and discharge patterns based on how the battery is built and how it interacts with customer load and on-site generation.

Figure 6-54 presents the average discharge as a percentage of kWh capacity for the four main system types evaluated in this study. Average storage utilization is provided for PV paired systems operating in summer months of 2022 and range from 44% of kWh capacity to 54%. Overall average utilization of Equipment A, C, and D differ slightly, but discharge utilization outside of on-peak hours provide further evidence that TOU arbitrage and self-consumption are both being exercised across system fleets. Equipment B is the only one discharging exclusively for TOU arbitrage, with almost all discharge coming during the 6 pm – 9 pm period (50% of total system kWh capacity).

FIGURE 6-54: DAILY NET DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND EQUIPMENT

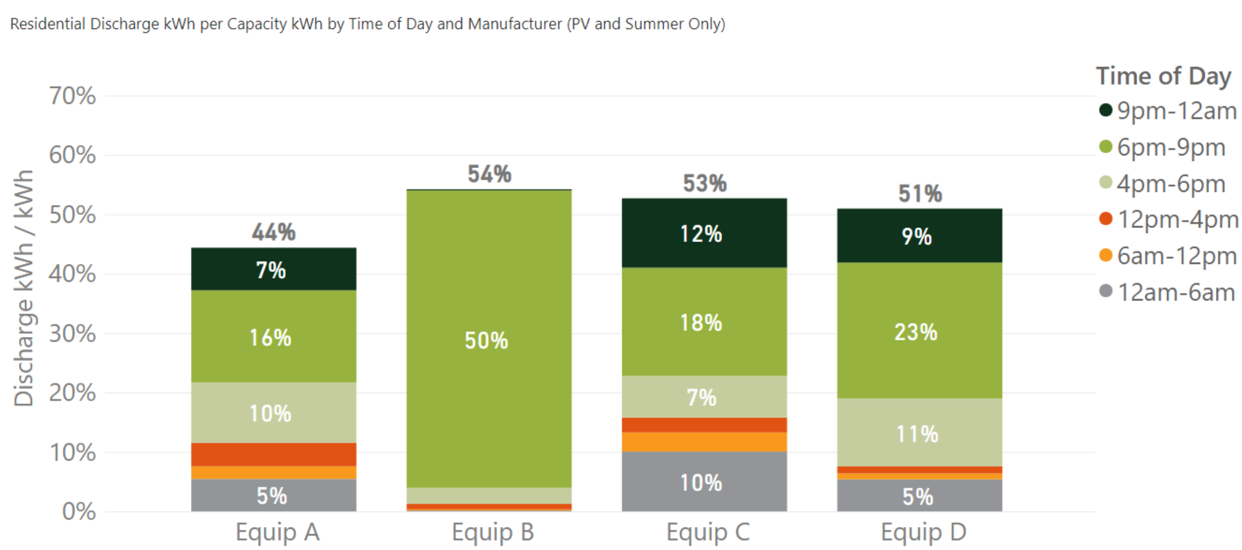
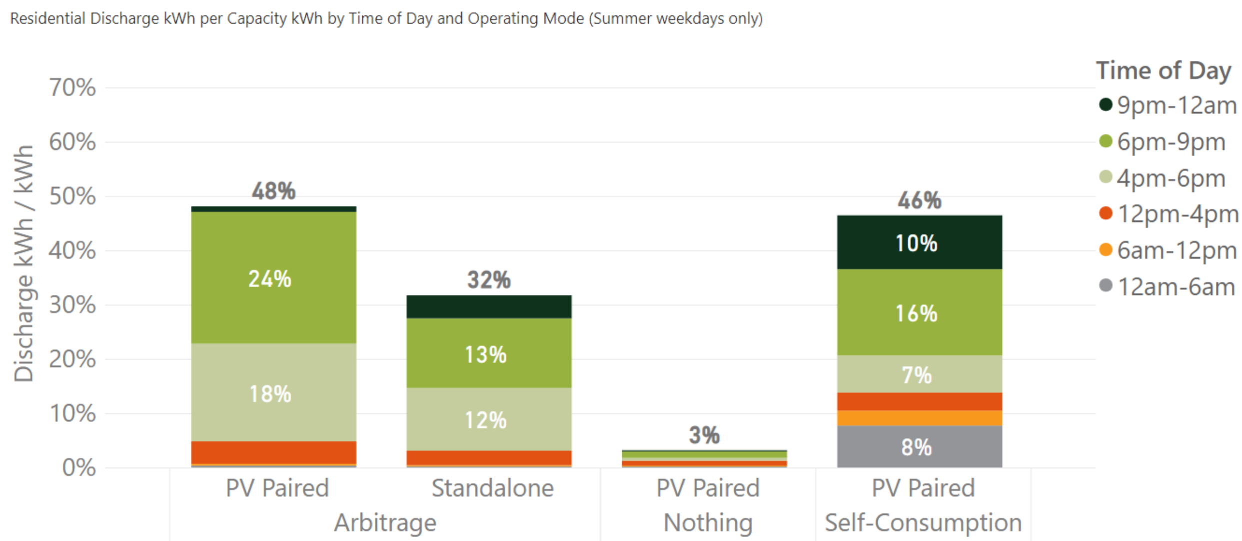


Figure 6-55 presents the average utilization for PV paired and standalone systems by different operating modes – TOU arbitrage, self-consumption, and back-up (or idle). Paired systems conducting arbitrage are discharging a similar magnitude of energy daily to paired systems conducting self-consumption (48% and 46%). This figure is the focus of the load shapes presented in Figure 6-43.

FIGURE 6-55: DAILY NET DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND OPERATING MODE



Residential storage systems are discharging more often during on-peak periods than nonresidential systems and both customer sectors are utilizing less storage capacity during peak periods than available. The previous exhibits frame storage utilization in terms of daily discharge and charge as a percentage of energy capacity. The following analyses reveal the more granular timing of dispatch behavior to further understand how storage systems are being utilized throughout the year. This was conducted by developing the average hourly charge and discharge kWh as a percentage of system kWh capacity for each month and hour during the year for residential and nonresidential systems. These summaries are further separated into percentage of discharge and charge only and whether a storage system is paired with on-site PV or not. Times represent weekdays only (Monday-Friday) and are all presented as hour beginning and in Pacific Local Time. Furthermore, months are displayed on the vertical axis and the hour of the day is exhibited across the top horizontal axis. Finally, the heatmap color gradient goes from light green – signifying the least discharge or charge as percent of capacity – to the darker green – which captures the most utilized hours in discharge or charge.

Figure 6-56 and Figure 6-57 present these results of discharge and charge of residential systems paired with on-site PV, respectively. As is evident above in the daily summaries, the greatest magnitude of discharge, on average, occurs during the 4 pm to 9 pm hours (16 through 20 in the exhibit below). The magnitude of discharge drops off thereafter, but the pattern of less and less energy being discharged as customers transition to off-peak and super off-peak periods is evident in the data. Residential storage systems paired with PV are almost exclusively charging during early to mid-morning hours, which coincides with early PV generation hours, and charging generally tails off after 12 noon when the battery SOC is sufficiently full.

FIGURE 6-56: AVERAGE HOURLY DISCHARGE (KWH) / CAPACITY (KWH) PV PAIRED RESIDENTIAL SYSTEMS

Discharge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	4%	5%	4%	3%	1%	1%	1%
February	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	4%	6%	5%	4%	2%	2%	1%
March	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	3%	4%	5%	5%	4%	3%	2%	2%
April	2%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	2%	3%	5%	5%	4%	3%	3%	2%
May	2%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	3%	3%	5%	5%	5%	3%	3%	2%
June	2%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	6%	6%	5%	3%	3%	2%
July	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	7%	6%	5%	3%	3%	2%
August	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	2%	5%	6%	7%	6%	5%	3%	2%	2%
September	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	6%	7%	6%	4%	3%	2%	1%
October	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	3%	5%	6%	5%	4%	3%	2%	2%
November	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	5%	4%	3%	2%	1%	1%
December	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	5%	3%	2%	1%	1%	1%

FIGURE 6-57: AVERAGE HOURLY CHARGE (KWH) / CAPACITY (KWH) PV PAIRED RESIDENTIAL SYSTEMS

Charge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	0%	0%	0%	2%	5%	7%	6%	5%	4%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
February	0%	0%	0%	1%	0%	0%	0%	1%	4%	7%	8%	7%	5%	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
March	0%	0%	0%	0%	0%	0%	0%	1%	4%	8%	9%	8%	6%	4%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
April	0%	0%	0%	0%	0%	0%	0%	1%	5%	8%	10%	8%	6%	3%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%
May	0%	0%	0%	0%	0%	0%	0%	2%	6%	9%	10%	8%	5%	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
June	0%	0%	0%	0%	0%	0%	0%	2%	6%	10%	11%	8%	5%	3%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%
July	0%	0%	0%	0%	0%	0%	0%	2%	5%	9%	11%	9%	6%	4%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%
August	0%	0%	0%	0%	0%	0%	0%	1%	4%	9%	11%	10%	7%	4%	3%	1%	1%	0%	0%	0%	0%	0%	0%	0%
September	0%	0%	0%	0%	0%	0%	0%	1%	4%	8%	10%	9%	7%	4%	3%	1%	1%	0%	0%	0%	0%	0%	0%	0%
October	0%	0%	0%	0%	0%	0%	0%	0%	2%	6%	9%	9%	8%	5%	3%	1%	1%	0%	0%	0%	0%	0%	0%	0%
November	0%	0%	0%	0%	0%	0%	0%	1%	4%	7%	8%	7%	5%	4%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
December	1%	0%	0%	0%	0%	0%	0%	1%	3%	5%	6%	6%	5%	3%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 6-58 and Figure 6-59 present the dispatch summaries for the sample of standalone systems. Discharge patterns are similar to PV paired systems, but with less overall utilization and overnight discharging. Time-of-Use arbitrage is the most prevelant mode of operation. The more significant difference between standalone and PV paired is timing of charge. As discussed above, the hourly charging only occurs after the on-peak period and continues through the early morning hours, especially after midnight. Without on-site PV to charge from, the system charges after discharging ends as soon as the on-bill rate drops. Note that the midnight charging (and overall utilization) increased significantly by the end of the year compared to the early months. This is likely due to SGIP customers on PG&E’s EV-2 rate, which has a super-off-peak beginning at midnight. (Recently, residential customers receiving SGIP incentives need to be enrolled in a rate with a peak to off-peak differential of at least 1.69. The EV-A was the only such PG&E rate in 2021-2022). Section 6.4.1 will discuss this further, but this behavior has a significant impact on the potential system-level GHG reduction performance.

FIGURE 6-58: AVERAGE HOURLY DISCHARGE (KWH) / CAPACITY (KWH) STANDALONE RESIDENTIAL SYSTEMS

Discharge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	2%	2%	2%	1%	1%	0%	0%
February	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	2%	2%	1%	1%	1%	0%
March	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	2%	2%	2%	1%	1%	0%
April	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	2%	2%	1%	1%	1%
May	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	2%	2%	1%	1%	1%
June	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	3%	2%	2%	1%	1%	1%
July	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	3%	3%	2%	2%	1%	1%
August	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	4%	4%	4%	3%	3%	2%	1%	1%
September	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	4%	4%	4%	3%	3%	2%	1%	1%
October	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	3%	3%	3%	3%	2%	1%	1%
November	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	3%	3%	3%	3%	2%	2%	1%
December	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	4%	4%	4%	4%	3%	2%	2%	1%

FIGURE 6-59: AVERAGE HOURLY CHARGE (KWH) / CAPACITY (KWH) STANDALONE RESIDENTIAL SYSTEMS

Charge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	2%
February	4%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	2%
March	5%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	2%
April	5%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	2%
May	6%	3%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	2%
June	7%	4%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%
July	7%	5%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%
August	9%	6%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%
September	10%	6%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%
October	10%	5%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	2%
November	10%	6%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	2%
December	11%	8%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	2%

Figure 6-60 and Figure 6-61 summarize the hourly discharge and charge of nonresidential systems paired with on-site PV. Darker green coloring during 4 pm – 9 pm suggest sytems are conducting energy arbitrage or the facility non-coincident peak and/or coincident peak occurs during those hours. With on-site solar, monthly non-coincident peaks are likely to occur during non-generating hours. Also, solar generation may

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not always meet or exceed customer BTM consumption, so the battery may be dispatched to make up the difference. The first point is evident during 6 am – 7 am. We observe nonresidential discharge during early morning facility load ramps, but prior to PV generation. The second point is evident during 12 pm – 2 pm. Facility load may exceed on-site generation during those hours, so the battery is discharged to make up the difference. Charging occurs mostly throughout early PV generating hours with some charging in the early afternoon and overnight, potentially to fill up after a demand-related discharge.

FIGURE 6-60: AVERAGE HOURLY DISCHARGE (KWH) / CAPACITY (KWH) PV PAIRED NONRESIDENTIAL SYSTEMS

Discharge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	1%	1%	1%	1%	3%	4%	2%	0%	0%	0%	2%	3%	1%	1%	3%	6%	6%	6%	5%	3%	1%	2%
February	0%	0%	1%	1%	1%	1%	4%	3%	1%	1%	1%	0%	3%	3%	1%	2%	3%	6%	7%	7%	5%	3%	2%	2%
March	0%	0%	1%	1%	1%	1%	4%	4%	2%	1%	1%	1%	2%	3%	1%	2%	2%	4%	6%	7%	6%	4%	2%	2%
April	1%	1%	1%	1%	1%	1%	4%	3%	2%	1%	1%	1%	2%	3%	1%	2%	2%	3%	4%	7%	6%	4%	2%	3%
May	1%	1%	1%	1%	1%	2%	3%	2%	1%	1%	1%	1%	2%	3%	1%	2%	2%	3%	4%	7%	7%	4%	2%	3%
June	1%	1%	1%	1%	1%	2%	3%	2%	1%	1%	1%	1%	3%	3%	1%	2%	3%	4%	4%	7%	7%	4%	2%	2%
July	1%	1%	1%	1%	1%	1%	3%	2%	1%	0%	0%	0%	2%	3%	1%	1%	3%	4%	4%	6%	7%	4%	3%	3%
August	0%	0%	0%	1%	0%	1%	2%	2%	1%	1%	1%	1%	3%	3%	2%	2%	3%	4%	4%	7%	6%	3%	2%	3%
September	0%	0%	0%	0%	0%	1%	2%	2%	1%	1%	1%	1%	2%	3%	1%	2%	3%	6%	5%	7%	6%	3%	2%	2%
October	0%	0%	0%	0%	0%	1%	2%	3%	1%	1%	0%	0%	2%	3%	1%	2%	3%	6%	7%	7%	6%	3%	1%	2%
November	0%	0%	0%	1%	0%	1%	2%	2%	1%	1%	1%	1%	2%	3%	1%	2%	4%	5%	6%	6%	5%	3%	1%	2%
December	0%	0%	0%	1%	0%	1%	2%	2%	1%	1%	1%	1%	2%	3%	1%	1%	3%	5%	5%	5%	5%	3%	1%	2%

FIGURE 6-61: AVERAGE HOURLY CHARGE (KWH) / CAPACITY (KWH) PV PAIRED NONRESIDENTIAL SYSTEMS

Charge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	2%	1%	1%	1%	1%	1%	0%	1%	5%	8%	10%	9%	6%	4%	4%	2%	1%	0%	0%	0%	1%	1%	1%	1%
February	2%	2%	1%	1%	1%	1%	0%	2%	7%	10%	11%	9%	5%	3%	4%	2%	2%	0%	0%	0%	1%	1%	1%	1%
March	2%	2%	2%	1%	1%	1%	0%	2%	6%	9%	11%	9%	6%	4%	4%	3%	3%	1%	0%	0%	1%	1%	1%	1%
April	2%	2%	2%	1%	1%	0%	0%	2%	6%	9%	10%	8%	5%	4%	4%	3%	3%	1%	1%	0%	0%	1%	1%	1%
May	2%	1%	1%	1%	1%	0%	1%	4%	7%	9%	9%	7%	4%	3%	4%	3%	3%	2%	1%	0%	0%	1%	1%	1%
June	2%	2%	1%	1%	1%	1%	1%	5%	8%	9%	8%	6%	3%	2%	3%	2%	3%	2%	2%	0%	0%	1%	1%	2%
July	1%	1%	1%	1%	1%	1%	1%	4%	7%	9%	8%	6%	3%	2%	3%	2%	2%	1%	1%	0%	0%	1%	1%	1%
August	2%	1%	1%	1%	1%	1%	1%	3%	6%	8%	8%	7%	4%	3%	3%	2%	3%	2%	1%	0%	0%	1%	1%	2%
September	2%	1%	1%	1%	1%	0%	0%	2%	6%	8%	9%	8%	4%	3%	3%	2%	3%	1%	1%	0%	0%	1%	1%	2%
October	2%	2%	2%	2%	1%	1%	0%	1%	5%	7%	9%	8%	6%	4%	4%	2%	2%	1%	0%	0%	0%	1%	2%	1%
November	2%	1%	1%	1%	1%	1%	0%	3%	7%	9%	9%	7%	4%	3%	3%	2%	1%	0%	0%	0%	0%	1%	2%	1%
December	1%	1%	1%	1%	1%	1%	0%	1%	5%	8%	9%	8%	5%	3%	3%	1%	1%	0%	0%	0%	0%	1%	1%	1%

Figure 6-62 and Figure 6-63 summarize the discharge and charge behavior of standalone nonresidential systems throughout 2022. Darker green coloring within the 4 pm – 9 pm period suggests TOU arbitrage as a prominent use case. Lower magnitude discharge, particularly throughout the 6 am to 4 pm hours throughout the year also suggest behavior indicative of non-coincident peak reduction. Systems discharge within an hour to shave or maintain peak load below a certain power threshold, then charge again to increase the SOC and prepare for another peak. This latter use case can also be seen in the charging signature of these systems throughout those same hours.

FIGURE 6-62: AVERAGE HOURLY DISCHARGE (KWH) / CAPACITY (KWH) STANDALONE NONRESIDENTIAL SYSTEMS

Discharge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	1%	0%	1%
February	0%	0%	0%	0%	1%	1%	2%	2%	1%	1%	1%	2%	1%	2%	1%	1%	2%	2%	2%	2%	2%	1%	1%	1%
March	0%	0%	0%	0%	0%	1%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	3%	3%	3%	3%	3%	1%	1%	1%
April	1%	0%	0%	0%	1%	1%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	3%	3%	3%	3%	3%	1%	1%	1%
May	1%	0%	0%	0%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	3%	3%	3%	4%	4%	1%	1%	1%
June	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	3%	2%	7%	5%	4%	4%	4%	1%	1%	1%
July	0%	0%	0%	0%	0%	1%	1%	1%	1%	2%	1%	1%	1%	1%	2%	1%	5%	5%	4%	4%	4%	1%	1%	1%
August	0%	0%	0%	0%	0%	0%	1%	1%	1%	2%	3%	1%	2%	1%	2%	2%	6%	5%	4%	4%	4%	1%	1%	1%
September	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	2%	2%	1%	2%	1%	5%	5%	4%	4%	3%	1%	1%	1%
October	0%	0%	0%	0%	0%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	4%	4%	4%	3%	3%	1%	1%	1%
November	0%	0%	0%	0%	0%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	4%	4%	3%	3%	3%	1%	1%	1%
December	0%	0%	0%	0%	0%	0%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	4%	5%	4%	3%	3%	1%	1%	1%

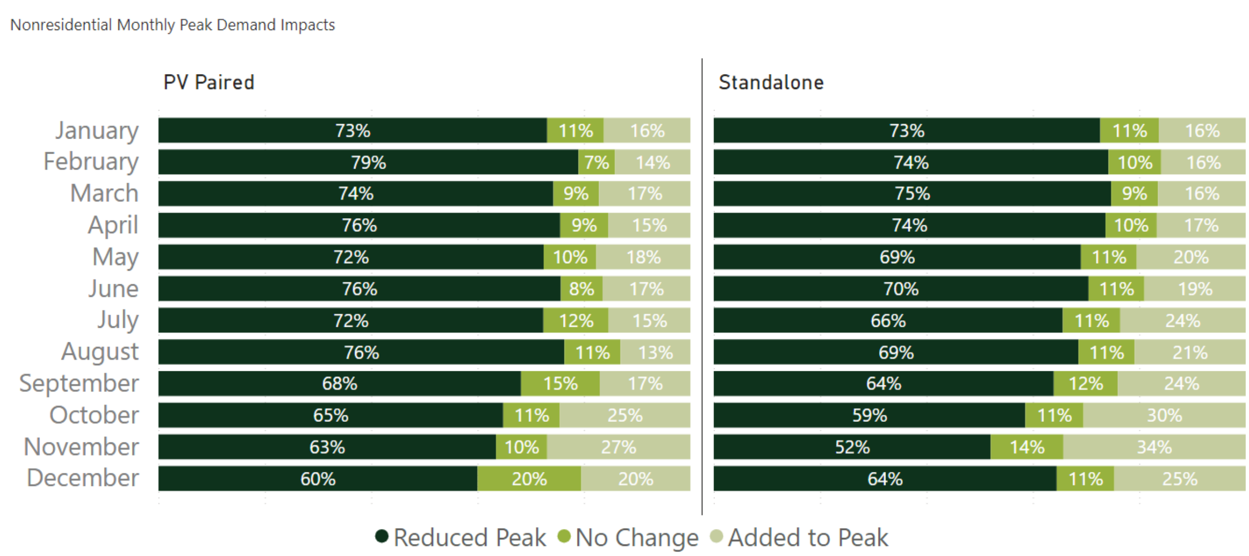
FIGURE 6-63: AVERAGE HOURLY CHARGE (KWH) / CAPACITY (KWH) STANDALONE NONRESIDENTIAL SYSTEMS

Charge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	3%	3%	3%	3%	3%	2%	2%	1%	2%	3%	2%	2%	2%	2%	3%	3%	1%	1%	1%	1%	1%	4%	3%	3%
February	4%	3%	3%	3%	3%	2%	2%	1%	3%	3%	3%	4%	2%	2%	2%	2%	1%	1%	1%	1%	1%	4%	3%	3%
March	4%	3%	3%	3%	2%	2%	2%	2%	3%	4%	4%	3%	3%	2%	2%	2%	1%	1%	1%	1%	1%	4%	3%	3%
April	4%	4%	4%	3%	3%	2%	2%	2%	3%	4%	4%	4%	3%	2%	2%	3%	1%	1%	1%	1%	1%	4%	4%	3%
May	4%	4%	4%	3%	3%	3%	2%	2%	3%	4%	4%	3%	4%	3%	2%	2%	1%	1%	1%	1%	1%	5%	4%	4%
June	6%	5%	5%	4%	4%	3%	3%	3%	3%	3%	3%	4%	3%	5%	1%	2%	1%	2%	4%	4%	2%	6%	6%	6%
July	6%	5%	5%	5%	4%	3%	3%	3%	2%	3%	4%	3%	3%	3%	1%	2%	1%	1%	3%	2%	1%	4%	5%	5%
August	6%	6%	5%	5%	4%	3%	3%	2%	3%	3%	3%	3%	4%	4%	2%	3%	1%	3%	3%	2%	1%	5%	5%	5%
September	6%	5%	5%	4%	4%	3%	3%	3%	3%	4%	3%	3%	4%	3%	2%	4%	1%	2%	3%	1%	1%	5%	5%	5%
October	4%	4%	4%	3%	3%	2%	2%	2%	3%	4%	4%	4%	4%	3%	2%	2%	1%	1%	1%	1%	1%	4%	4%	3%
November	4%	4%	4%	3%	3%	2%	1%	1%	3%	4%	3%	4%	4%	3%	3%	2%	1%	1%	1%	1%	1%	4%	4%	3%
December	4%	4%	4%	4%	3%	2%	2%	1%	3%	4%	3%	4%	4%	3%	2%	2%	1%	1%	1%	1%	1%	3%	3%	3%

Metered data collected from systems operating in 2022 confirm the prevalence of energy arbitrage and self-consumption as primary operating modes within the residential sector. Self-consumption is observed only with PV paired systems, but TOU arbitrage is observed across paired and standalone systems. The big difference in the residential sector is the timing of charge. Operating modes within the nonresidential sector are more nuanced given the significant heterogeneity of facility types and load profiles, along with how the demand charge component impacts a customer bill. We examined the monthly impact of storage discharge on facility demand or power (kW) within the nonresidential sector. If storage is optimized to reduce monthly demand charges, then examining peak demand over the course of the month provides additional insight into how storage is being utilized.

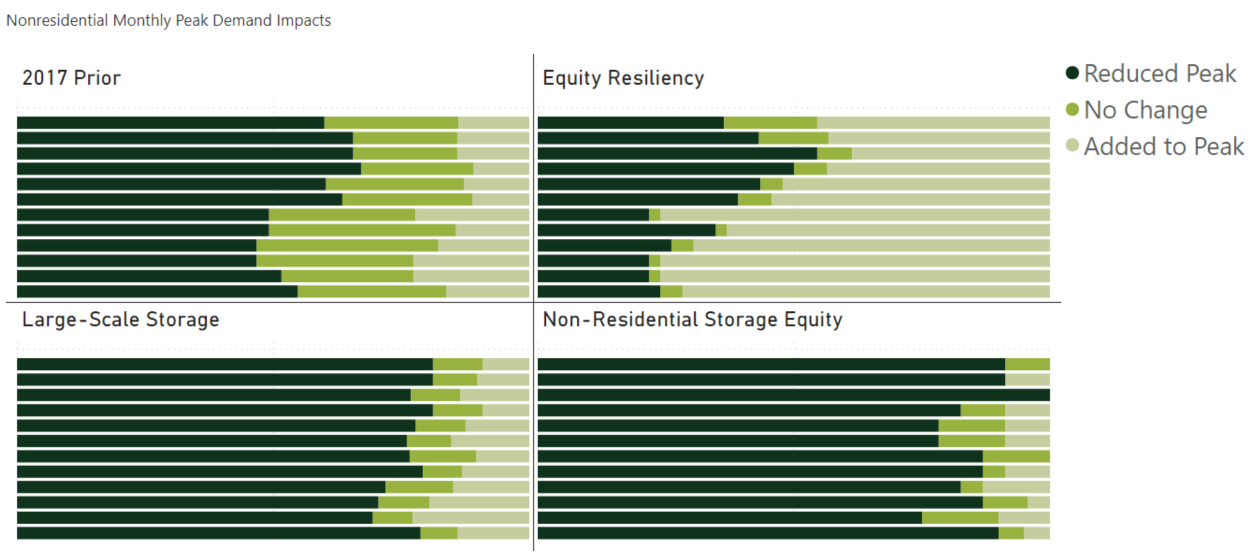
Figure 6-64 exhibits the percentage of sampled nonresidential customers – by PV paired or standalone – who either 1) reduced their monthly peak demand, 2) experienced no demand increase or 3) added to their monthly peak with how they utilized their energy storage system. Demand charges are a significant component of nonresidential customer bills, so utilizing the storage system to reduce monthly demand and coincident peak demand are critical ways to realize bill savings. The percentage of projects reducing monthly peak differs throughout the year and ranges from 60% to 79% for systems paired with PV and 52% to 75% for standalone systems in 2022. A greater percentage of projects reducing monthly peaks makes sense – if facility peak 15-minute power at a facility was reduced 50 kW by battery discharge in July for example, the customer will realize demand charge savings compared to baseline of no storage. We observe a significant percentage of idle systems – which contribute to no change in monthly facility maximum load – and systems that increase their monthly peak demand. The latter behavior would suggest a customer realized an increase on the on-bill demand portion of their bill. This behavior is more common with standalone systems, and later in the calendar year as well.

FIGURE 6-64: DISTRIBUTION OF MONTHLY NONRESIDENTIAL PEAK DEMAND IMPACTS



With a sector as dynamic and heterogeneous as the nonresidential one, it's difficult to surmise how and why system performance may vary and lead to different outcomes like the ones exhibited above. We do know most systems installed earlier in the program, and many of the more recent long duration batteries installed at critical services facilities and incentivized through the Equity Resiliency Budget (ERB), are standalone (non-PV paired). Furthermore, ERB systems are designed to provide sustained resiliency in the event of an outage, so are not designed as peak shaving technologies. Distributions of monthly facility peak demand impacts are presented below in Figure 6-65 by budget category. The top two figures exhibit the distributions for those earlier program installations, and those installed within the ERB. Both groups of projects signal less reductions in monthly peak than the large-scale storage and storage equity categories, but for different reasons. A greater percentage of ERB participants added to their monthly peak in 2022, whereas those receiving incentives in 2017 and prior exhibit a greater percentage of systems with no peak demand change. We also observe a greater percentage of ERB systems adding to their monthly peak throughout the year.

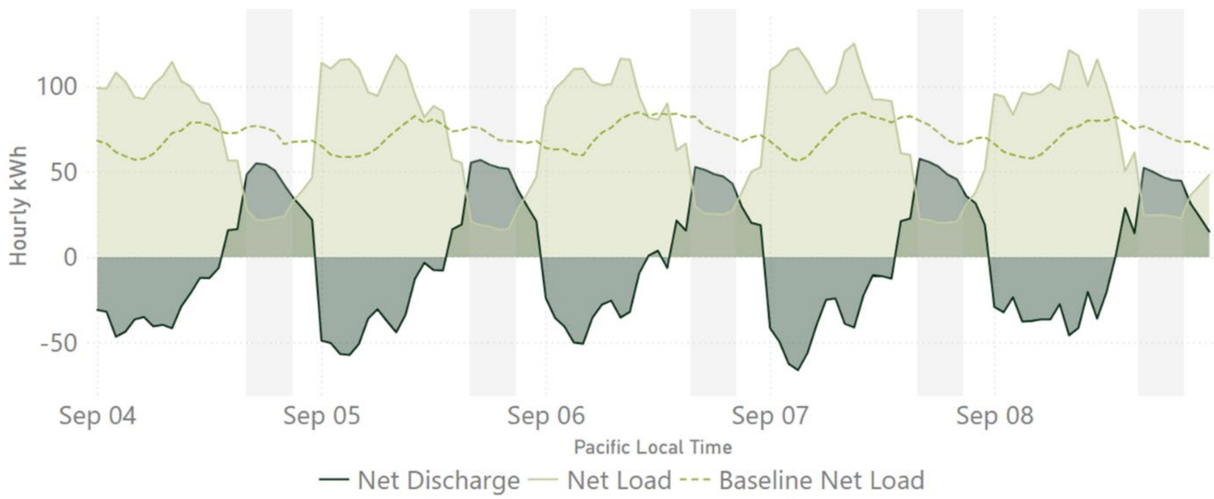
FIGURE 6-65: DISTRIBUTION OF MONTHLY NONRESIDENTIAL PEAK DEMAND IMPACTS BY BUDGET CATEGORY



The ERB case is an interesting one. Projects could incur significant bill increases if system discharge and charge behavior leads to new and larger peaks. We already mentioned ERB systems exhibit much larger capacities and are designed to provide long duration, sustained resiliency to low-income communities in the event of an outage. Many of the projects in this category are groceries, hospitals, or municipal facilities like wastewater treatment plants. Furthermore, most installations in this category are not paired with on-site PV. Verdant reviewed the load profiles and storage utilization for systems in this category to better explain how this behavior occurs. Results are provided below in Figure 6-66.

Discharge (+) and charge (-) are presented in shaded dark gray, metered delivered load is shaded light green, and baseline load – average expected load in the absence of storage – is presented as the dashed green line. Also provided for each day in shaded rectangles are the 4pm to 9 pm on-peak hours. These load shapes confirm the results of the previous section – installations in the ERB, particularly standalone installations, increase non-coincident peak demand. Storage discharge begins around 1 pm and ends around midnight each day. Hourly peak discharge reaches roughly 50 kW, on average. Battery charge occurs overnight and extends throughout the following day until the battery is sufficiently full and begins discharging again. Charging overnight results in a new peak, while discharging reduces load throughout some of the more critical coincident peak hours. Discharge behavior in this case is particularly important because the five-day period below represents a protracted heat dome event, where high and sustained temperatures throughout the west created significant grid constraints and life-threatening conditions.

FIGURE 6-66: AVERAGE 5-DAY LOAD SHAPES FOR NONRESIDENTIAL EQUITY RESILIENCY PROJECTS



We also examined monthly peak demand reductions relative to system capacity by calculating the difference between the highest 15-minute demand (kW) in the absence of storage – the counterfactual baseline – and the highest metered 15-minute demand during each customer bill period. Verdant then normalized that difference by the kW capacity of the system. A customer would realize billed demand savings if the difference between the observed and baseline was positive. It also signals the maximum system capacity used for non-coincident demand reduction. For example, where monthly baseline load would have been 100 kW in the absence of storage and the peak observed load was 80, that delta represents the change in billed demand of 20 kW. If this demand reduction was serviced by a 20-kW system – which would be discharging at full capacity in this example – the reduction would represent 100% of capacity. With a 100-kW system, utilization would be at 20% of capacity.

Figure 6-67 conveys those results for the nonresidential sector. We observe variability in average customer peak demand reductions (and increases) across budget category and throughout the year. Large-scale storage and equity exhibit similar reductions, ranging from 14% of rebated capacity to 30%. Older systems (labeled 2017 and prior) exhibit much lower monthly demand reductions – ranging from 10% of kW capacity to 16% in April. Equity Resiliency projects increase load, on average, especially during the latter months of the year. This is consistent with the more prevalent increases in load during those months presented above in Figure 6-65.

FIGURE 6-67: MONTHLY PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

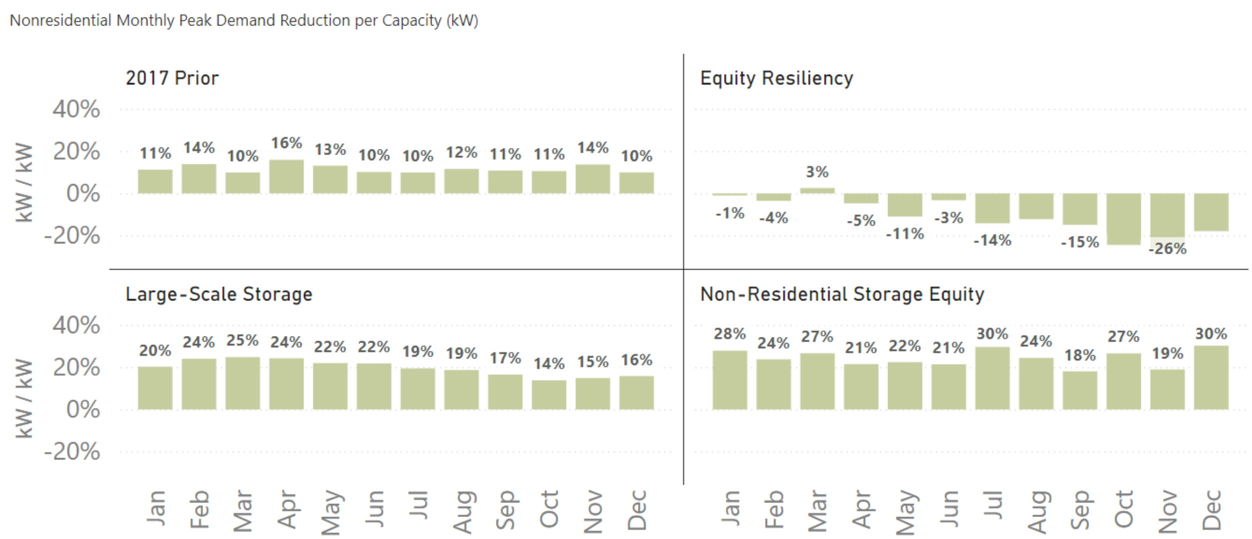


Figure 6-68 conveys the monthly average peak demand reduction as a percentage of a customer's monthly avoided peak. Results signal if a customer's monthly peak demand would have been 100 kW in the absence of the storage system – this is the baseline calculated load presented as the dashed green line above in Figure 6-66 – and they reduced peak demand by 10 kW with storage discharge, then the customer reduced their peak demand by 10%. This indicator measures the peak utilization of storage as a function of facility size. Low positive percentages signal either 1) system under-utilization, 2) underlying load that's much greater than system capacity, or 3) energy arbitrage or longer duration demand reduction as primary use cases. On average, nonresidential customers are reducing their peak demand by 6% of baseline peak load with significant inter-budget category variability.

FIGURE 6-68: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW)

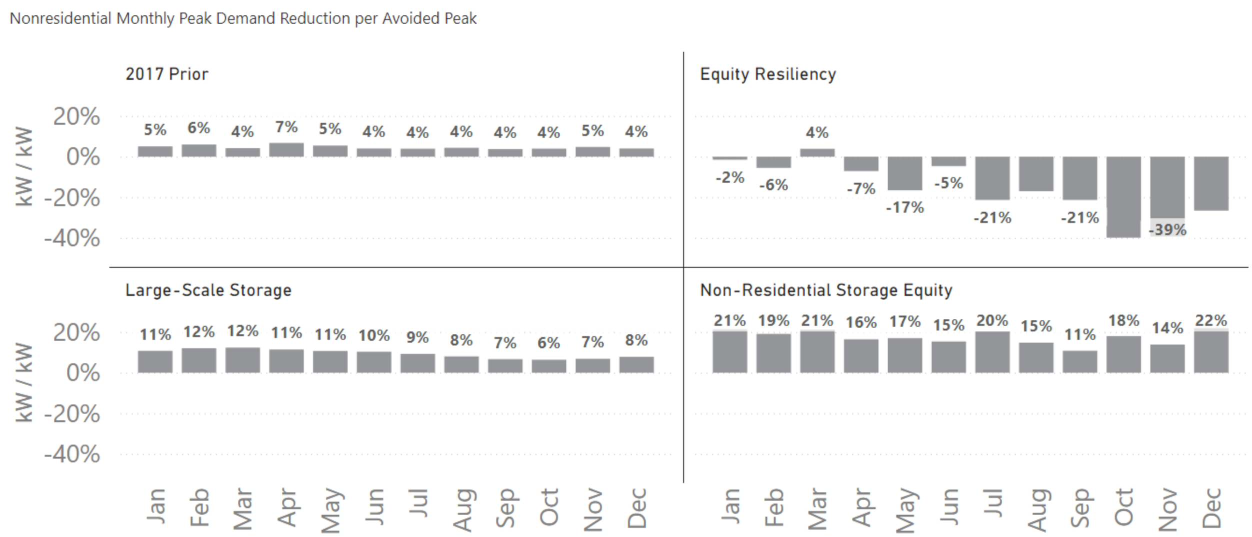


Figure 6-69 summarizes the average impacts across month for each project. The horizontal axis represents the monthly peak demand reduction, as a percentage of rebated capacity, for each system and the vertical axis represents the monthly peak demand reduction for each system relative to their avoided peak demand. Each project budget category is also provided, and the size of the bubble corresponds to the kW capacity of the system.

While the average peak demand reduction is 17% of SGIP rebated capacity across nonresidential systems, the distribution ranges from a peak reduction of 150% of rebated capacity to a peak *increase* of 50% of rebated capacity for a system paid in 2017 or prior.[33] The average monthly peak demand reductions – as a function of peak facility load – is eight percent, with reductions and load increases ranging between +/- 100%.

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33 As of PY 2017, rebated capacity is defined as the average discharge power rating over a two-hour period. Throughout this report, we reference projects by their SGIP rebated capacity with an understanding that inverter sizes can be up to 2x greater than the SGIP rebated capacity value.

FIGURE 6-69: NONRESIDENTIAL PEAK DEMAND IMPACTS BY BUDGET CATEGORY

Overall Storage Dispatch Behavior by Customer Rate Group

The evaluation team also analyzed how storage dispatch behavior differs by customer rate schedule. Verdant employed our distributed energy resource cost-effectiveness analysis tool (DER CAT) to estimate customer bills, leveraging utility rate information alongside AMI hourly-level load data. This sophisticated model incorporates a granular understanding of individual rate charges, demand charges, and variations in time-of-use charges across hours of the day, weekdays, weekends, holidays, and seasonal changes. This information is harnessed to determine the cost of usage for each hour by aligning rate charges with the corresponding date and time of usage, and subsequently aggregating these charges to derive a monthly bill. The inclusion of disaggregated rate charges enables us to discern the various demand charges and energy charges, given the model's comprehensive information into the dynamics of these charges. Below is a summary of SGIP participant rate types for the nonresidential sector, followed by Figure 6-70 which presents the proportion of the different peak periods for the TOU rates for each of the IOUs.

- TOU Energy with Demand Charge
  - This rate group includes customers on a TOU energy rate ($/kWh) as well as a monthly demand charge ($/kW). The monthly demand charge represents the highest rate of power (kW) during any 15-minute interval through each month in the year. This rate group may also contain customers with an additional demand charge incurred during a specific period (on-peak, off-peak and super off-peak) and season (winter or summer).

FIGURE 6-70: DISTRIBUTION OF PEAK PERIODS FOR NONRESIDENTIAL CUSTOMERS (BY IOU)

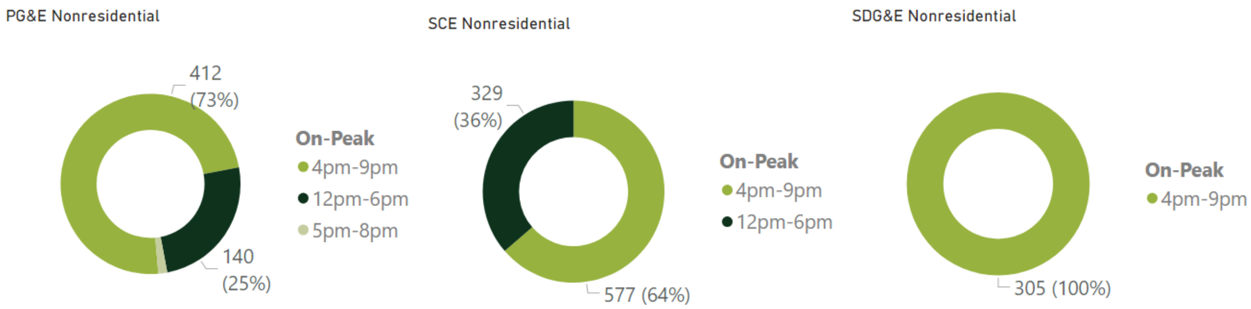
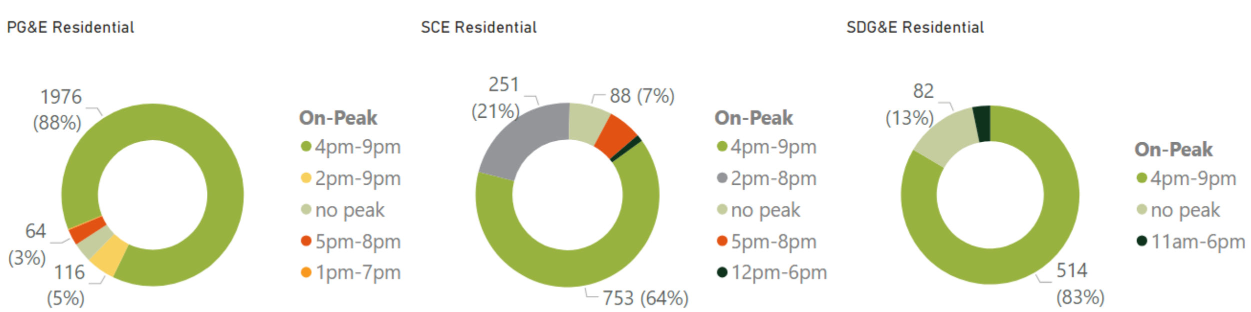


Figure 6-71 presents the proportion of TOU rates versus non-TOU volumetric rates for each of the IOUs in the residential sector. Residential customers with a verified rate schedule were on some type of volumetric or TOU energy rate in 2022:

- Tiered volumetric rate
  - This rate group includes customers on an energy only tariff. They are charged a certain energy rate ($/kWh) throughout a specific tier and rates increase when the customer exceeds the allowance within one tier and move into the next tier. Energy rates are not time-dependent like a TOU rate.
- TOU Energy Only Rate
  - This rate group includes customers on an energy only tariff. They were charged a different energy rate ($/kWh) depending on the period (on-peak, off-peak and super off-peak) and season (winter or summer). Some rates also have a tiered component along with the TOU charge. The on-peak periods vary by IOU and when the customer began on the rate.

FIGURE 6-71: DISTRIBUTION OF TOU VS NON-TOU RATES FOR RESIDENTIAL CUSTOMERS (BY IOU)



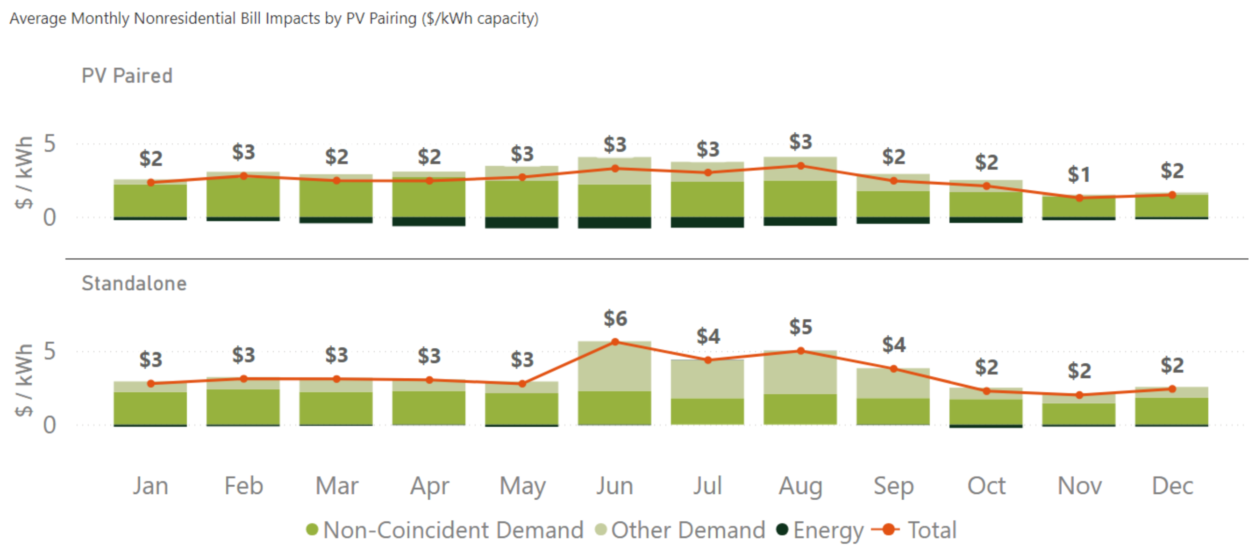
Overall Customer Bill Savings ($/kWh) by Rate Group and Customer Sector

Verdant compared the observed billed energy for each TOU period to baseline billed energy impacts. For customers with demand charges, we further estimated the reduction (or increase) in peak demand at a monthly level and during specific TOU periods to calculate demand savings (or increased cost) based on the customer rate schedule. A customer could realize bill savings if they are arbitraging – discharging throughout on-peak TOU and charging during periods of lower prices – and the price differential between on- and off-peak is sufficient to negate RTE losses. Demand charge savings are realized at the monthly or on-peak period and may be prioritized at the expense of TOU energy arbitrage.

Figure 6-72 presents the results for nonresidential customers by month and presence of on-site PV generation. The bars correspond to the components of the bill; 1) non-coincident demand represents the maximum monthly demand in $/kW, 2) other demand represents the maximum peak and partial-peak (where applicable) demand in $/kW, 3) energy represents the energy component of the bill in $/kWh, and 4) the total is the sum of bill parts. The vertical axis represents the average monthly savings (or increased cost) in dollars, normalized by the capacity kWh of the storage system.

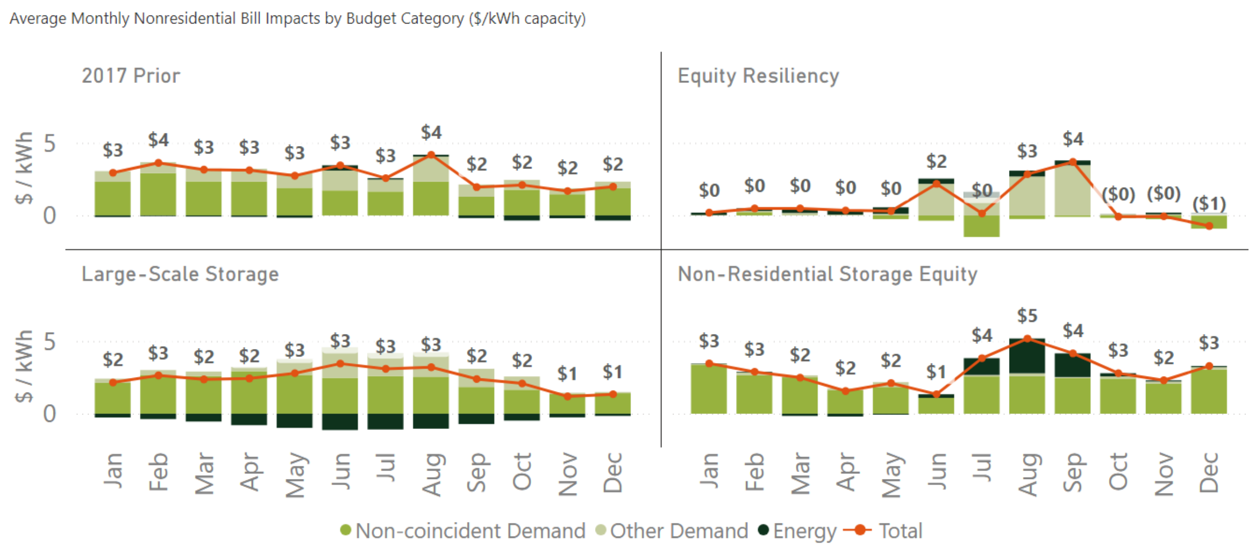
On average, nonresidential storage dispatch behavior allowed customers to realize overall bill savings throughout each month of 2022. Bill savings were greater during summer months for both PV paired and standalone systems. Standalone systems averaged a roughly $6 per kWh of capacity reduction in bills in June, where PV paired systems averaged $3/kWh throughout summer months. Observed differences include, 1) standalone systems reducing peak and partial-peak demand (Other Demand in the chart below) more significantly from June through September than PV paired systems and 2) PV paired systems incurring greater billed energy – represented by the dark green bar going negative. Monthly maximum demand reductions (Non-Coincident demand) are similar across months for both cohorts.

FIGURE 6-72: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND PV PAIRING



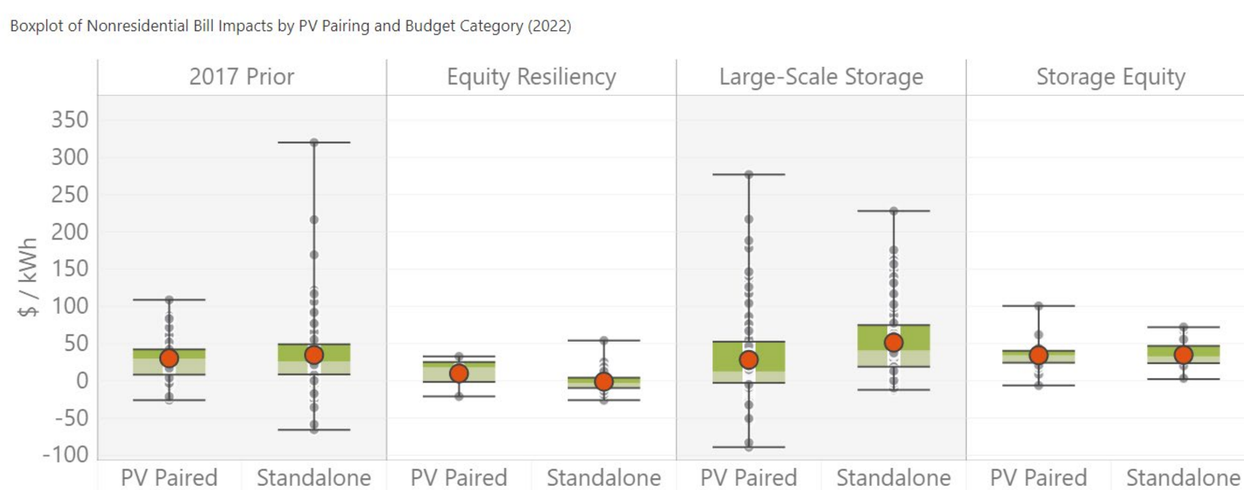
Average monthly bill impacts were also developed by budget category to better capture the different dispatch behaviors observed and discussed above, particularly those found in the ERB. The behavior observed in the five-day load shape presented in Figure 6-66 translates over to the ERB bill impacts in the top right quadrant below. Long duration discharge from 1 pm to 12 am during summer months provide some arbitrage (represented by the positive dark green bar below). Discharging exclusively throughout that period also leads to reductions in peak and partial-peak demand (Other Demand and the light green bars below). While other budget categories realize maximum monthly demand reductions (Non-Coincident Demand), ERB projects incur increases on that component of the bill. Charging overnight typically leads to a new maximum, which translates over to the observed bill increase on the maximum/non-coincident peak (Non-Coincident Demand and the green bar).

FIGURE 6-73: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND BUDGET CATEGORY



Annual project bill impacts (and variance) are displayed below by budget category and on-site PV generation. Monthly impacts have been summed to represent total $ savings (+) or $ incurred (-) in 2022 per kWh capacity, based on observed system operations. Despite several individual project outliers with annual bill savings extending above $100/kwh, average savings range from over $50/kWh for standalone large-scale projects to a slight increase in bills for standalone ERB ($1.20/kWh). Note that the greater average bill savings from standalone systems compared to PV-paired shown in Figure 6-74 comes mainly from large-scale projects.

FIGURE 6-74: DISTRIBUTION OF NONRESIDENTIAL OVERALL CUSTOMER BILL IMPACTS ($/KWH)



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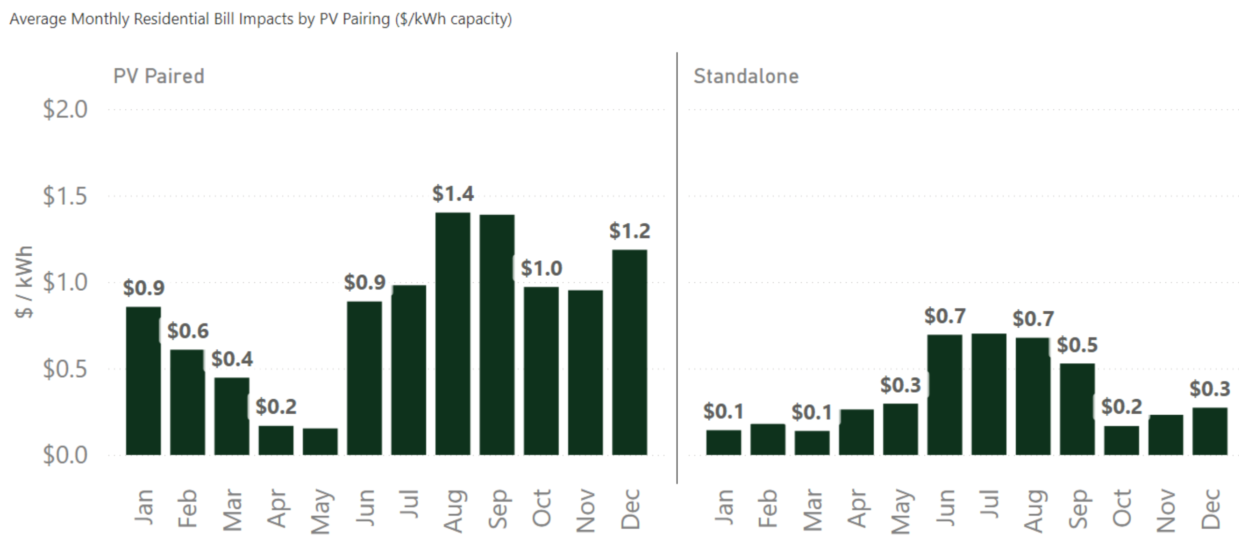
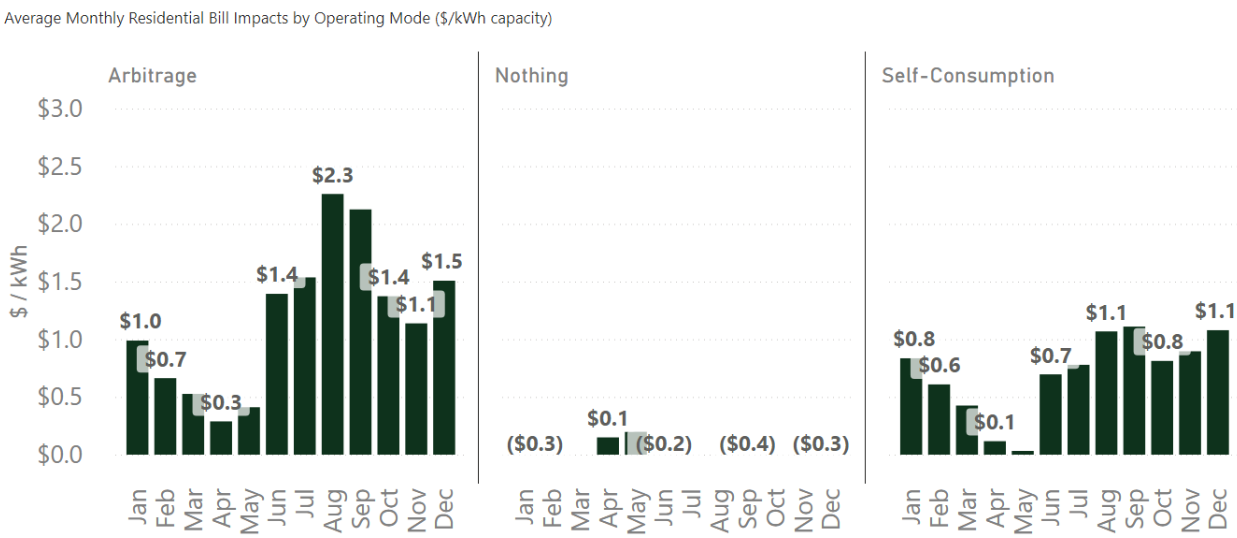
Monthly residential bill impacts by standalone and PV pairing are summarized below in Figure 6-75. We observe monthly bill savings for residential customers ranging from as high as $1.40/kWh in August-September for paired systems, to as low as $0.20/kWh for the same systems in May of 2022. PV Paired systems are almost exclusively charging from on-site solar – when utilized – and discharging on-peak exclusively for TOU arbitrage or discharging to zero out delivered load during the on-peak period and thereafter. Standalone systems are discharging on-peak and charging overnight, most prominently after midnight.

FIGURE 6-75: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND PV PAIRING



Average monthly bill impacts by operating mode are presented below. Idle systems unsurprisingly incur small bill increases due to under-utilization and RTE losses. Time-of-Use arbitrage and self-consumption provide billed savings across each month of 2022, but systems performing arbitrage realize the greatest savings, particularly throughout August and September, where savings exceed $2/kWh on average. Spring months like April and May exhibit the least savings on average. Throughout those months, many customers have not transitioned to higher on-peak energy rates, and greater on-/off-peak price differentials. Billed rates, combined with significant on-site solar generation with temperatures that preclude A/C and other high demand end uses, allow customers to arbitrage or self-consume at lower utilization. If the system is zeroing out delivered load, and is not exporting, billed savings for these months could be less relative to a baseline (or counterfactual) of no storage.

FIGURE 6-76: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND OPERATING MODE



The next two figures exhibit average monthly bill impacts by PV pairing and IOU, followed by budget category. Bill impacts for systems receiving electric service from PG&E vary throughout the year, whereas most savings for SDG&E systems are realized throughout June to October inclusive. PV paired SCE systems exhibit the greatest savings throughout the year, particularly in August and September, due to having significantly higher on-/off peak differentials than SDG&E and especially PG&E (apart from PG&E's EV-2A rate).

FIGURE 6-77: RESIDENTIAL CUSTOMER BILL IMPACTS ($/KWH) BY MONTH, PV PAIRING AND IOU

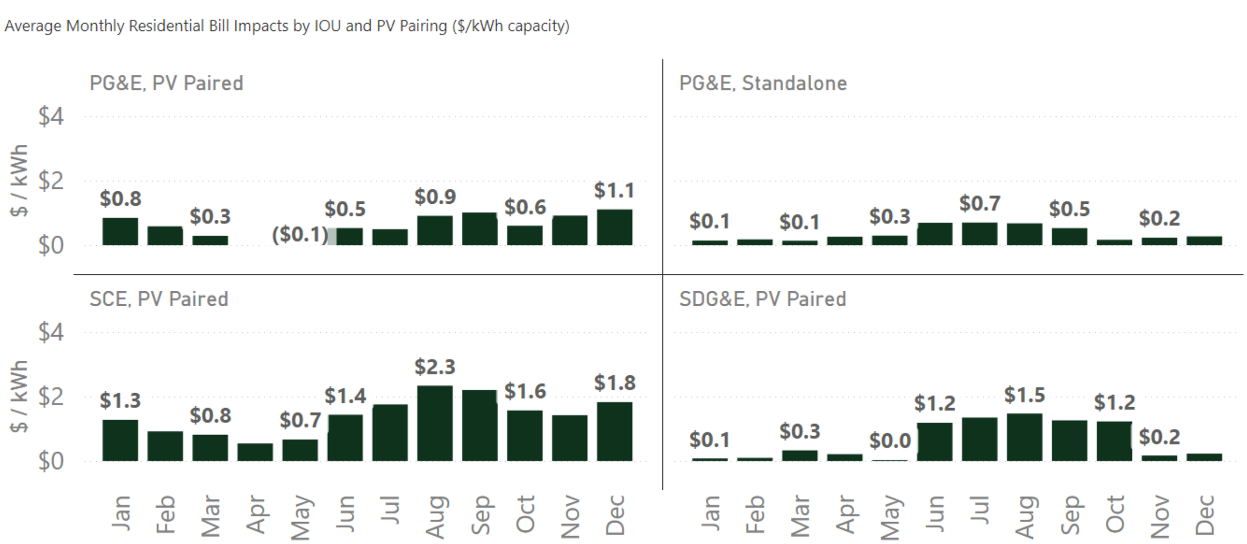


FIGURE 6-78: RESIDENTIAL CUSTOMER BILL IMPACTS ($/KWH) BY MONTH AND BUDGET CATEGORY

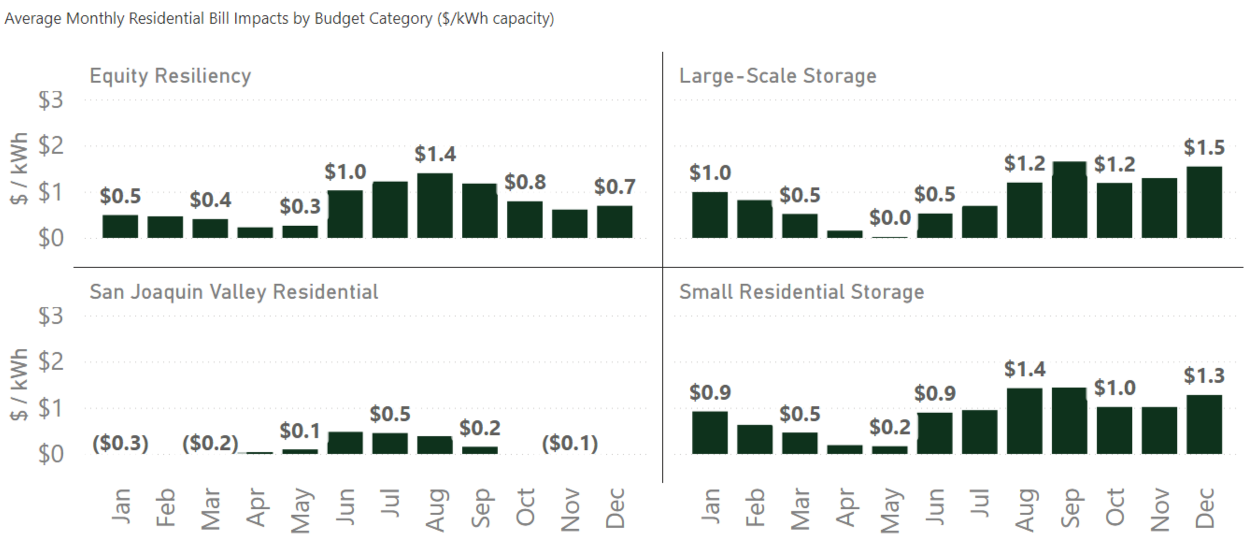


FIGURE 6-79: DISTRIBUTION OF RESIDENTIAL OVERALL CUSTOMER BILL IMPACTS BY OPERATION ($/KWH)

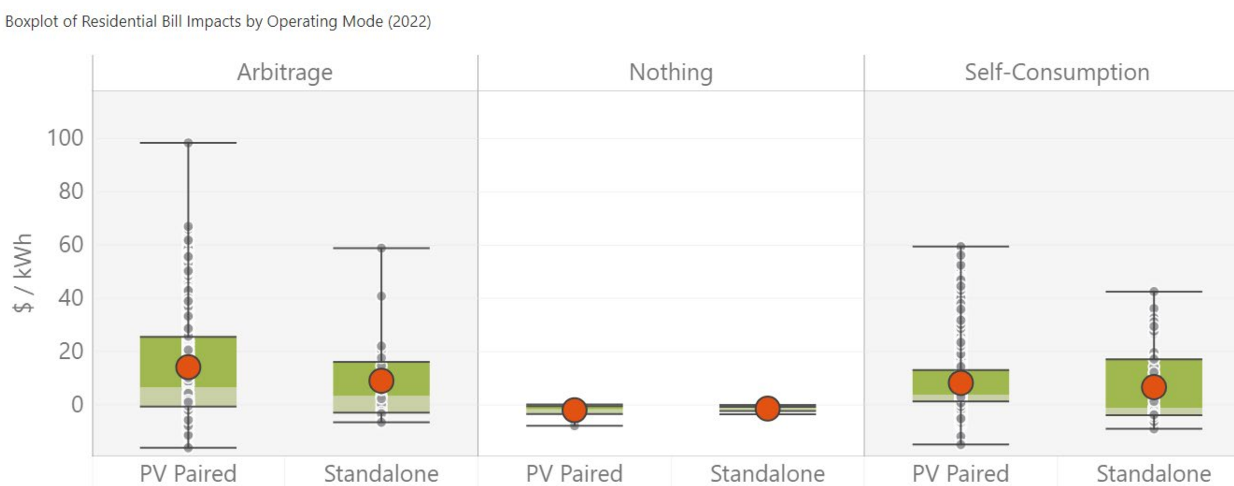
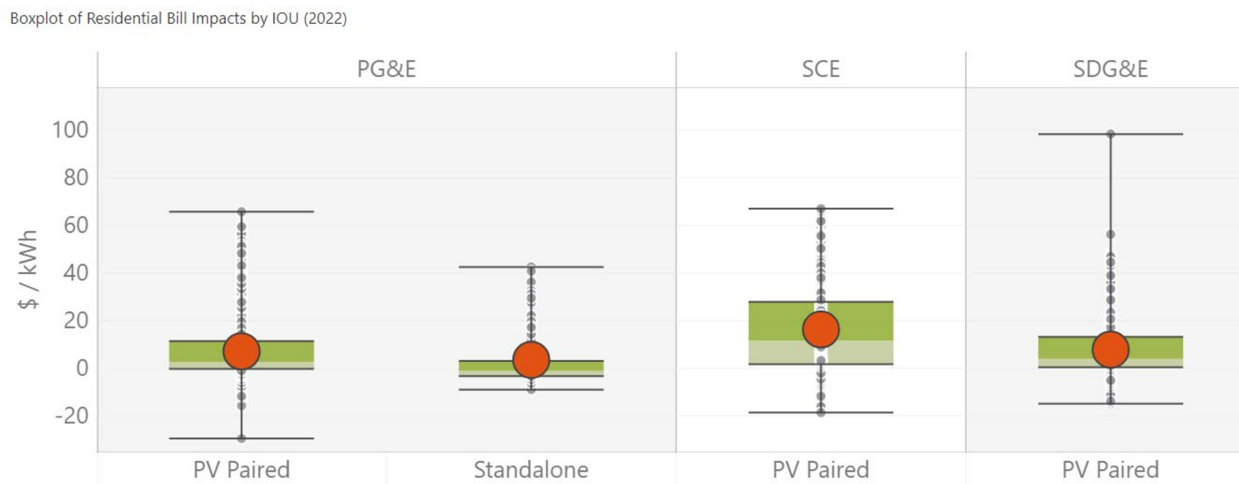


FIGURE 6-80: DISTRIBUTION OF RESIDENTIAL OVERALL CUSTOMER BILL IMPACTS BY IOU ($/KWH)



6.2.2 Generation

The operational characteristics of the several generation technologies influence their impacts on customer operations and energy bills. Wind turbines and pressure reduction turbines differ from the others due to the nature of their energy inputs. The supply of wind energy varies with weather, while the supply of steam may vary with facility production levels. Generation technologies relying on gaseous fuels are designed to operate with relatively high capacity factor, and thus offer more potential for consistently impacting noncoincident facility peak demand levels that factor into the calculation of billed demand charges on electricity bills. The impacts of generation systems on customer noncoincident peak demand and electricity exports are presented below.

Customer Noncoincident Peak Demand

SGIP projects impact customer demand in addition to the system (IOU or CAISO) coincident peak demand. It is not always the case that a customer's peak demand falls on the CAISO or IOU peak load hour. The peak customer demand during any stated period is called the customer noncoincident peak (NCP) demand. The impact on a customer's annual peak demand is an important element of the total impact an SGIP system has on a customer's load throughout the year. The demand portion of customer bills is based on the monthly peak kW. Thus, in addition to the reduction in annual peak demand, the monthly demand reduction illustrates how SGIP impacts customer electricity costs.

Approach for Customer Noncoincident Peak Demand Impacts

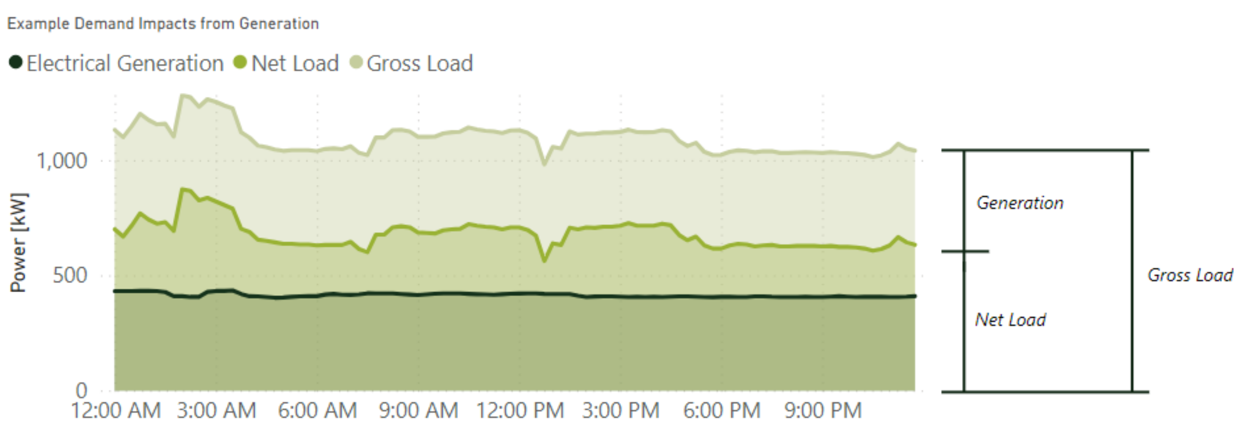
To analyze the impact of SGIP on customer NCP demand, the available utility AMI load data and the generation data are aligned on an hourly basis. The gross demand without the presence of the SGIP generation is then calculated as:[34]

$$\boldsymbol{Gross\ Load\ (\overline{kW}) = Metered\ Load + Generation - Exported} \quad \textbf{EQUATION 6-9}$$

$$\boldsymbol{Net\ Load\ (\overline{kW}) = Metered\ Load} \quad \textbf{EQUATION 6-10}$$

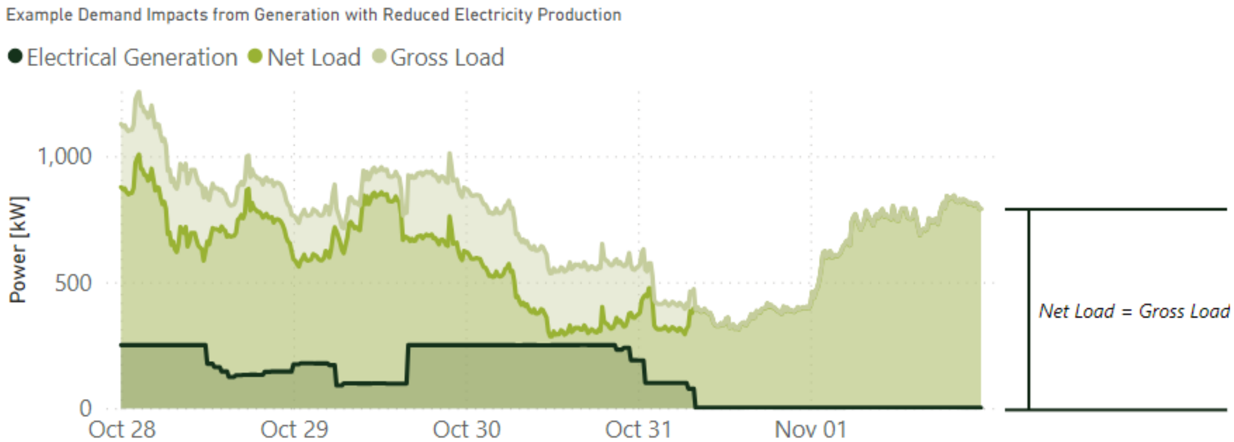
The potential impact of SGIP generators on gross and net load can be seen graphically in the following figures. Figure 6-81 shows an example of how metered NCP customer demand, represented by net load, is reduced by SGIP generation. During 2022, the maximum electrical generation brought the maximum gross peak down, on average, by as much as 96% of rebated capacity. Figure 6-82 illustrates the impact an SGIP generator outage has on NCP customer demand. Depending on the customer load profile, net load during a generator outage or period of reduced electrical production may set the monthly or annual peak demand.

FIGURE 6-81: EXAMPLE DEMAND IMPACTS FROM GENERATOR



[34] For this analysis, demand is calculated as the average power draw within a one-hour period. This is an approximate calculation, as demand is measured in 15-minute intervals and may differ from the hourly average.

FIGURE 6-82: EXAMPLE DEMAND IMPACTS FROM GENERATOR WITH REDUCED ELECTRICITY PRODUCTION



Average NCP Customer Demand Impacts

The weighted average impacts of generation technologies on NCP customer monthly maximum demand are shown below in Figure 6-83 as a proportion of rebated capacity. Electric fuel cell projects, on average, provided customer monthly peak demand savings equal to 68% of rebated capacity; a customer with a 100 kW fuel cell would see a reduction of their net load of about 68 kW during their monthly peak load hours. Gas turbines, on average, would reduce customer load by 81% of rebated capacity, and wind turbines were found to reduce the noncoincident peak demand by 96% of rebated capacity. While we typically see the highest variability in generation with wind turbines, the monthly peak load for these facilities with wind turbines often occurred during early morning hours, which also happen to be the time when wind generation is the highest. These results are notable, given the variable nature of wind turbine generators as compared to other generation technologies. The four projects contributing metered data to that result appear to be exceptional examples of effective pairing of site-specific wind resource and customer electric load characteristics. The need to consider this pairing distinguishes wind turbine generators from the other generation technologies and may help to explain SGIP participation levels for wind projects.

FIGURE 6-83: OBSERVED AVERAGE MONTHLY NCP IMPACTS AS PERCENT OF REBATED CAPACITY

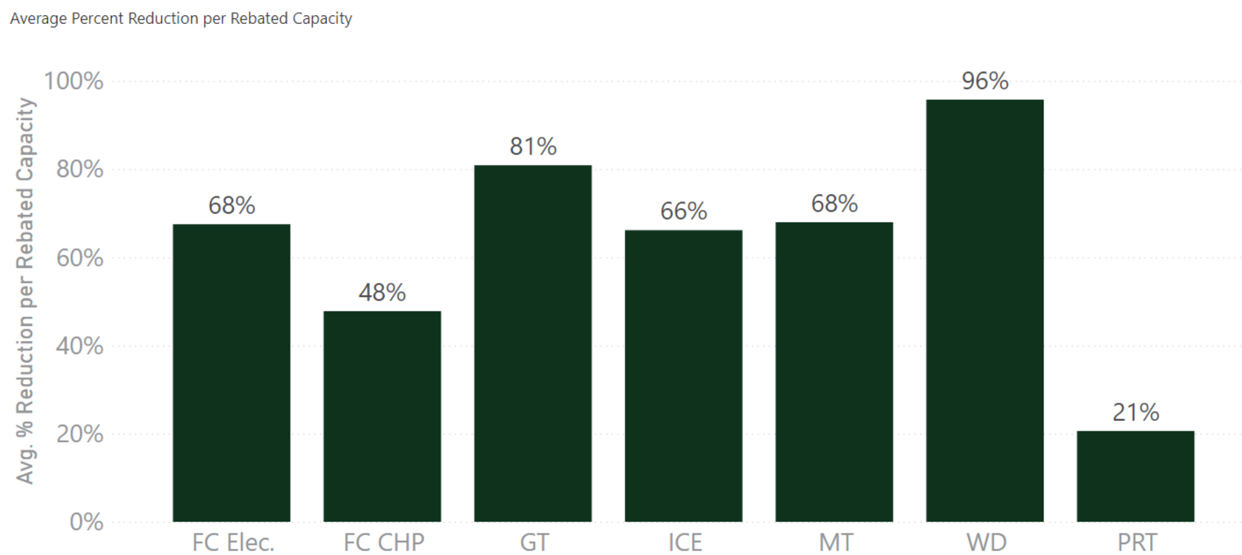


Figure 6-84 shows the same information at the monthly level. Many generation technologies don't show much variation in their noncoincident peak demand impacts by month. However, microtubines, internal combustion engines, and CHP fuel cells show the greatest monthly variations, as did pressure reduction turbines, although there are only a few of these projects in the program. While it's difficult to tell the exact reason for variations in operation, many of these variations appear to be due more to differences in site-specific operation than technology-specific use cases. Although generation systems generally provide a baseload, technologies like microturbines and internal combustion engines are easier to ramp up and down than fuel cells, and therefore do have the ability to be shut down or run at a reduced capacity when not needed. Seasonal variations could also be due to unexpected disruptions in facility or SGIP system operations.

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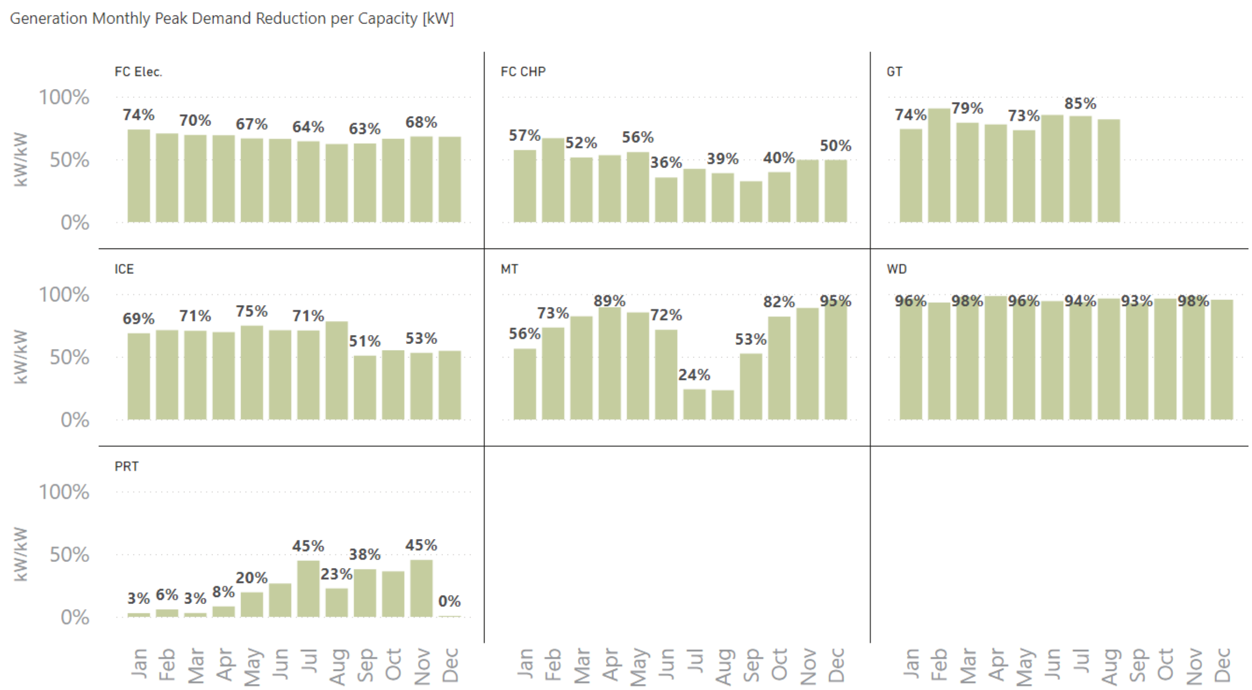
FIGURE 6-84: OBSERVED MONTHLY NCP IMPACTS AS PERCENT OF REBATED CAPACITY



Generation Export

Electricity generation systems are generally designed to be base loaded, meaning they are operated to generate enough electricity to cover the base load needs of a customer. Since at least PY 2011, the SGIP Program Handbook allows SGIP incentivized systems to export a maximum of 25% of their onsite consumption to the grid, on an annual basis. During 2018 and 2019, about 35% of SGIP systems were found to be exporting energy to the grid. These customers, on average, exported just over 10% of their net load. During 2021-2022, the percentage of sites that were found to be exporting to the grid increased closer to 45%. Figure 6-85 highlights a shift in percent of load exported between the 2018-2019 evaluation period and the 2021-2022 evaluation period. In particular, all-electric fuel cells appear to be exporting a larger percentage of energy than they had in previous years. There are two potential drivers of this; many of the customers installing all-electric fuel cells appear to be on power purchase agreement (PPA) contracts, requiring them to purchase 100% of the electricity generated from the systems, even if they are not utilizing all the energy.[35] California saw significant energy constraints during 2020, and in response,

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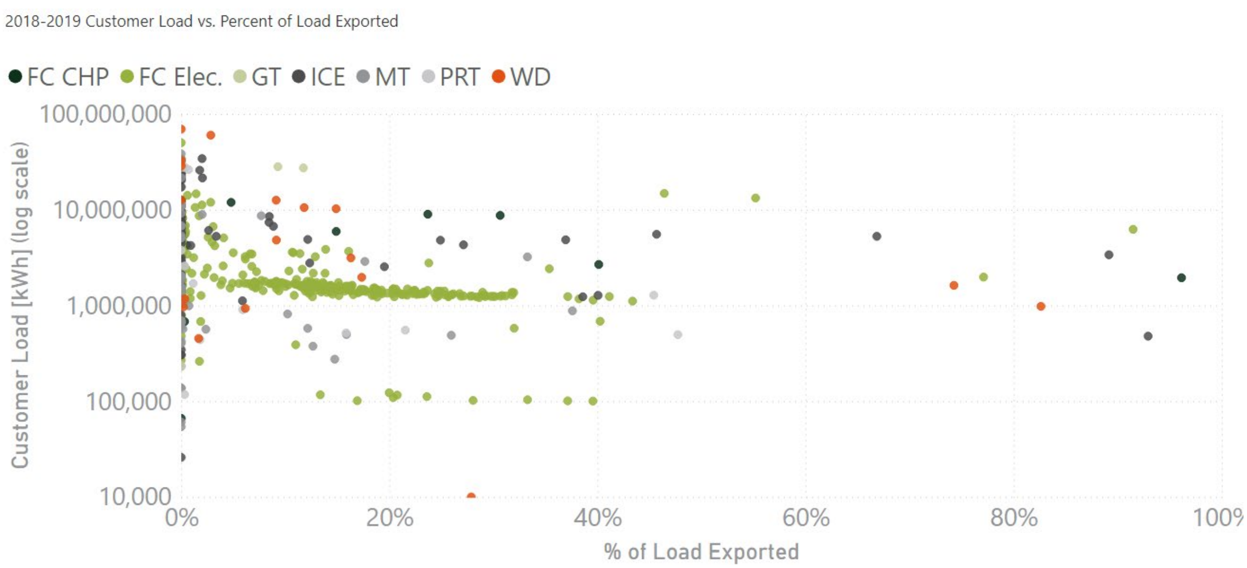
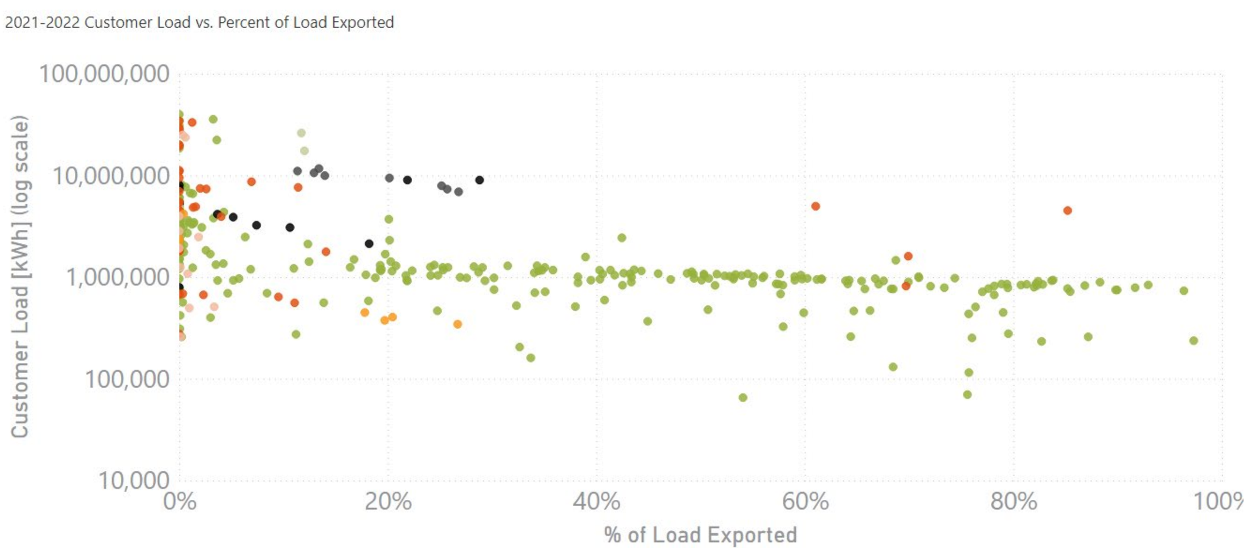
[35] Bloom Energy's 2018 July S-1 Statement states "… The end-customer is required to purchase all of the electricity generated by the Energy Servers for the duration of the offtake agreement…" Page 89. https://d18rn0p25nwr6d.cloudfront.net/CIK-0001664703/f332ae61-2c3b-4eff-92b4-8565d1ea9781.pdf. Accessed 10/24/2023.

Bloom Energy ran an initiative to export significant energy to help relieve the strain on the grid using combustion-free, fuel flexible technologies.[36] It is possible that since this initiative, many Bloom customers have continued to export all unused excess energy.

FIGURE 6-85: CUSTOMER LOAD VS PERCENT OF LOAD EXPORTED ACROSS 2018-2019 AND 2021-2022





[36] *Local Ordinances Exceeding the 2019 Energy Code. San Jose – 2019 2 Public Comments 3.* Docket Number 19-BSTD-06. Docket Date: 02/12/2021. Page 4. https://efiling.energy.ca.gov/GetDocument.aspx?tn=236754-10&DocumentContentId=69797. Accessed 03/20/2024.

Natural Gas Impacts

The use of natural gas fuel by early SGIP systems results in increased pipeline transport of natural gas in California. However, the useful recovery of heat that displaces natural gas boilers reduces the pipeline transport of natural gas. Figure 6-86 below summarizes the project-level observed net impacts on natural gas, displayed as thousand therms per rebated kW. Based on the metered data, these projects result in a natural gas increase around 300 therms per rebated kW, so a 500 kW generation system would increase natural gas usage by 150 thousand therms. There were three renewably fueled projects that also recovered heat, which resulted in reduced natural gas use, as the heat recovery displaces natural gas that would otherwise be used for boilers.

FIGURE 6-86: OBSERVED NATURAL GAS IMPACTS

6.3 CAISO AND IOU SYSTEM IMPACTS

By generating or discharging during CAISO and IOU peak hours, SGIP project hosts allow their electric utility to avoid the purchase of high-cost wholesale energy. At the same time, the electric utility reduces its transmission and distribution losses during hours of high system congestion. And during extreme events, generating/discharging can even help avoid rolling blackouts. Ideally, SGIP system hosts are generating at full capacity and avoiding system maintenance during peak hours and thus contributing the greatest possible demand impacts. However, these CAISO or IOU peak hours do not necessarily occur when an SGIP system host may want to be generating, therefore a host may not always operate their SGIP system optimally during the grid peak hours.

This section examines generation during CAISO and IOU annual peak “gross” load and “net” load hours as well as their top 100 hours. Table 6-2 lists hours and magnitudes of CAISO and IOU peak demands during 2022. The gross peak CAISO hour occurred September 6, 2022, beginning at 4PM local time, while the net peak hour occurred three hours later the previous day. We show impacts related to both gross and net peak hours.[37]

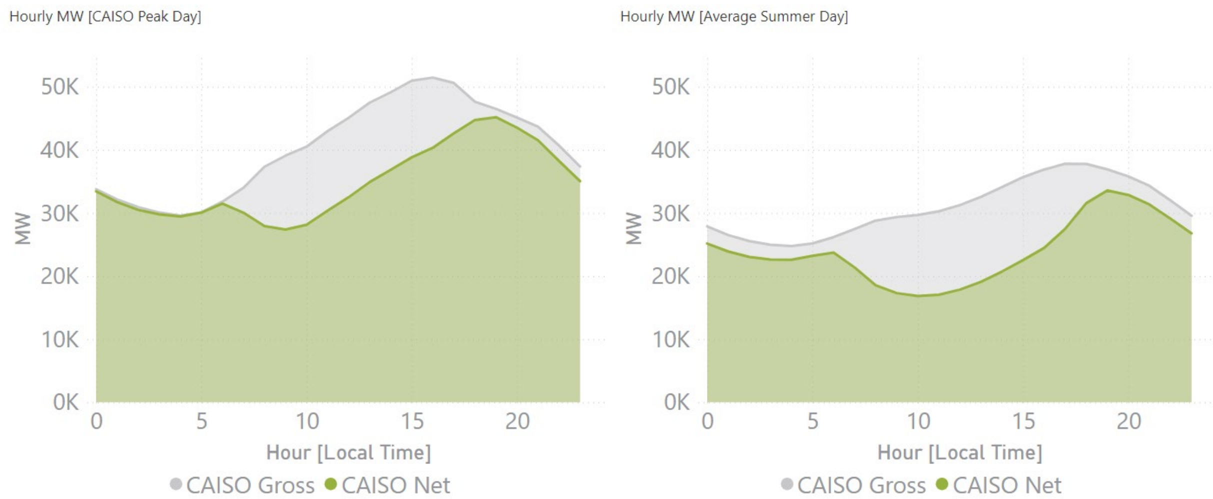
TABLE 6-2: 2022 CAISO AND IOU PEAK HOURS AND DEMAND [MW]

Peak Period	Peak Demand [MW]	Date	Hour [Local Time]
CAISO - Gross	51,472	September 6th	4pm-5pm
CAISO – Net	45,389	September 5th	7pm-8pm
PG&E	22,371	September 6th	4pm-5pm
SCE	24,355	September 7th	3pm-4pm
SDG&E	4,633	September 7th	4pm-5pm

Figure 6-87 highlights the differences between the CAISO gross and CAISO net loads. The right figure represents an average summer day where there is a slight early morning ramp, followed by a drop in net load throughout the day and an early evening ramp. The graphic also shows the CAISO gross and net load on the gross peak day in 2022. On that day, as solar generation waned in the late afternoon, demand was only slowly declining. As a result, the net peak occurred roughly three hours after the gross peak. The net peak on this day was the 2nd highest in 2022. When examining other days within the summer, a similar pattern is revealed. The net peak typically occurs 1 to 3 hours after the gross peak.

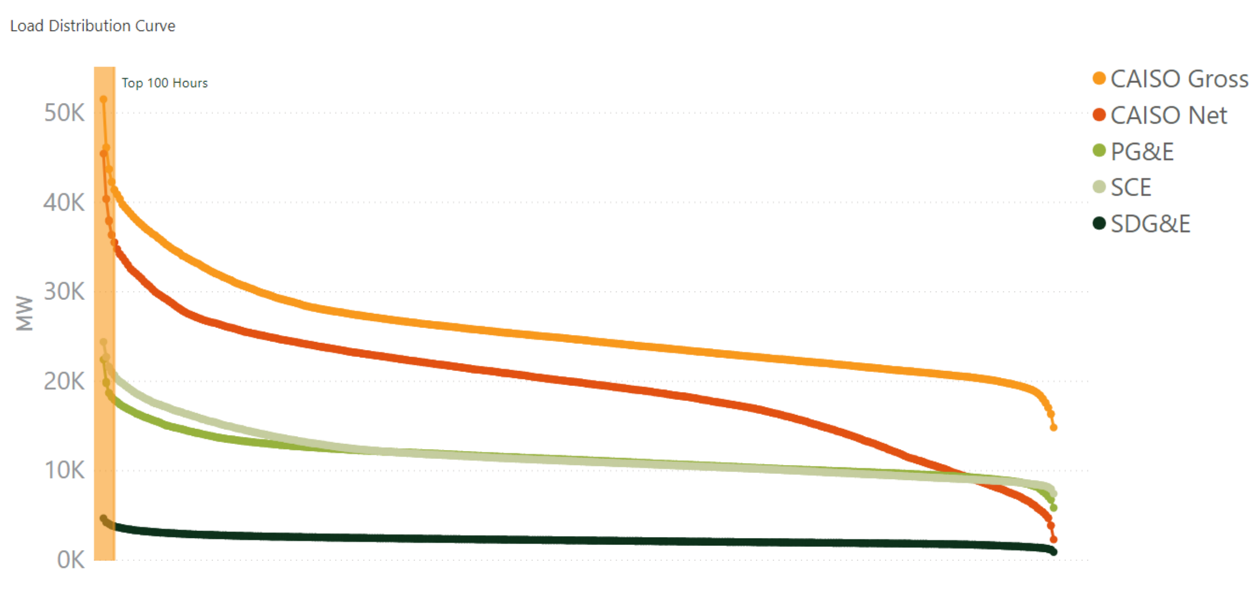
[37] The gross load is equal to total load at the transmission level and is equal to (net) customer meter data plus losses. Gross load therefore includes the impact of customer-sited generation and batteries; it comprises the back of the duck in CAISO’s famous duck curve. Net load subtracts grid-scale solar and wind generation and comprises the belly of the duck. While gross load is the amount that must be generated or imported to meet customer demand, the net load is a better indicator of both energy prices and grid stress than gross load.

FIGURE 6-87: CAISO GROSS AND NET LOAD FOR AVERAGE SUMMER DAY VS CAISO PEAK DAY (9/06/2022)



CAISO and IOU annual peak and net peak hour coincident generation is a snapshot of beneficial program impacts. Analyzing the top 100 peak hours results in a more robust measure of impacts during CAISO and IOU peak grid loads. Representing just 1.1% of all the hours in a year, the top 100 peak hours capture the steepest part of load distribution curves. Figure 6-88 shows the 2022 CAISO and IOU load distribution curves and indicates the 100-hour mark as the solid orange bar on the left side.

FIGURE 6-88: LOAD DISTRIBUTION CURVES



The distributions of the top 100 hours over a year differ between CAISO and the three IOUs, and from year to year. While generally mid-to-late summer afternoon occurrences, a top-100 hour can occur as early as June, but during 2022, most of these hours occurred during August and September. Figure 6-89 displays the distribution of the top 100 peak hours by month. The majority of the top 100 hours occurred in September across all utilities. In 2022, PG&E saw the earliest peak hours, occurring in June.

FIGURE 6-89: TOP 100 HOUR DISTRIBUTIONS BY MONTH

Top 100 Hour Distributions by Month

Year	June	July	August	September
2022				
CAISO Gross	1	1	30	68
CAISO Net	4	4	32	60
PG&E	13	6	29	52
SCE			34	66
SDG&E			19	81

6.3.1 Energy Storage

As a load shifting technology, BTM storage can provide grid benefits if the timing and magnitude of storage discharge aligns with periods of grid stress and coincident peak demand and system charging is left to less critical times. As detailed above, SGIP nonresidential storage systems are generally being utilized to reduce non-coincident monthly peak demand, but also TOU energy arbitrage. Systems designed for demand charge reductions may incur increases on the energy component of their bill, but demand reduction savings lead to a net decrease in bills overall. We also observe nonresidential systems performing TOU arbitrage exclusively, and subsequent charging leads to increases in non-coincident peak demand. Residential storage systems are being utilized for TOU arbitrage and self-consumption – where the battery is discharged to minimize grid imports throughout the on-peak period as well as after. Residential systems are realizing savings on the energy component of their bill, especially during summer months when on-peak and off-peak price differentials are high, and systems are utilized more often. Both residential and nonresidential systems with on-site PV generators are charging almost exclusively during early PV generating hours and discharging later in the day.

The timing of charge and discharge not only directly impacts customer bills, but it can also have an impact on grid services. Benefits to these systems are potentially due to participation in demand response programs (both system-level/localized and real-time/day-ahead), enrollment in IOU tariffs with TOU rates or include peak energy pricing like Critical Peak Pricing (CPP) or Peak Day Pricing (PDP). Some benefits may just be coincidental. Storage project operators and host customers may not be aware of system or utility level peak hours unless they are enrolled in a demand response program or retail rate where a price signal (or incentive) is generated to shift or reduce demand. Customers understand their facility operations and bill rate structure, but grid level demand may not be in their purview.

Storage discharge behavior that is coincident with critical system hours can provide additional benefits beyond customer-specific ones. These benefits include avoided generation capacity costs and transmission and distribution costs. The evaluation team assessed this potential benefit by quantifying the storage dispatch from the sample of nonresidential and residential systems throughout the top 100 gross and net peak demand hours in 2022 for the CAISO system, along with IOU-specific peaks.

CAISO System Impacts

Verdant examined how SGIP storage systems were operating throughout periods when the grid may be capacity constrained. We analyzed the magnitude of residential and nonresidential storage system charge and discharge during some of the peak system-level hours. To evaluate CAISO system-level impacts, we reviewed both the top gross and net load hours in 2021 and 2022. On any given day, CAISO load is comprised of a variety of energy supply sources, including natural gas power plants, large hydro, imported power and grid-level renewables like wind and solar. The availability of renewable energy throughout the day allows grid operators to use less fossil fuel-based sources. However, the intermittent nature of these renewables is disruptive. The correct timing of energy storage discharge and charge can help ease that transition and alleviate that disruption.

Intermittency is particularly troublesome with grid-scale solar PV which, like on-site rooftop solar, generates only when the sun is shining. Billed on-peak periods, like from 4 pm – 9 pm, provide price signals to customers to reduce, avoid, or shift their consumption during those periods, but that five-hour period is still broad. Most residential systems are two-to-three-hour batteries, so if a system fully discharges during the early on-peak period (4 pm to 6 pm), state-of-charge will be insufficient to continue discharging throughout the latter hours of the on-peak period. Discharging a few hours later at full capacity or over a longer duration could provide more utility benefits and GHG reductions – as grid-level net load ramps – with bill savings largely unchanged. CAISO gross load (including renewables) peaked on 9/5/2024 during the 4 pm hour, while the net peak occurred over two hours later. As a result, we examined storage performance at two peak periods: the gross peak, when overall demand is at its highest and all available electricity supply sources reach their maximum generation (MW), and the net peak, when overall demand minus renewable supply sources is reaching peak generation.

For each customer sector, we evaluated the average kWh discharge per kW capacity throughout all CAISO gross and net hours throughout 2022. Figure 6-90 and Figure 6-91 present those results for the nonresidential sector. On the vertical axis is the average discharge (+) and charge (-) kWh normalized by kW capacity. The secondary vertical axis provides the average hourly CAISO MW load, and the horizontal axis ranks the gross and net CAISO hours from highest to lowest throughout the year. While it's difficult to tease out individual hourly impacts from a figure exhibiting 8,760 of them, general patterns are observable. Greater average hourly discharge occurs during higher ranked CAISO gross and net hours compared to lower load hours. This behavior supports the distributions of discharge by time of day presented in Section 6.2.1 where a combination of TOU arbitrage and demand charge reductions were observed across the fleet of nonresidential storage systems. Greater magnitudes of charging occur during the lowest Net CAISO peak hours because that load represents hours when grid-scale renewables like solar PV are generating a significant mix of California's energy portfolio – times when nonresidential systems paired with on-site PV are also charging from that sun fueled generation source.

FIGURE 6-90: HOURLY STORAGE KWH PER KW – 2022 CAISO GROSS LOAD HOURS FOR NONRESIDENTIAL

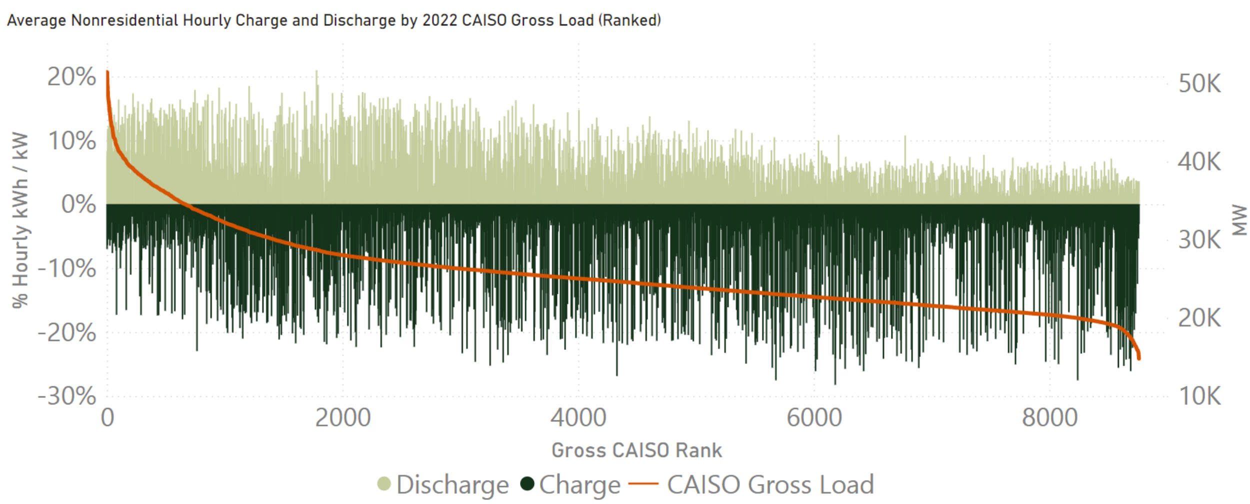
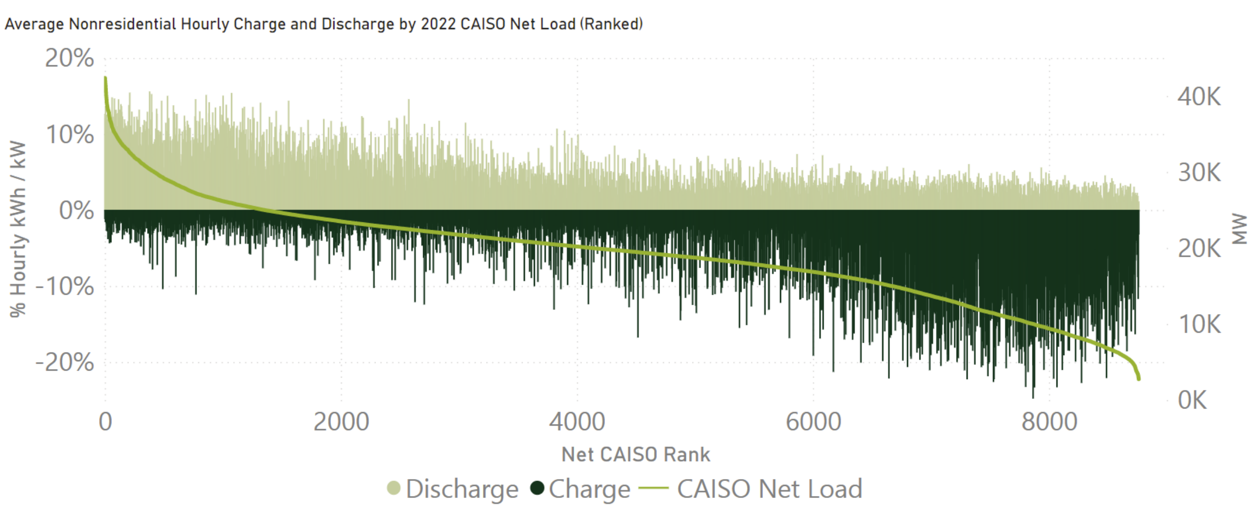


FIGURE 6-91: HOURLY STORAGE KWH PER KW – 2022 CAISO NET HOURS FOR NONRESIDENTIAL



Residential systems exhibit a similar trend in average hourly charge and discharge during ranked gross CAISO hours – greater discharge magnitudes during peak hours relative to lower demand hours, but still significant inter-hour charging and discharging throughout the year. More evident is the negative correlation between discharge and charge magnitudes when compared against net CAISO hours (Figure 6-93). We observe greater magnitudes of inter-hour discharge than charge during peak net CAISO hours – when residential systems are almost exclusively discharging for self-consumption or arbitrage – and greater inter-hour charging when CAISO net loads are lower – when residential systems are charging systems from on-site PV.

FIGURE 6-92: HOURLY STORAGE KWH PER KW – 2022 CAISO GROSS LOAD HOURS FOR RESIDENTIAL

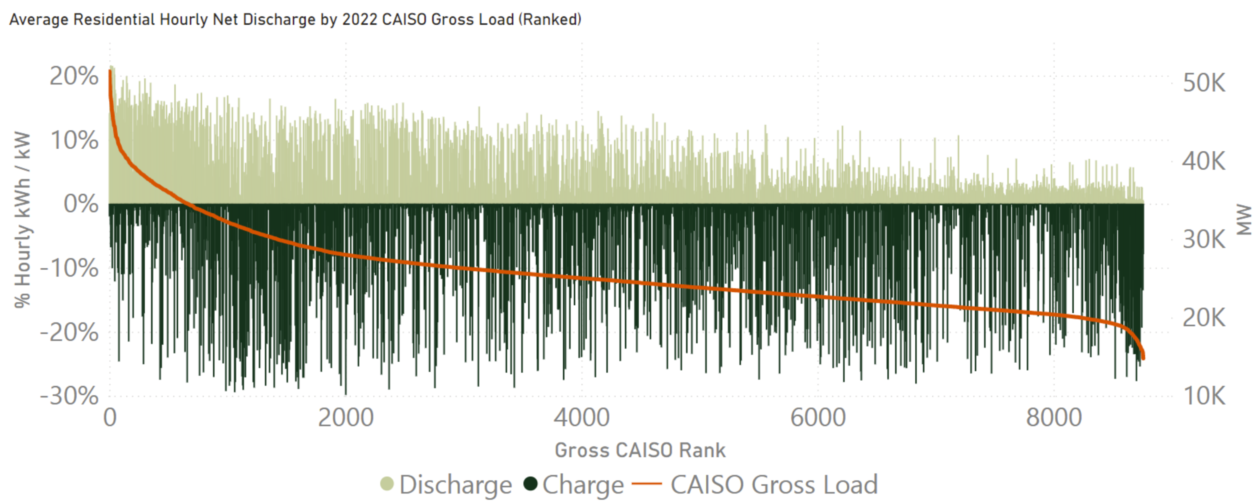
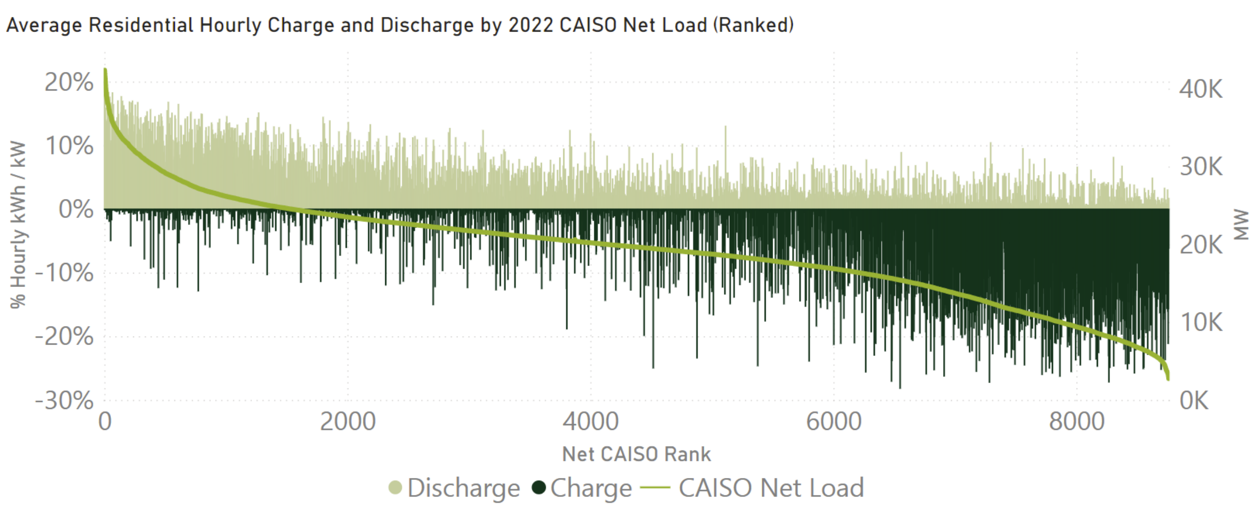


FIGURE 6-93: HOURLY STORAGE KWH PER KW – 2022 CAISO NET HOURS FOR RESIDENTIAL



One important observation to note is the slope of the line that follows the highest to lowest load hours for each of the 8,760 hours throughout 2022 – in particular, the steep observed drop off in gross and net CAISO load from peak hours to subsequent ones. Those peak hours coincided with a rare weather event known as a "heat dome", which occurred across multiple days and delivered unrelenting heat, which put significant stress on generation capacity, and transmission and distribution systems in California. System load peaks are evident in Figure 6-94 where hourly gross and net CAISO load are plotted throughout 2021 and 2022. Also provided are the gross and net load at the 99th percentile across both years. The heat dome event is evident in the figure, with gross and net peaks extending well above the 99th percentile of observed peaks in 2021 and 2022, illustrating the steepness of the load curve at the top end. What follows is the observed performance of SGIP incentivized systems either throughout the Top 100 CAISO net and gross load hours (most of which occurred during that week) or performance during specific days and hours of the heat dome event.

FIGURE 6-94: CAISO HOURLY GROSS AND NET LOAD THROUGHOUT 2021 AND 2022

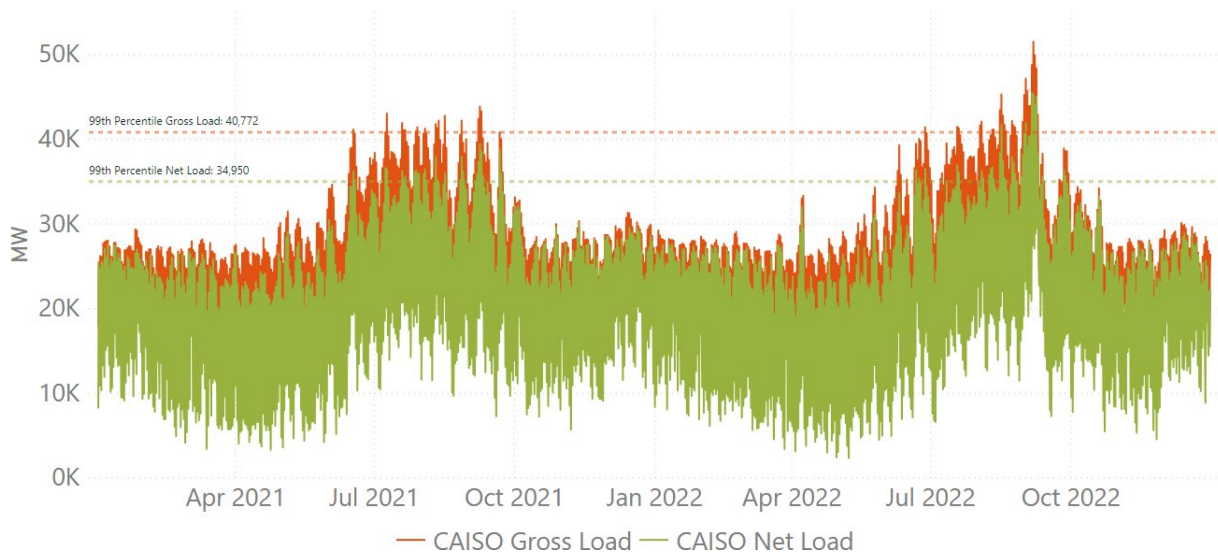


Figure 6-95 and Figure 6-96 below present the average kWh discharge and charge per kW capacity for nonresidential systems during each of the top 100 CAISO gross and net hours in 2022, respectively. Given some of the significant observed performance differences for standalone and PV paired systems, figures have been further segmented by that classification. Both figures show nonresidential systems actively discharging or charging throughout all gross and net peak hours at differing magnitudes. When the magnitude of hourly charge is greater than the hourly discharge, then the net discharge is negative. This would signify that, on average, the fleet of nonresidential systems is charging during that hour (and vice versa). As mentioned previously, net peak hours occur later in the day than top gross peak hours. Some of those later hours correspond to periods when nonresidential systems have already charged from paired PV earlier in the day and are discharging exclusively on peak. This is one of the reasons why charging magnitudes are much lower across top net peak hours for systems paired with PV. Also evident, is the much greater discharge observed with standalone nonresidential systems, relative to charge during the same hours.

FIGURE 6-95: HOURLY STORAGE KWH PER KW – CAISO TOP GROSS 100 HOURS FOR NONRESIDENTIAL

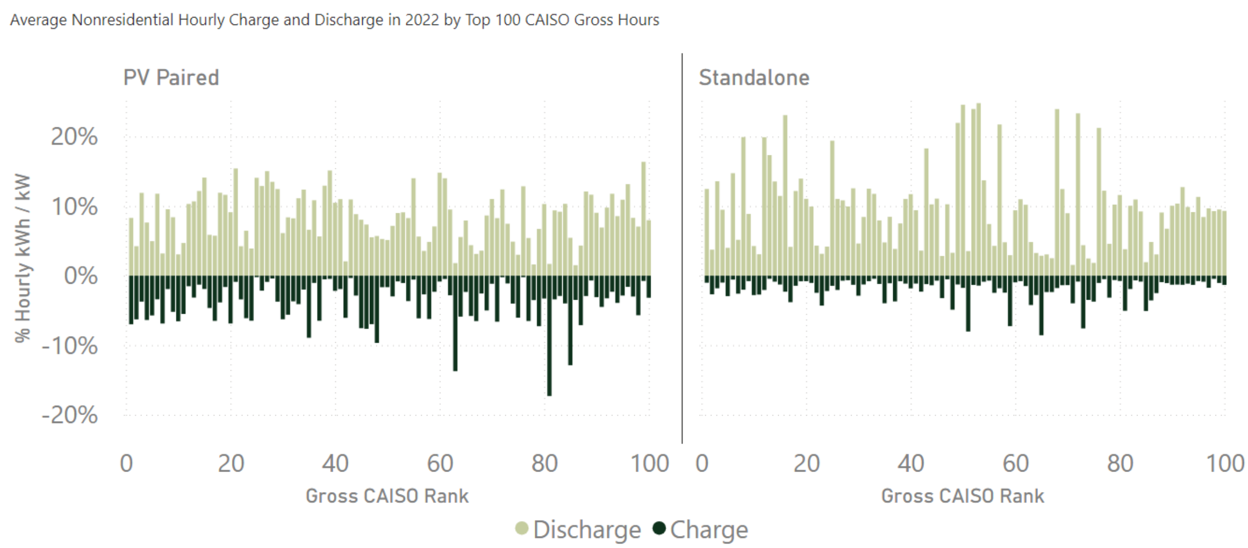


FIGURE 6-96: HOURLY STORAGE KWH PER KW – CAISO TOP NET 100 HOURS FOR NONRESIDENTIAL

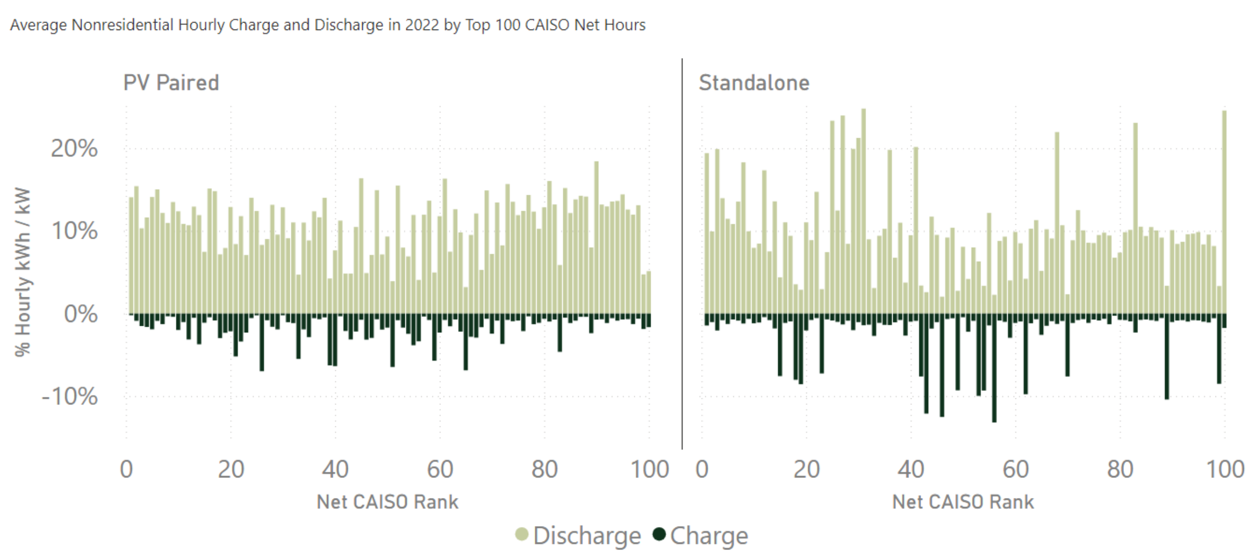


Figure 6-97 and Figure 6-98 provide average hourly charge and discharge during peak hours for the residential sector, across all sampled projects. Standalone residential systems are conducting self-consumption and energy arbitrage, so we expect to observe discharging throughout on-peak net and gross CAISO hours. Standalone system charging occurs almost exclusively after 9 pm and overnight. Some CAISO gross peak hours occur early enough in the day when on-site PV is still generating. Net peaks hours occur later, when both grid-scale and on-site PV generation diminish, and systems begin discharging more regularly to lower or negate on-peak customer load.

FIGURE 6-97: HOURLY STORAGE KWH PER KW – CAISO TOP GROSS 100 HOURS FOR RESIDENTIAL

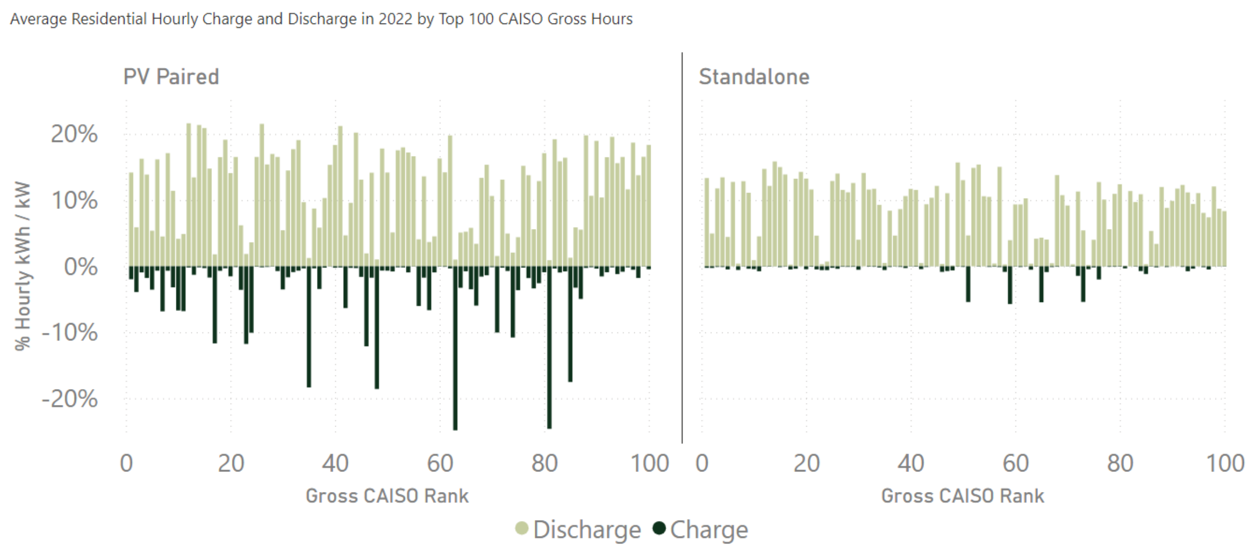
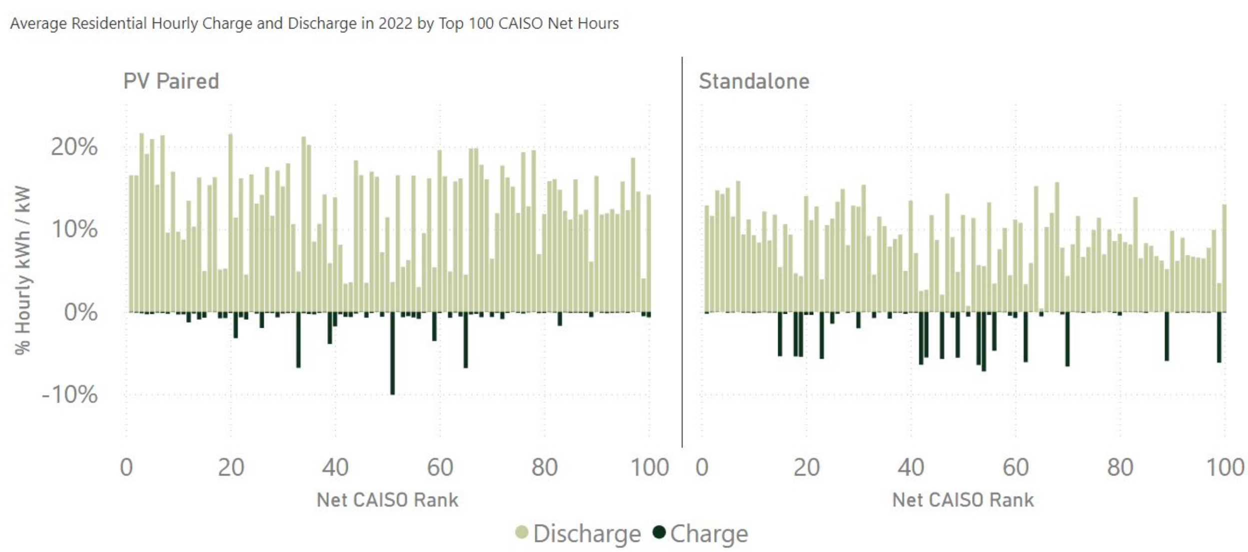


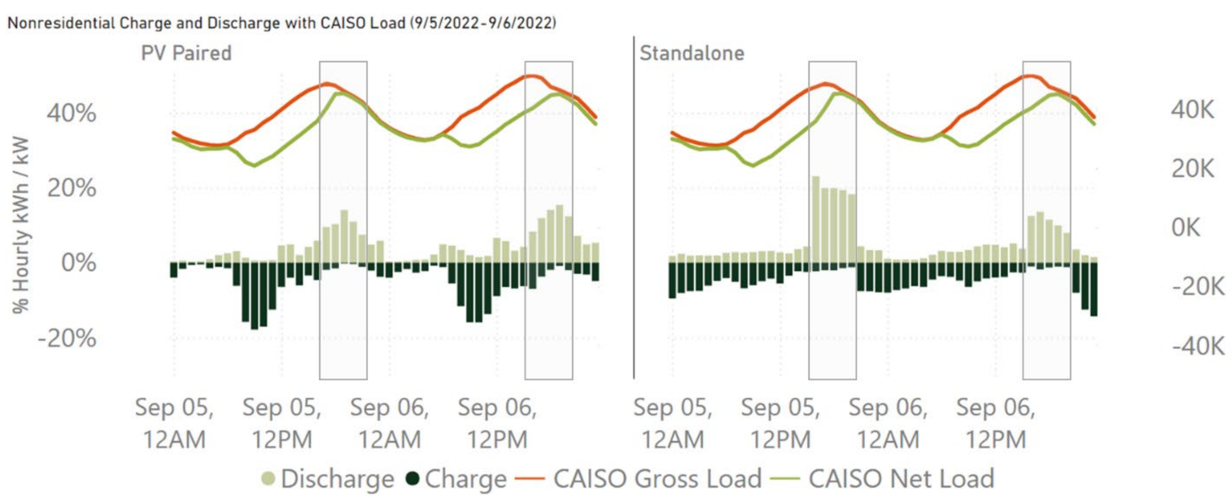
FIGURE 6-98: HOURLY STORAGE KWH PER KW – CAISO TOP NET 100 HOURS FOR RESIDENTIAL



The variability in discharged energy capacity across different time periods and across customer sectors is predicated on the presence of on-site solar generation, underlying load shapes, battery operating modes, and general system utilization. We examine this variability by providing a snapshot of how storage was being dispatched for nonresidential and residential customers during two of the more capacity constrained days in 2022 – September 5th and September 6th. These data are presented below in Figure 6-99 and Figure 6-100. In both figures, the CAISO gross and net loads are provided along with the average hourly charge and discharge of storage for the nonresidential and residential sectors, respectively. The belly of the "duck curve" is evident throughout the morning and early afternoon as grid-scale renewables are generating in conjunction with other supply sources. On September 6th the gross peak occurred during 4 pm local time, followed roughly two hours later by the net peak around 6 pm, with waning grid-scale renewables generation being replaced by imports, traditional fossil fuel burning generators ramp up, and grid-scale front-of-meter (FOM) batteries.

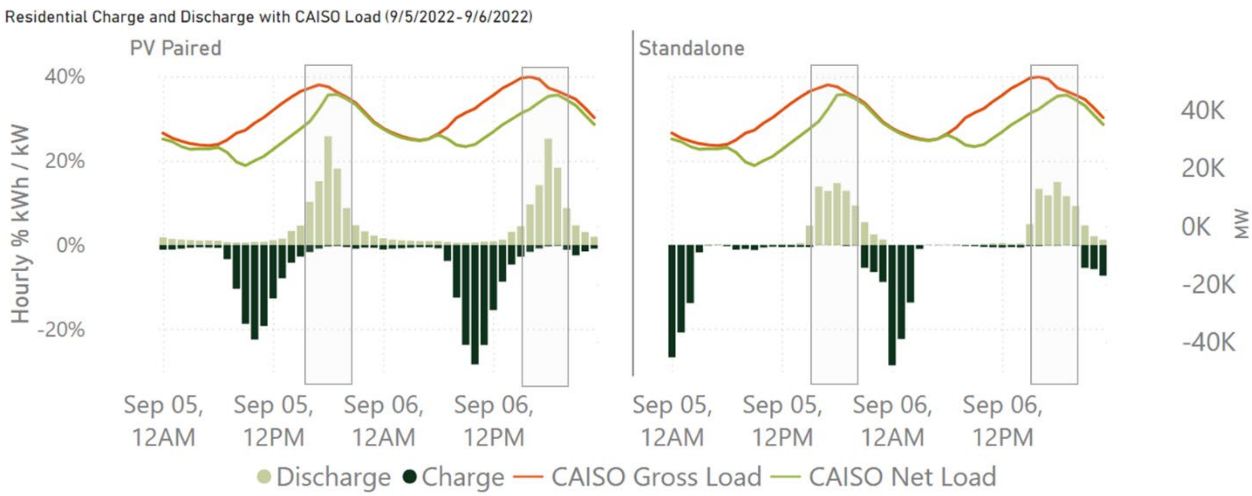
Nonresidential systems, on average, are discharging a greater percentage of capacity during both gross and net peak hours on each day – represented inclusively within the highlighted 4 pm – 9 pm hours – than during any other time throughout the day. Systems paired with PV are absorbing excess on-site solar generation, which aligns well with grid-scale renewables ramping up, and the corresponding belly of the net CAISO load. Standalone systems are discharging more of their capacity than PV paired during the peak and net peak hours (especially on 9/5) and are charging more than paired systems after the on-peak period and into the night when system load begins to drop.

FIGURE 6-99: NONRESIDENTIAL HOURLY CHARGE AND DISCHARGE DURING PEAK CAISO DAYS



Residential systems paired with PV exhibit a somewhat similar charging pattern throughout morning on-site PV generating hours. However, we observe virtually no charging outside of these hours. The greatest magnitude of discharge occurs during on-peak hours (highlighted within the rectangles), with the greatest average discharge magnitude occurring during the 6 pm hour (pacific local time, hour beginning) – which is three hours into the on-peak periods and coincides with peak CAISO net hours. Standalone systems also discharge almost exclusively throughout on-peak periods, and charge almost exclusively, thereafter, beginning at 9 pm local time. Like the nonresidential sector, there is inherent variability in how residential systems are discharging hourly and the magnitude of hourly discharge impacts. However, on average, residential systems are net discharging more of their capacity than nonresidential systems during net peak hours on these days. This is presented in more detail below in Figure 6-100.

FIGURE 6-100: RESIDENTIAL HOURLY CHARGE AND DISCHARGE DURING PEAK CAISO DAYS



The overall pattern of charge and discharge during top CAISO hours – and throughout the summer, in general – follows a similar pattern to what has been observed in previous evaluations. However, the magnitude of impacts during top hours continues to evolve from one evaluation to the next. This is due, in part, to peak CAISO hours differing from year to year as well as the underlying load shapes and use cases of customers in SGIP changing from one year to the next. Two of the more critical recent changes are 1) more focused nonresidential discharging during on-peak hours – particularly with long duration batteries installed via the Equity Resiliency Budget (ERB) category, and 2) residential systems discharging a greater percentage of capacity during the latter half of the on-peak period. Increased price differential between billed on and off-peak, demand response participation like ELRP, and developer fleet dispatch modifications[38] have contributed to more significant benefits realized from the grid perspective.

The magnitude and pattern of nonresidential charge and discharge by budget category is presented below in Figure 6-101 for 9/5-9/6/2022. The 4 pm – 9 pm on-peak is highlighted, along with the hourly CAISO

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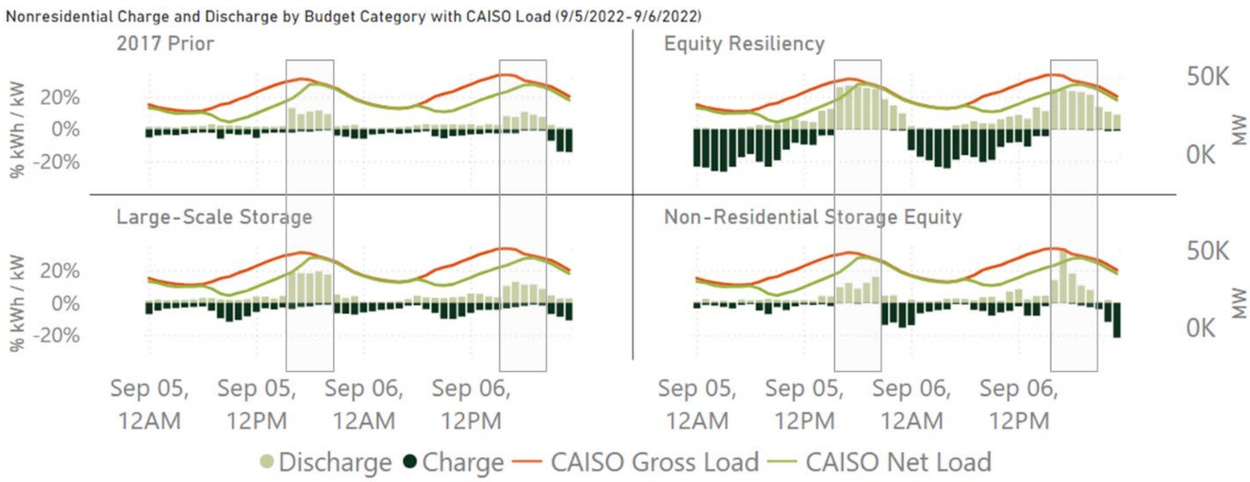
[38] In previous evaluations, Verdant observed the fleet of systems for one developer discharging consistently at 4-5 pm throughout the summer on-peak period. Beginning in the late summer of 2021 they changed the algorithm of discharge and withheld dispatch throughout the first two hours of the on-peak period and began discharging during 6-7 pm. This grid-friendly behavior was observed throughout 2022.

gross and net load during the two days. For all four budget categories, we observe the greatest magnitude of discharge throughout the five-hour peak period. Long duration Equity Resiliency projects are discharging across multiple hours at roughly 20% capacity during on-peak. Timing and duration of charge is predicated on the distribution of PV paired systems represented in each budget category, but overall, charging is left to less critical system hours.

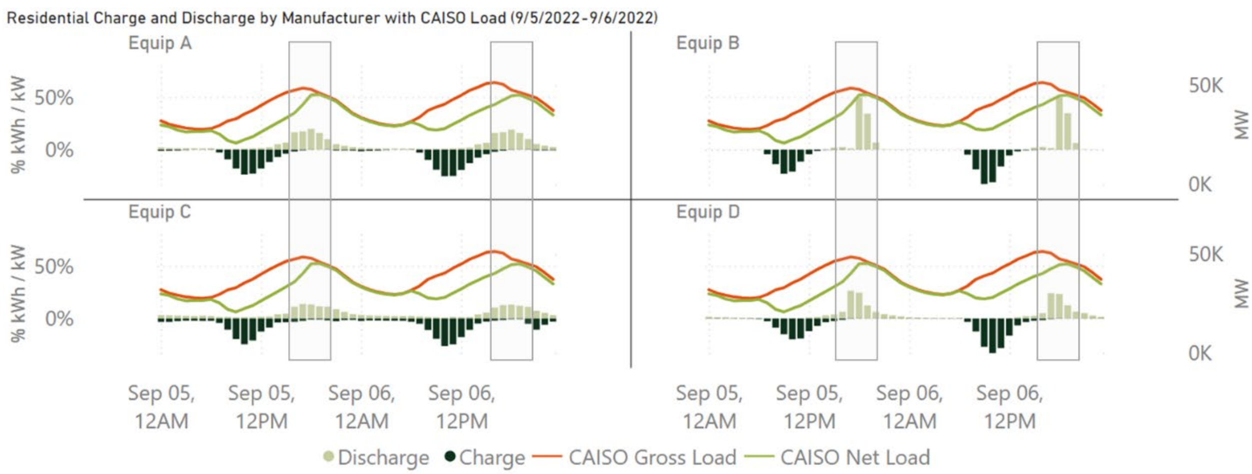
FIGURE 6-101: NONRESIDENTIAL HOURLY CHARGE AND DISCHARGE DURING PEAK DAYS BY BUDGET CATEGORY



As discussed in Section 6.2.1, we observe energy storage systems with different operating modes and overall system capacities. Furthermore, some developers not only meter the battery, but also meter PV production and customer net load. These metering techniques allow the battery to recognize when net load goes positive or negative and provide an opportunity for a customer to conduct self-consumption. These differing modes provide differing arbitrage opportunities and discharge patterns based on how the battery is built and how it interacts with customer load and on-site generation.

Figure 6-102 presents charge and discharge behavior during 9/5/2022 and 9/6/2022 from residential systems differentiated by developer/manufacturer. Moving clockwise from the bottom right, we observe a combination of arbitrage and self-consumption from the first three manufacturer fleets throughout the two days. Discharging coincides with CAISO peak hours and charging coincides with the dip in CAISO net load – when renewable generation makes up a greater share of overall system load. Self-consumption is observed where discharging continues, albeit at much lower magnitudes, after the on-peak ends. The developer represented in the top right quadrant exhibits similar charging behavior but discharges a greater magnitude during the latter hours of the on-peak period and doesn't discharge after – suggesting self-consumption is not an operating mode. Discharge magnitudes represent greater than 50% of kW capacity during the 6 pm hour and continues into the next two hours at diminishing capacity. As mentioned previously, this developer shifted their fleet discharge to the times presented below midway through 2021, whereas prior to that, they had been discharging the greatest magnitude during the 4 pm – 5 pm hours.

FIGURE 6-102: RESIDENTIAL HOURLY CHARGE AND DISCHARGE DURING PEAK DAYS BY MANUFACTURER



Incremental Residential Storage Performance Throughout 2022 Heat Dome Event

During the first full week in September 2022, protracted high temperatures throughout the state created life-threatening conditions for millions and, as evident above, generated well-above normal demands on the CAISO and utility systems. The event itself fueled potential wildfires and stressed the power grid, and Californians experienced flex alerts, and emergency demand response events like ELRP were triggered to help reduce load during some of the more consequential times. The heat dome was then cut short, somewhat ironically, by another uncommon weather event in southern California – an eastern pacific tropical storm.

The previous section highlighted the beneficial SGIP energy storage performance during CAISO peak hours – many of which coincided with the heat dome event. However, the operating modes guiding that beneficial performance during critical hours – self-consumption, arbitrage, arbitrage with export, peak/partial-peak demand charge reduction – were observed outside these constrained hours in 2022. PV paired systems were generally charging during lower grid constrained hours and both paired and standalone systems were discharging in the early afternoon and evening during high utility cost hours and system peaks, particularly in summer months. In other words, SGIP energy storage systems were not performing very differently during capacity constrained hours than they were ordinarily in 2022.

However, we do observe some incremental utilization and performance from systems enrolled in demand response programs like ELRP. During event days, which in 2022 align with those capacity constrained grid hours, systems that were ordinarily arbitraging or self-consuming – but were enrolled in ELRP – were discharging to almost full capacity and to export during event windows. To better understand and quantify any potential incremental performance benefits ascribed to storage during the Heat Dome relative to normal observed dispatch, Verdant compared peak hour system utilization to like day utilization.

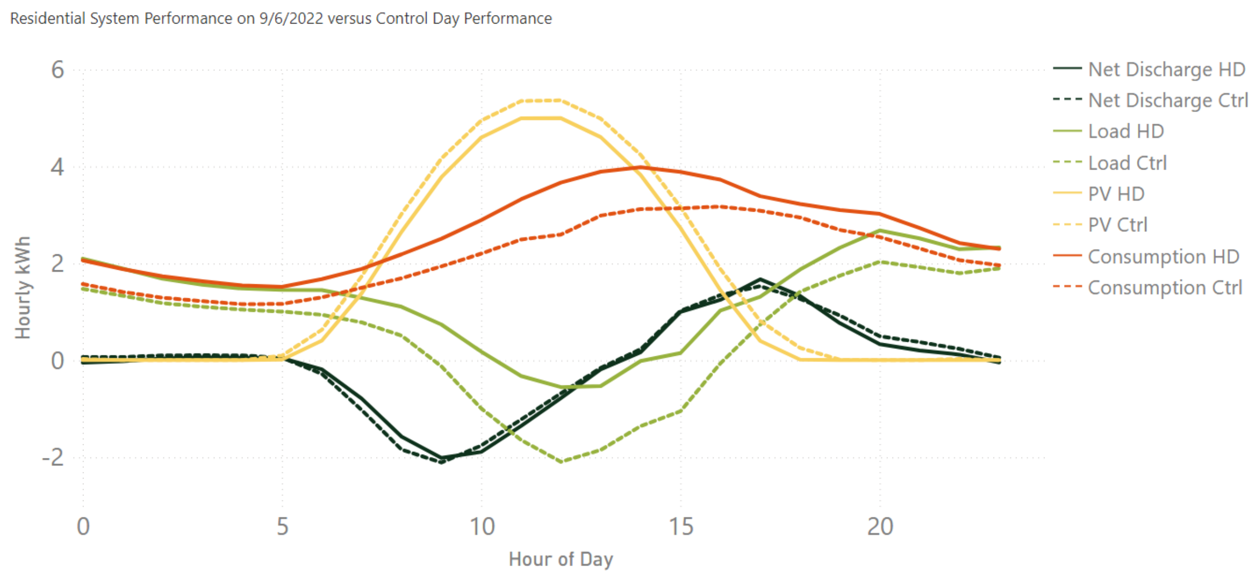
The methods used to classify similar days included mapping weekday weather station information – like minimum/maximum temperature, mean temperature, and temperature during peak hours – to SGIP storage systems by premise-level zip codes. Comparison or control days were then selected using Mahalanobis distance matching, based on a combination of metrics. After reviewing outputs for each set of selected metrics, Verdant chose the smallest Mahalanobis distance using maximum temperature. This method selected the best fitting temperature shape during the peak hours. Occasionally, the selected day was missing system discharge, load, or PV data, and the second closest Mahalanobis distance was selected. If that day contained missing data, the project was removed from the analysis dataset. Data attrition reduced the size of the analysis dataset for the following reasons: 1) no data was available on any heat dome days (~5% of the data); 2) site was decommissioned (~5% of the data); or 3) battery storage, load, or PV generation was zero for all control or all event days (~4% of the data).

It's important to note that this exercise was not intended to replicate a load impact study. Furthermore, the protracted, extreme weather conditions observed during the heat dome truly have no comparison – the anomalous nature and duration of the event create challenges finding representative control days. The research question stems from what potential demand reductions a BTM distributed energy resource like energy storage can reasonably provide for quickly dispatchable grid support (there are 1,200 MWh of installed capacity within the SGIP alone). The question is what percentage of that capacity is already being dispatched for customer TOU arbitrage or self-consumption versus what incremental capacity can be expected from these systems in response to another critical event. The analysis compared 1) energy storage utilization – charge (-) and discharge (+), 2) customer net load, 3) on-site PV generation, and 4) BTM household consumption on heat dome event days compared to control days. Comparisons were made by residential equipment manufacturer, and ELRP participation.

SGIP energy storage systems were not performing that differently during capacity constrained hours than they were ordinarily in 2022.

An example of observed residential performance is presented below in Figure 6-103. Black lines represent hourly storage charge (-) or discharge (+), green lines represent customer load, yellow lines are on-site PV generation, and red lines represent BTM household consumption. Solid lines throughout correspond to load shapes on 9/6/2022 (the top CAISO net hour in 2022 occurred on this day) and dashed lines correspond to control day load shapes. Observations on each load stream are also presented below.

FIGURE 6-103: OBSERVED RESIDENTIAL LOAD SHAPES DURING PEAK DAY VERSUS CONTROL DAY



Customers are exporting less excess PV throughout the event day and are importing more energy on-peak than on control days. Typical received and delivered load shapes for PV plus storage are observed in both cases. However, less export during the event day – without an increase in energy storage charging or a significant reduction in PV generation – suggests more of the PV is going to satisfy BTM consumption.

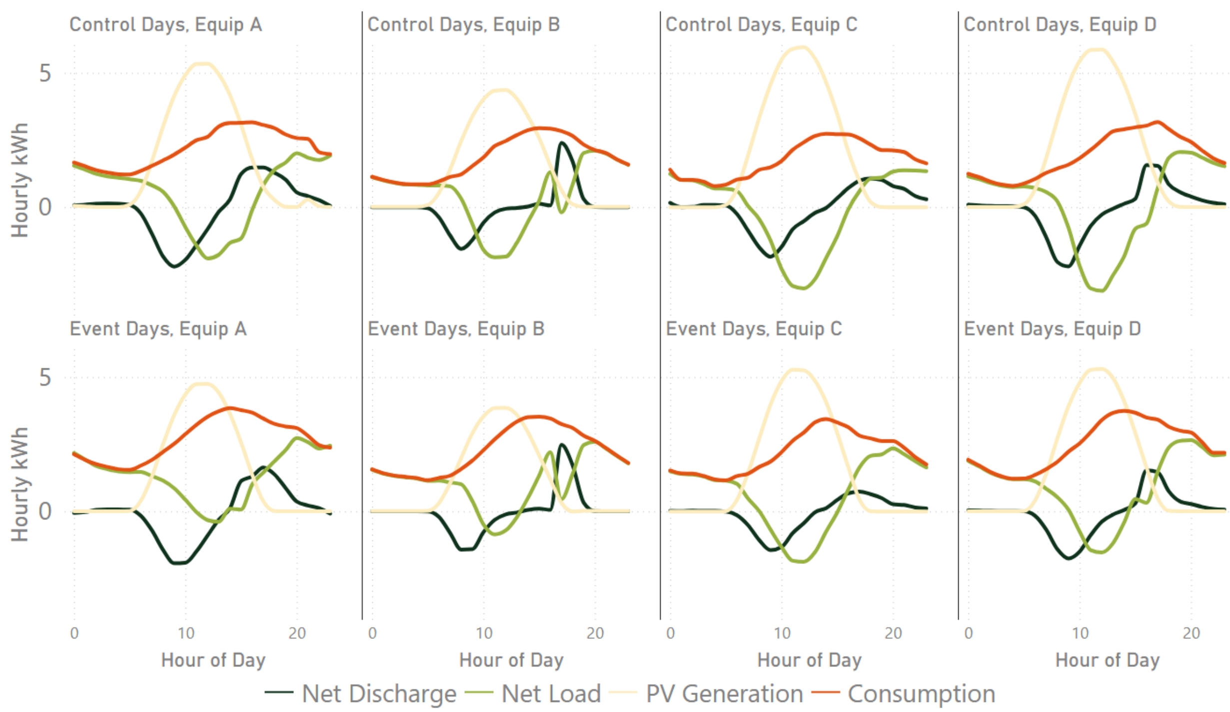
Peak and overall PV generation are slightly higher on controls days compared to the event day. As mentioned previously, identifying matched days to weather events as extreme as the heat dome is difficult. They generally occurred earlier in the summer when daylight hours were a bit longer and solar irradiance was greater.

Household consumption is greater on the event day than comparison days, especially throughout afternoon hours. Extreme and protracted temperatures across the state increased overall cooling demands, including overnight based on higher overnight temperatures.

There is little observable difference in storage system utilization across the days. Increases in household demand on peak days are not translating over to increased storage utilization. Storage system utilization is almost identical, in both charge and discharge, on event and comparison days. Depending on the operating mode and the system manufacturer, storage systems are generally utilizing from 40% to 60% of available kWh capacity throughout the day. Our analysis reveals no discernible increase (or decrease) in utilization, suggesting there was very little incremental value provided by SGIP residential systems overall throughout the heat dome event.

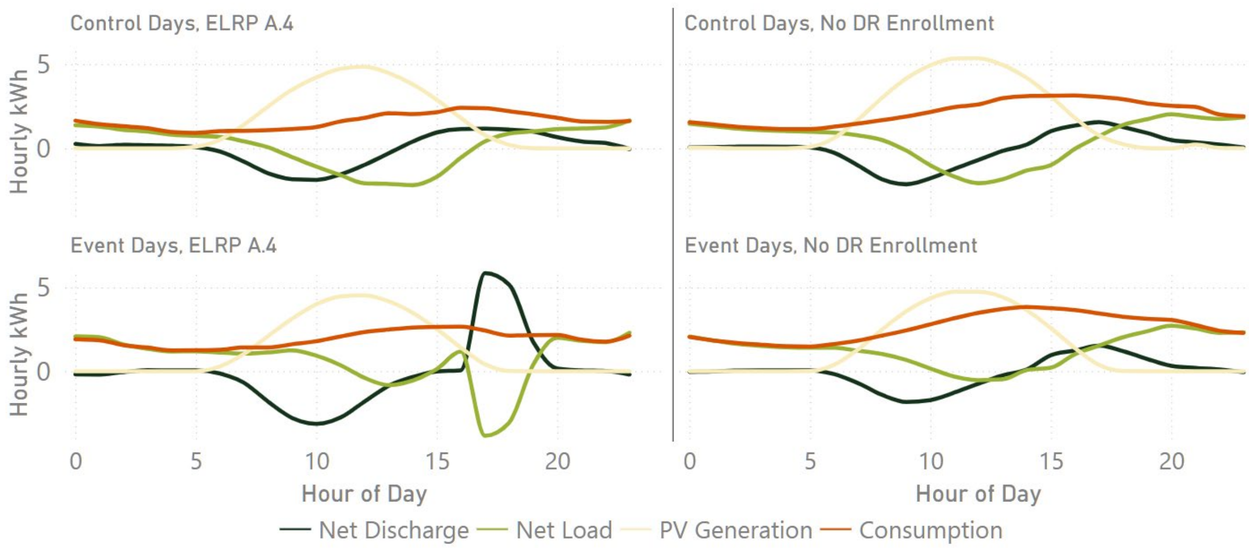
The evaluation team also reviewed the storage performance and load shapes by the four primary system equipment manufacturers during the Heat Dome event and compared utilization and household consumption to control days. Figure 6-104 presents the average load shapes by manufacturer across the four Heat Dome days (bottom four exhibits) and the corresponding control days (top four exhibits). As presented in the previous section, differing operating modes provide differing arbitrage opportunities and discharge patterns based on how the battery is built and how it interacts with customer load and on-site generation. While we again observe differences in storage dispatch across manufacturers – particularly with the Equip B fleet discharging regularly to export – storage utilization during event days and control days are almost identical for each manufacturer.

FIGURE 6-104: AVERAGE RESIDENTIAL LOAD SHAPES ACROSS PEAK AND CONTROL DAYS BY MANUFACTURER



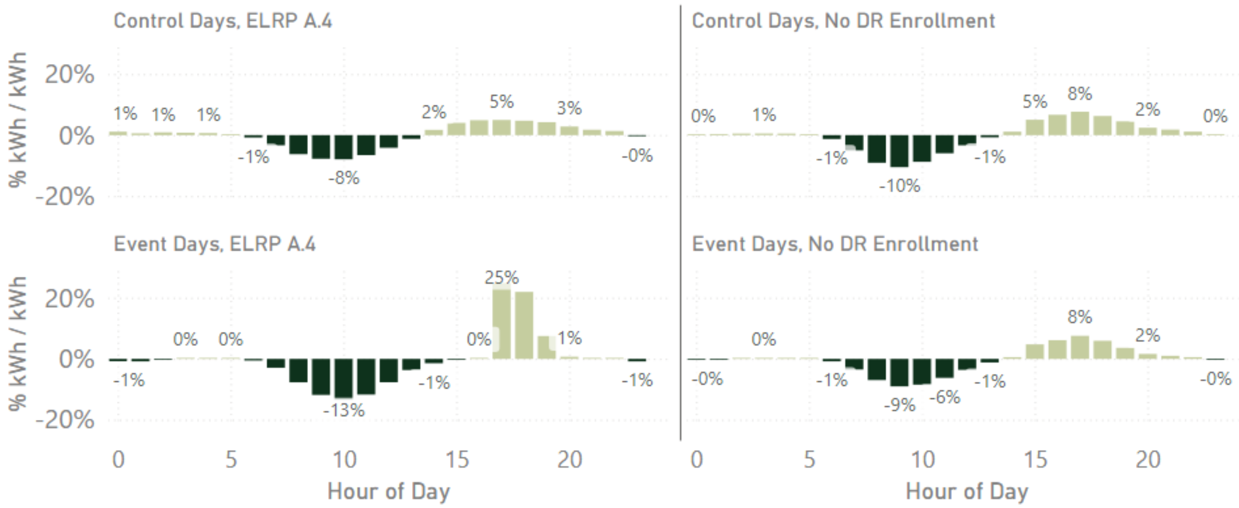
Storage systems are generally following a price signal built into a customer billed on- and off-peak rate schedule, so behavioral changes from event days to control days would be either wholly coincidental or predicated on additional signals to customers – flex alert notifications and/or demand response participation where, in the case of ELRP, load reductions can be compensated at up to $2.00 per kWh. ELRP participation is where we observe differences in storage dispatch between event and control days. The roughly 6 kWh magnitude of average discharge during each of the first two hours of the ELRP events on 9/5-9/8 is evident in the bottom left of Figure 6-105. Not only were ELRP participants discharging a greater magnitude of system capacity during events, but discharge also extended beyond customer load requirements. Excess discharge was being exported to the grid – a behavior from this cohort of systems that wasn't observed ordinarily throughout the year. We also observe increased charging throughout event days because greater discharge utilization resulted in lower end-of-day state-of-charge (SOC). Again, no observed changes in utilization were observed with systems on the right not enrolled in ELRP.

FIGURE 6-105: AVERAGE RESIDENTIAL LOAD SHAPES ACROSS PEAK AND CONTROL DAYS BY ELRP ENROLLMENT



Average net discharge as a percentage of system kWh capacity is detailed below for the same conditions presented above. Charging is represented as negative dark bars and discharge is positive and light green. Systems enrolled and participating in A.4 ELRP exhibited a fivefold increase in discharge throughout the first two hours of the 4pm to 9pm event window relative to control day utilization (25% versus 5% of capacity hourly). The almost identical utilization in the top and bottom right reiterates that there are no discernible differences between observed charge and discharge behavior throughout peak grid hours and normal operations for non-ELRP systems.

FIGURE 6-106: AVERAGE RESIDENTIAL NET DISCHARGE ACROSS PEAK AND CONTROL DAYS BY ELRP ENROLLMENT



6.3.2 Generation

Unlike energy storage, generation technologies are not typically used for load shifting or TOU arbitrage but are mostly used to satisfy a customer's base load. Therefore, while they can provide peak hour benefits, these benefits are not typically greater than will be seen the rest of the year. Generation coincident with the gross and net CAISO annual peak hours during 2022 (i.e., the impact in terms of reducing the gross or net load peak) is shown by PA in Table 6-3. SoCalGas projects contributed the largest portions of the gross CAISO peak hour generation, making up between 40 and 50% of the total generation during both the CAISO gross and net peak hours of 2022.

TABLE 6-3: ANNUAL CAISO GROSS AND NET PEAK DEMAND IMPACT BY ELECTRIC UTILITY

CAISO	PA	Peak Hour Generation [MW]	Percent of Total
Gross	CSE	17.13	9.5%
	PG&E	48.56	26.8%
	SCE	24.70	13.6%
	SoCalGas	90.73	50.1%
	Total	**181.12**	**100%**
Net	CSE	16.35	9.0%
	PG&E	51.06	28.0%
	SCE	24.17	13.3%
	SoCalGas	90.82	49.8%
	Total	**182.41**	**100%**

Figure 6-107 below highlights the breakout of the CAISO gross peak hour generation by incentive design. Projects with ongoing PBI requirements made up the largest CAISO peak hour generation, generating on average 0.7 kW per rebated kW during 2022. No projects receiving only capacity-based incentives were observed during the 2022 CAISO peak hour.

FIGURE 6-107: 2022 OBSERVED CAISO GROSS PEAK DEMAND IMPACT PER REBATED CAPACITY [KW] BY INCENTIVE DESIGN

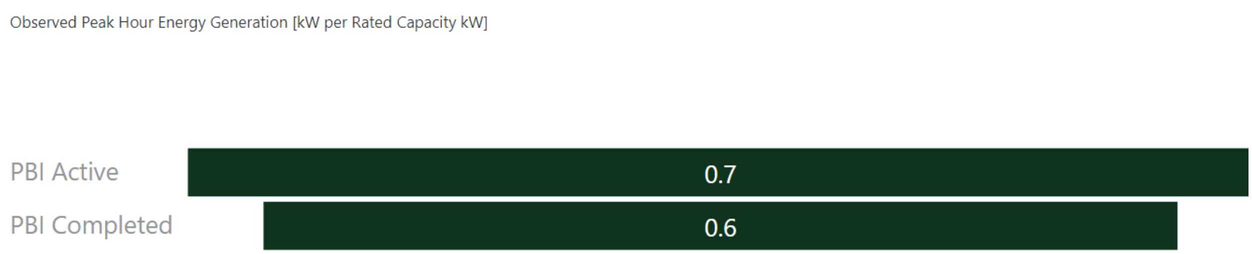


Figure 6-108 and Figure 6-109 shows the CAISO gross peak demand impact per rebated capacity, by technology type total, as well as broken out by PA. Across all PAs, gas turbines generated the highest peak demand impact per rebated kW during 2022 during the statewide gross peak, followed by CHP fuel cells and pressure reduction turbines. in 2022, statewide. When comparing by PA, pressure reduction turbines, fuel cells, and gas turbines typically saw the highest peak demand impact per rebated kW.

FIGURE 6-108: 2022 OBSERVED CAISO GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE (TOTAL)

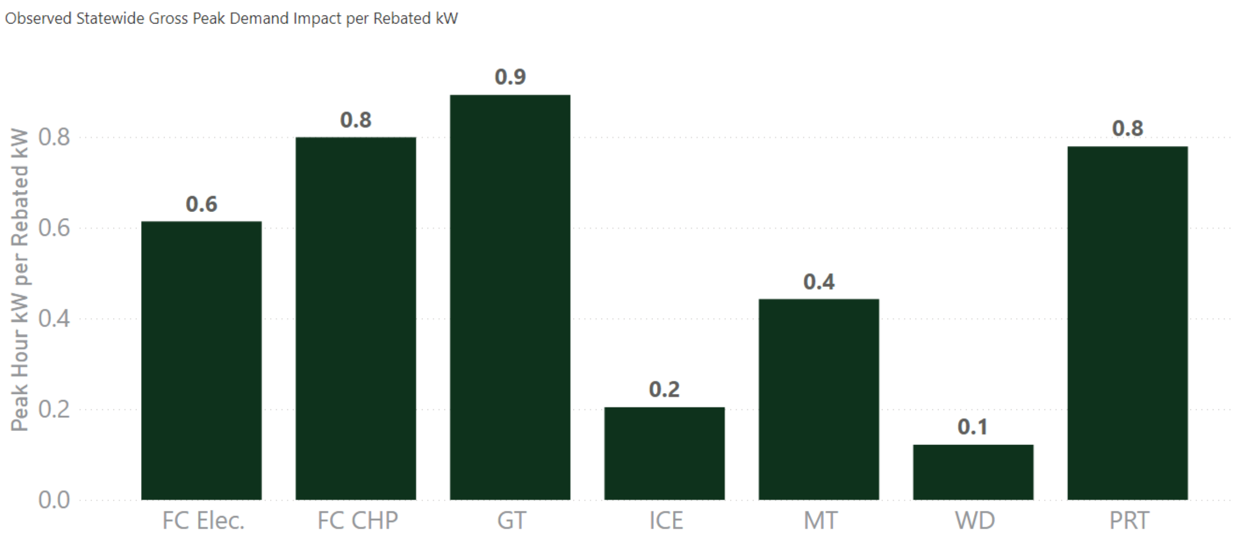
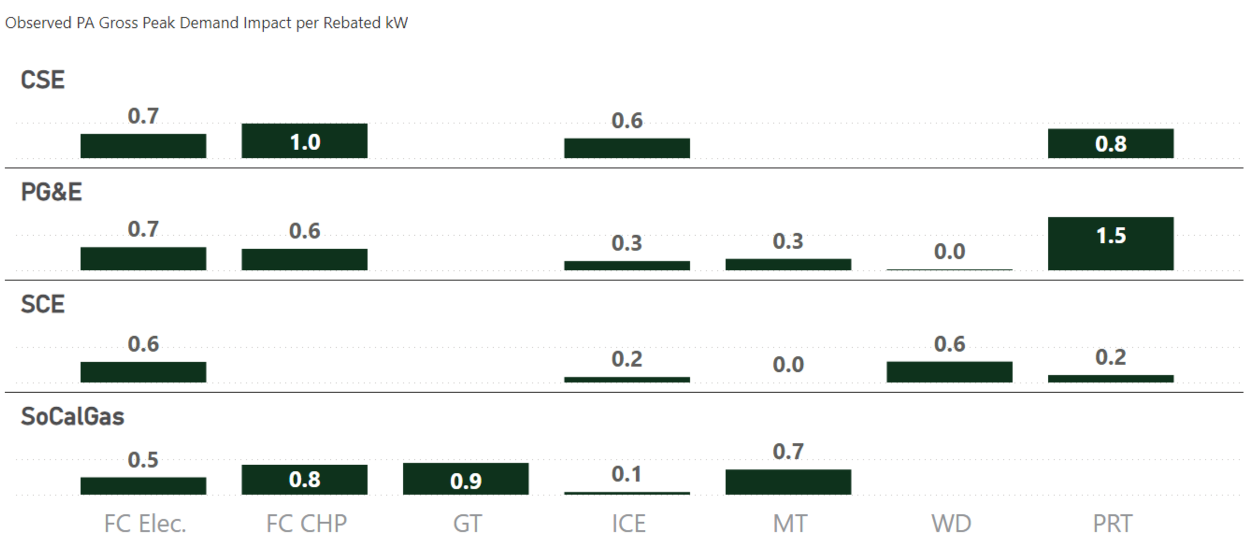


FIGURE 6-109: 2022 OBSERVED CAISO GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE AND PA



Gross Peak IOU impacts were also analyzed, as displayed in Figure 6-110. These peak hour impacts from SGIP systems are assigned to the IOU providing the electrical service, which is not necessarily the same as the PA. SoCalGas projects may be electrically interconnected to a municipal utility rather than an IOU.

The 2022 PG&E gross peak hour generation occurred on September 6th, between 4-5 PM local time. During this hour, observed projects electrically interconnected to PG&E's system generated 0.4 kW per rebated kW. SCE's 2022 gross peak hour was on September 7th between 3 and 4 PM, where coincident generation from observed projects was 0.6 MW per rebated kW. Observed projects interconnected to SDG&E's electrical system reached 0.7 MW per rebated kW during the 2022 gross peak hour on September 7th between the hours of 4 and 5 PM.[39] Similar to the CAISO findings, on a per rebated kW basis, observed CAISO peak hour generation per kW was generally led by pressure reduction turbines, fuel cells, and gas turbines.

FIGURE 6-110: ANNUAL IOU GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE AND ELECTRIC UTILITY

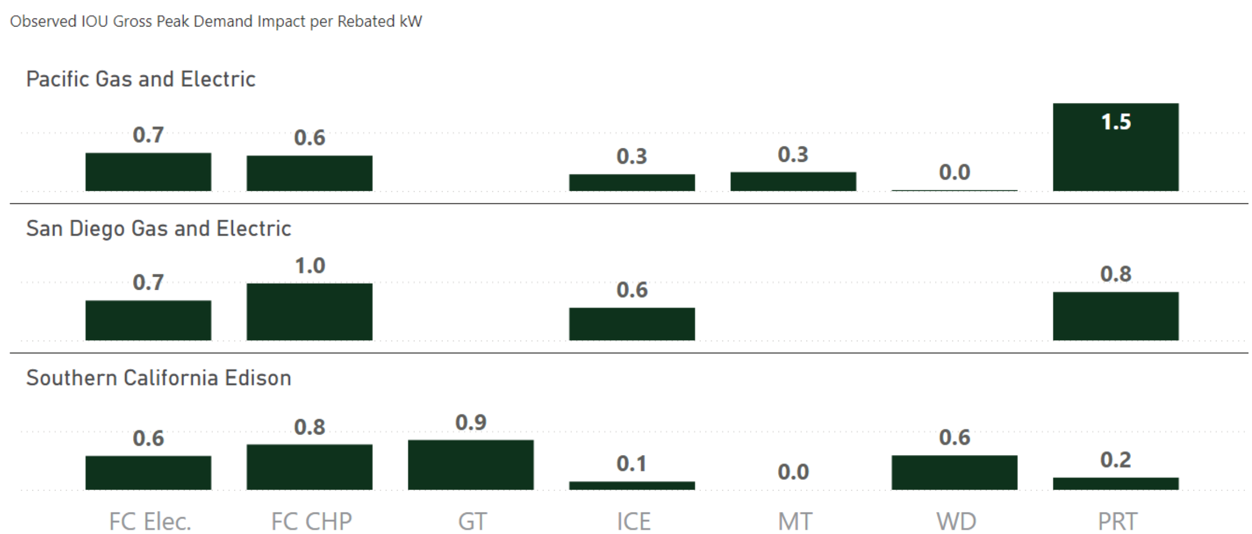
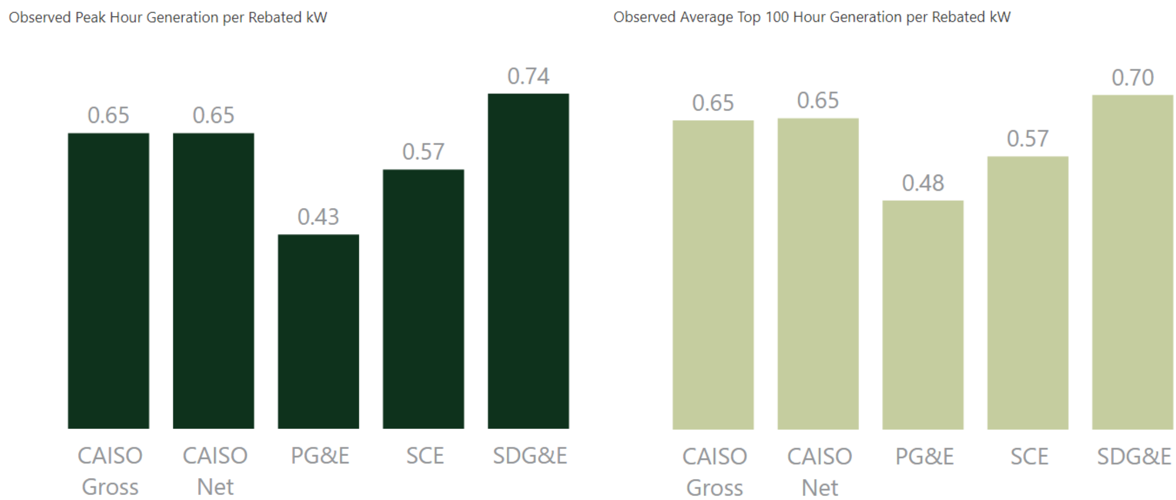


Figure 6-111 shows observed project generation per rebated kW coincident with the three IOU and CAISO gross and net peak hours, alongside average project generation per rebated kW coincident with the top 100 peak hour. On a per rebated kW basis, peak hour generation and top 100 hour average generation were very close in all cases.

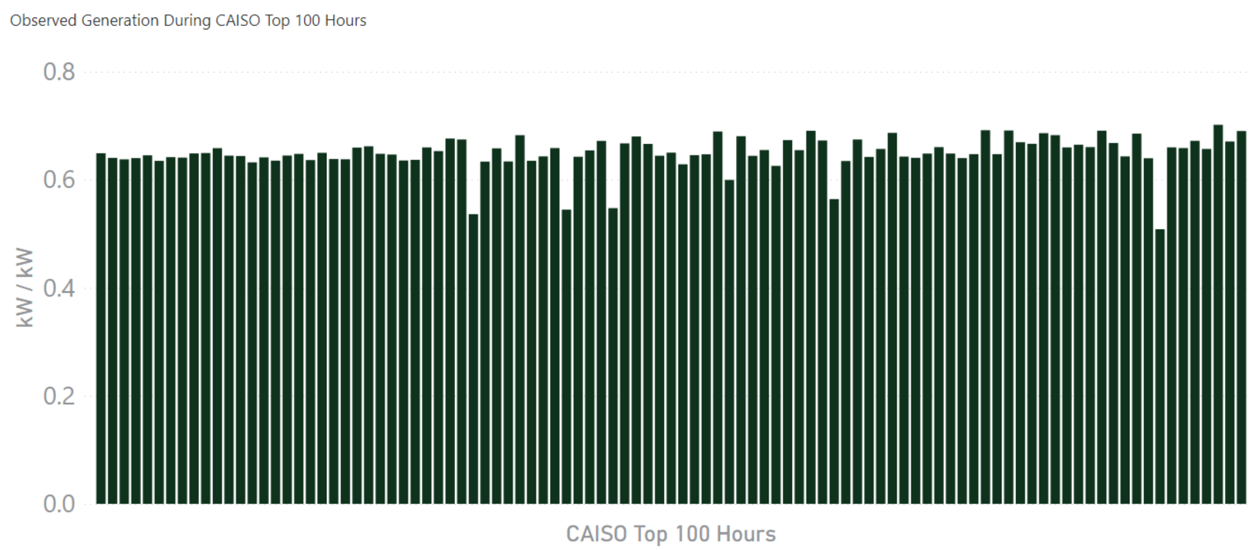
[39] The defined peak hours are all in local time.

FIGURE 6-111: OBSERVED PEAK HOUR GENERATION COMPARED TO AVERAGE TOP 100 HOUR GENERATION [PER KW]



As discussed in Section 6.1.2 generation systems typically provide a baseload, rather than providing peak hour benefits. Figure 6-112 below highlights the observed generation per rebated kW over the CAISO top 100 hours, showing that the generation per rebated kW generally stays steady across the top 100 hours.

FIGURE 6-112: OBSERVED CAISO TOP 100 HOUR GENERATION PER REBATED KW



6.4 ENVIRONMENTAL IMPACTS

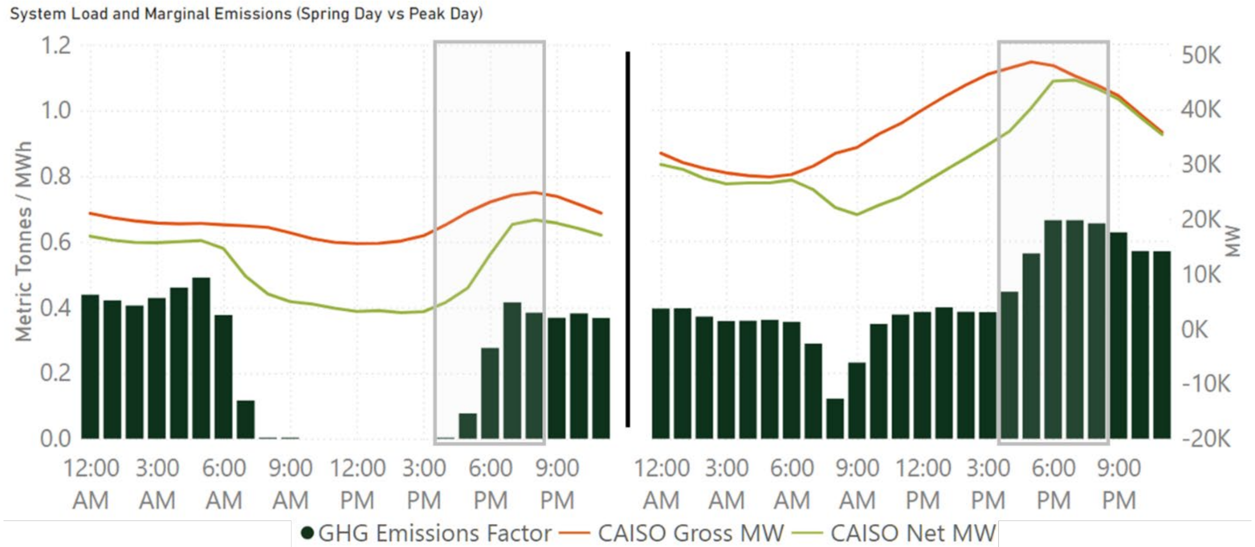
The environmental impact considered in this analysis is change in emissions of the GHG CO_2, as CO_2 is the GHG most affected by the operation of SGIP systems.[40] Environmental impacts are calculated as the difference between the CO_2 emissions associated with SGIP system operations and those associated with counterfactual baseline system operations. In the case of generation systems, numerous possible baseline conditions are possible depending on the type of fuel being utilized by the SGIP system. When the baseline entails venting of methane directly to the atmosphere the GHG impact is expressed in terms of equivalent CO_2 (CO_2eq). Details of GHG impacts calculations for generation systems are provided as Appendix D. Generation systems and energy storage systems both change the timing and magnitude of CO_2 emissions of electric utilities. This aspect of the environmental impacts analysis is described below.

The relationship between electric grid load and marginal CO_2 emissions is depicted graphically in Figure 6-113. Two days in 2022 are presented; 1) 5/1/2022 – a sunny, Sunday in May on the left, 2) 9/6/2022 – on the right, where CAISO Net Load reached its 2022 peak during the 7pm hour local time. The red and green lines represent hourly CAISO Gross and Net load, respectively, and the dark green bars represent average marginal emissions during that hour. Also highlighted are the 4pm-9pm hours for each day.

System load and corresponding marginal emissions on the left are typical of a spring day. For many hours during the day where marginal emissions are zero, ample sunshine, long daylight hours, and low demand for energy-intensive end uses like A/C allow grid-scale renewable solar generation to provide all but some base load to satisfy system demand – and even after exporting to other states, some of the grid-scale renewables must actually be curtailed to keep the grid stable, resulting in zero or even negative prices in the CAISO. Marginal emissions are zero when renewables are being curtailed, because more load will be met by reducing curtailment rather than by increasing GHG-producing generation. During the 4pm and 5pm hours, renewable generation continues to decrease from its mid-day maximum and is displaced by more carbon-intensive generators. The three-hour average CAISO net load ramp during those early on-peak hours was roughly 5,000 MW/hr, represented by the steep green line and associated increase in marginal emissions.

[40] The real-time marginal GHG emissions signal developed by WattTime represents the compliance signal for this evaluation and the SGIP, in general. These data are publicly available here: https://sgipsignal.com/.

FIGURE 6-113: CAISO LOAD AND MARGINAL EMISSIONS ON SPRING DAY VERSUS PEAK DAY



System load on the peak day (right pane of Figure 6-113) is much greater and marginal emissions don't hit zero at any point throughout the day (although we observe a drop between 8am – 10am when grid-scale renewables begin to ramp, and underlying system demand is still low). At the net peak (6pm-9pm) emissions remain constant where the upper bound of power plant heat rate is reached – signifying the most carbon-intensive generator is operating at the margin throughout those hours. A perfectly designed energy storage system optimized to reduce GHG emissions would charge only during the lowest marginal emissions periods and discharge during (net) peak hours only.

Generation systems, on the other hand, generally provide a baseload to the facility, and don't have significant variation hour to hour or season to season and are therefore not optimized to maximum GHG emissions reductions during peak hours. Renewably fueled systems with vented baselines saw the highest GHG emissions reductions, but non-renewable fueled systems with high heat recovery rates also reduced GHG emissions.

The marginal grid GHG emissions values used to calculate environmental impacts were prepared by WattTime. The data sources and analytic methodology used by WattTime are consistent with the Avoided Cost Calculator and are approved by the CPUC. Assumptions in the Avoided Cost Calculator are updated periodically. Updated assumptions in the 2020 ACC and the 2021 ACC provided motivation for an update to the SGIP GHG Signal calculations. That update resulted in WattTime releasing a new version of the SGIP GHG Signal starting February 1, 2022: Version 2.[41]

Updates to the ACC's assumptions for natural gas transportation costs and variable power plant operating and maintenance costs resulted in Version 2 marginal GHG emissions values being higher than Version 1. While GHG impacts are influenced by many factors, this change from Version 1 to Version 2 GHG Signal values is particularly important where accounting for differences between 2020 impacts evaluation results and 2021-2022 impacts evaluation results is concerned. The size of the change is summarized in Table 6-4, which presents annual average marginal GHG emissions rates for 2020 (Version 1) and 2021-2022 (Version 2).

TABLE 6-4: AVERAGE SGIP GHG SIGNAL TREND (KG CO2 PER KWH, 2020-2022)

IOU	Version 1 2020	Version 2 2021	Version 2 2022
PG&E	0.245	0.371	0.369
SCE	0.235	0.319	0.342
SDG&E	0.245	0.329	0.347

6.4.1 Energy Storage

Hourly GHG impacts were calculated for each SGIP system as the difference between the grid power plant emissions for observed system operations and the emissions for the baseline condition or the counterfactual. Baseline emissions are those that would have occurred in the absence of the storage system. Facility and household loads are identical for baseline and SGIP conditions. What varies is the timing and quantity of grid power plant electricity required to maintain balance between loads and electrical supply in response to storage charging and discharging.

Hourly storage performance is equal to the charge or discharge that occurred during that interval. The energy impact during that interval is then multiplied by the marginal emissions rate for that interval (kilograms CO_2 / kWh) to arrive at an hourly emissions impact. Emissions generally increase during storage charge and decrease during storage discharge. A system's annual GHG impact is the sum of the total emissions.

Energy storage technologies are not perfectly efficient. Consequently, the amount of energy they discharge over any given period is always less than the amount of energy required to charge the system.

41 Presentation: 'SGIP GHG Signal Update', WattTime. Self-Generation Incentive Program Fourth Quarterly Workshop, December 13, 2021.

Roundtrip efficiency (RTE) losses from AC/DC power conversion and parasitic loads – particularly with underutilized systems – will always result in increased energy consumption at a customer's home or facility relative to the baseline condition without storage. For energy storage systems to reduce emissions, the emissions *avoided* during storage discharge must be greater than the emission increases during storage charging. In other words, SGIP storage systems must charge during "cleaner" grid hours and discharge during "dirtier" grid hours to achieve GHG reductions. Grid-level renewable generation during morning and early afternoon hours helps satisfy system-level demand throughout those hours. During periods when more renewables are on the grid, marginal GHG emissions tend to reduce as well. As renewable generation wanes in the late afternoon and demand ramps are satisfied on the margin with more imports and natural gas peak generators, marginal emissions tend to increase.

Nonresidential Storage

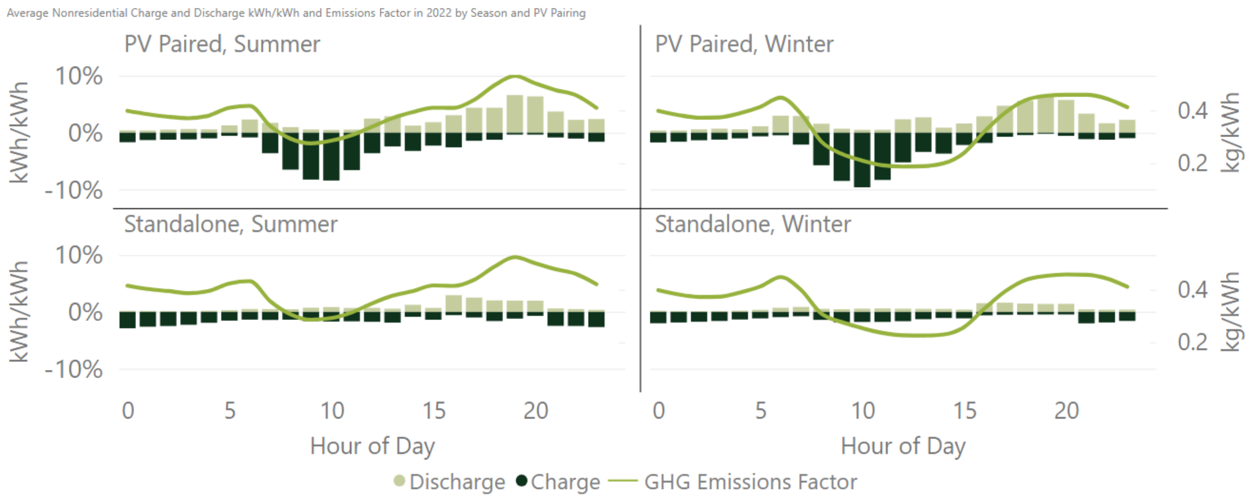
Figure 6-114 presents the range in GHG emission reductions (-) or increases (+) for the sample of nonresidential projects analyzed as part of the 2022 impact evaluation. These boxplots are disaggregated by the year in which an SGIP energy storage project received their incentive payment, along with a flag representing on-site PV pairing or not. We observe an overall increase in system efficiency and utilization from systems installed more recently, and this behavior helps contribute to many more realized GHG emission benefits. The boxplots capture the project variance with some whiskers extending well below or above the average impact for each category. On average, systems paired with PV – independent of payment year – reduced emissions in 2022, with average reductions (-) ranging from 3.5 kg/kWh for systems paid in 2017 and prior to as high as 21.7 kg/kWh for systems paid in 2021. Standalone systems increased emissions in 2022, except for systems paid in 2021 and 2022. Emission increases ranged as high as almost 12 kg/kWh to a low of 5 kg/kWh for systems with 2020 upfront payments. Earlier generation nonresidential storage systems – those incentivized from 2014 to 2017 – exhibit higher average emissions than systems receiving incentives more recently.

FIGURE 6-114: GHG EMISSIONS (KG/KWH) FOR NONRESIDENTIAL SYSTEMS BY PAYMENT YEAR AND PV PAIRING

Recent reductions in GHG emissions in the nonresidential sector are largely attributable to PV paired storage performance and more recent installations of longer duration batteries conducting arbitrage at the expense of non-coincident peak demand reductions (and subsequent charging "snapback" associated with demand shaving). The former point has been highlighted previously and is reiterated below in Figure 6-115. Here we present four exhibits of average energy storage charge (-) and discharge (+) kWh/kWh capacity along with the average marginal emissions shapes by – moving clockwise from top left – 1) PV paired systems operating in summer months of 2022, 2) PV paired systems operating in winter, 3) standalone systems operating in winter months of 2022, and 4) standalone systems operating in summer. The marginal emissions curve (with units displayed on the secondary vertical axis) conveys the hour-by-hour variability in emissions magnitudes. Both summer and winter months exhibit a morning ramp when system demand begins, but prior to grid-scale renewable generation. The subsequent dip in emissions thereafter is caused by renewable generation ramping. In winter months, the dip (or belly) is more pronounced and persists longer throughout the day. Summer months are laden with much higher cooling loads later in the day – represented by the peak from 7 pm to 9 pm.

More importantly than highlighting the marginal emissions in isolation, is the corresponding energy storage performance during those hours. Dark bars represent charging, and we observe much greater charging from on-site solar for paired systems, which is also coincident to lower marginal emissions periods. Discharging (light green bars) is observed throughout on-peak hours and coincident to high marginal emissions. Standalone systems also discharge throughout the peak, albeit at lower magnitudes on average than PV paired systems – and are "net" charging in all other hours.

FIGURE 6-115: NONRESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY SEASON AND PV PAIRING

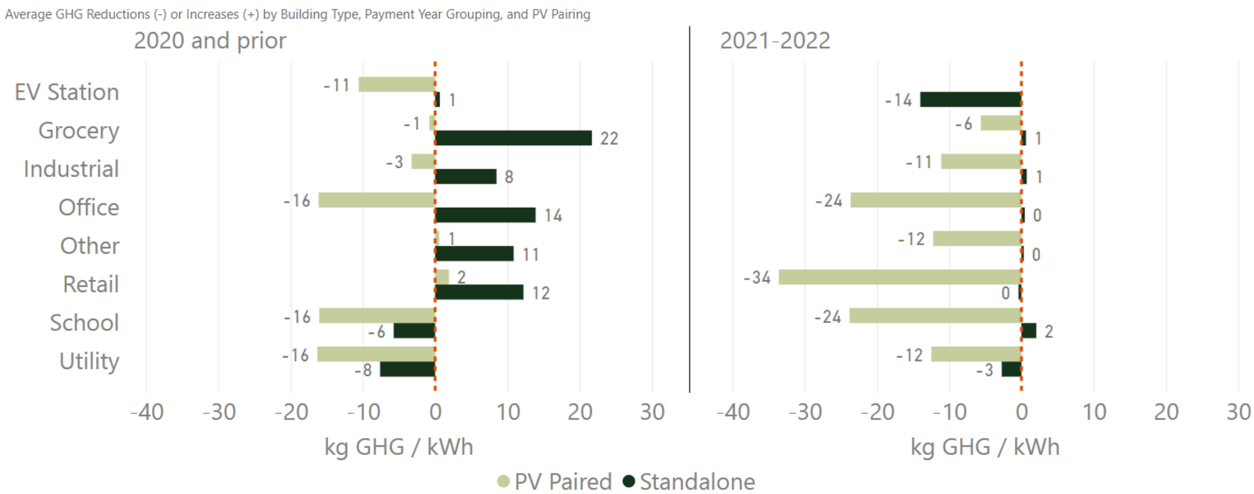


The above figure is an average across the fleet of nonresidential systems and belies some of the more nuanced performance by budget category, facility type, and battery size. The correlation between well-utilized, PV paired systems and emissions reductions is further detailed below in Figure 6-116. This figure also details how standalone nonresidential systems – especially those receiving upfront payments in 2021 or 2022 – were reducing emissions in 2022 as well.

Overall, improved performance from legacy systems and favorable behavior from more recent installations have significantly improved nonresidential GHG performance in 2021 and 2022, relative to past evaluation years.

Verdant has combined systems paid in 2020 and prior (left) and compared those against systems paid in 2021 or 2022 (right). Comparisons for each period are made by facility type and presence of on-site PV. Bars moving left from the vertical red dashed reference line of zero represent average reductions in emissions (kg /kWh) for each of the facility types on the left. Bars moving right from the reference line signal increases in emissions. Standalone systems are presented in dark green, and PV paired systems are presented in light green. For many of the reasons discussed above, PV paired systems are reducing emissions – independent of facility type – with magnitudes of reductions more prominent for systems paid in 2021 or 2022. The more surprising detail is the standalone emissions reductions – particularly for EV stations and Utility classifications. Systems installed at dedicated EV charging stations are themselves charging exclusively during morning off-peak hours and discharging on-peak, potentially due to high peak to off-peak differentials in EV rates, or driver behavior favoring EV charging (and thus SGIP battery discharging) late in the day. Utility classification represents mostly critical facilities incentivized through the ERB. The most common installations are medium duration (4-6 hour) batteries installed at wastewater treatment plants servicing a low-income community. We've already discussed how these systems regularly discharge throughout peak hours and charge overnight (often creating a new facility peak as a result). Overall, improved performance from legacy systems and favorable behavior from more recent installations have significantly improved nonresidential GHG performance in 2021 and 2022, relative to past evaluation years.

FIGURE 6-116: NONRESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY PAYMENT YEAR AND PV PAIRING



As discussed in Section 3.1, provisions in D. 19-08-001 regarding greenhouse gas (GHG) emissions provide developers and host customers with an opportunity to design and dispatch storage technologies in a manner that is beneficial from both a customer and a GHG emissions perspective. The decision was both forward looking and retrospective by introducing program GHG compliance pathways and operational requirements for different vintages of SGIP rebated storage systems. The key provisions set forth in the decision include:

- Defines how different operational and compliance pathways influence different project types
  - New projects submitted a Reservation Request Form (RRF) on or after 4/1/2020
  - Legacy projects completed an RRF any time prior to that date
- Different compliance pathways were developed for new versus legacy projects and for residential versus nonresidential systems
- Defined what constitutes a developer fleet

New nonresidential projects, those submitting an RRF on or after 4/1/2020 are required to reduce emissions by a minimum of 5 kg/kWh each year. Legacy nonresidential systems within their ten-year permanency must select one of three GHG compliance pathways; 1) projects continue to comply with RTE operational requirements in place when the project was approved, 2) projects can enroll in a demand response (DR) program or enroll in an SGIP approved storage rate or 3) projects are required to emit zero kg/kWh or less at the developer fleet level, in place of the RTE requirement.

Figure 6-117 presents the range in annual emissions for nonresidential systems by legacy status. As previously presented, we observe more advantageous storage performance – from a grid and emissions perspective – from more recent program participants as arbitrage, timelier on-peak discharge, and on-site solar charging have increased in frequency in the past couple of years. The dark green scatter plots represent new projects, and the much larger contingent of legacy systems are presented in green. Bubble sizes correspond to project size in kWh and, along with the zero-emissions reference line in dashed red, the average impact is highlighted in dashed dark green. The average across the fleet is slightly negative, representing roughly a 3.1 kg/kWh reduction in GHG emissions in 2022 across project legacy status.

FIGURE 6-117: NONRESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY LEGACY STATUS

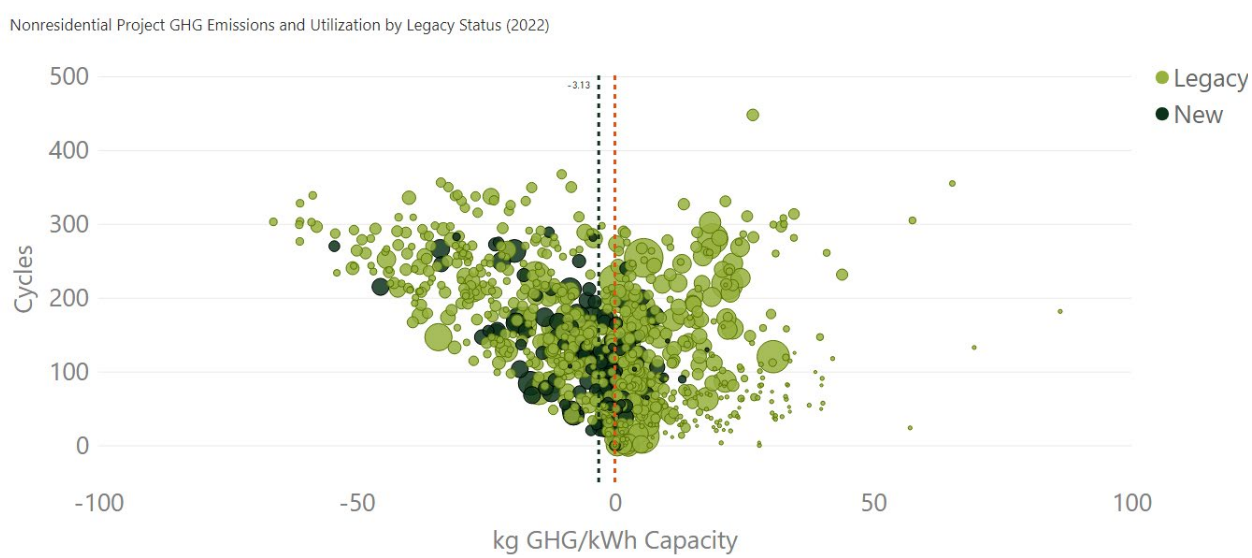
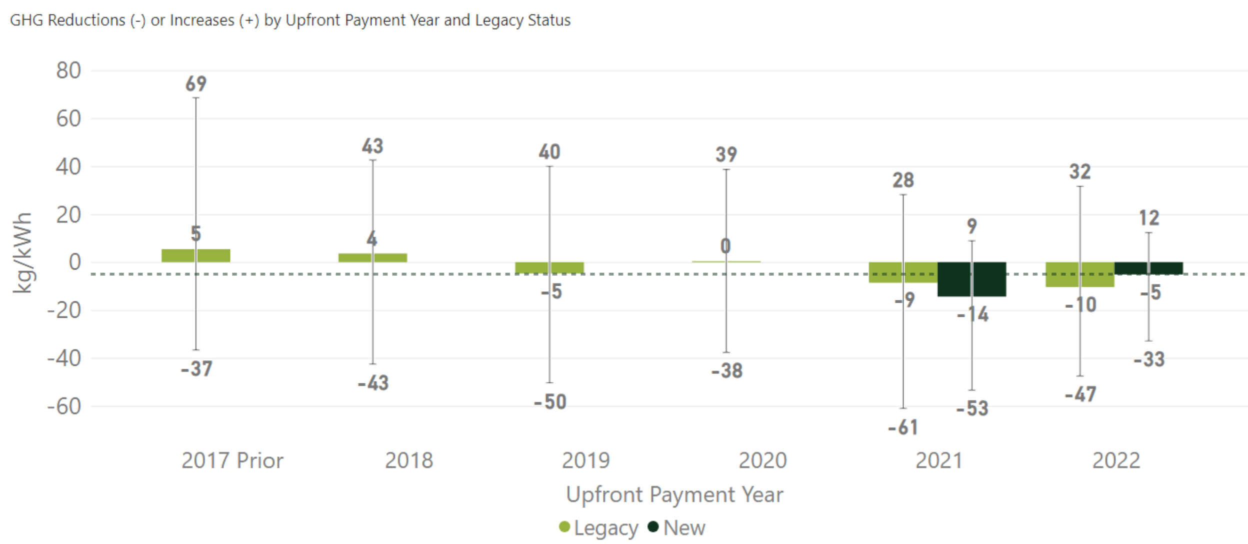


Figure 6-118 below combines the above project-specific scatterplots into average emissions increases (+) or reductions (-) for legacy status and upfront payment year in 2022. Given lag times between program application submittal, PA review, inspection, interconnection, and ultimate incentive payment, new projects don't emerge in the program – as paid in upfront incentive – until 2021. The range in emissions reductions are well captured here as well as above in the scatterplot. In 2022, legacy projects receiving upfront payments in 2020 or prior, increased emissions, on average. For systems paid in 2021 and 2022, we observe a shift from average emissions increases to reductions – both from legacy systems and new systems. Combined across upfront payment year, legacy

Legacy Status	Paired	kg GHG/kwh
Legacy	PV Paired	-14.3
New	PV Paired	-12.6
Legacy	Standalone	5.4
New	Standalone	-4.7
Total		**-3.1**

systems decreased GHG emissions by roughly 2.6 kg/kWh capacity, and new systems decreased emissions by 5.9 kg/kWh, on average. The inset figure further details overall nonresidential emissions by legacy status and PV pairing. Standalone legacy projects represent an older vintage of projects which were increasing emissions in 2022.

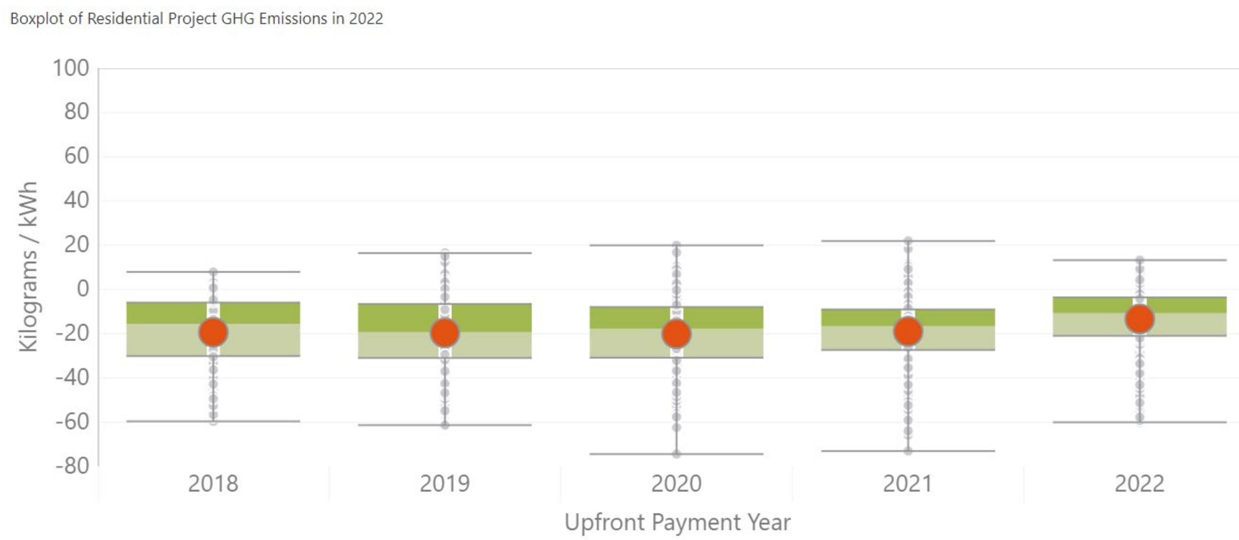
FIGURE 6-118: NONRESIDENTIAL GHG EMISSIONS BY PAYMENT YEAR AND LEGACY STATUS



Residential

Figure 6-119 presents the range in GHG emission reductions (-) or increases (+) for the sample of residential projects analyzed as part of the 2022 impact evaluation. Boxplots are disaggregated by the year in which an SGIP energy storage project received their incentive payment. We observe significant GHG emissions reductions across the residential sector, independent of the length of time the system has been installed and operable. Average, median, and quartile estimates reveal some variability with some emissions reductions reaching over 70 kg/kWh and increases extending to above 20 kg/kWh. Despite some project variance, the upper quartile for each payment year grouping is negative which signals that 75% or more projects were reducing emissions in 2022. The average reduction across all payment years is roughly 18 kg/kWh.

FIGURE 6-119: EMISSIONS (KILOGRAMS GHG/KWH) FOR RESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR



From a GHG perspective, the value of charging during on-site PV generating hours cannot be overstated. Furthermore, discharging in late afternoon and early evening, when on-site generation and grid-level renewable generation wanes, provides systems with an opportunity to reduce emissions during high marginal emission periods. These high marginal emission periods also generally fall within newer on-peak TOU periods, so customers also have an opportunity to realize bill savings if discharging is coincident with high marginal emissions periods.

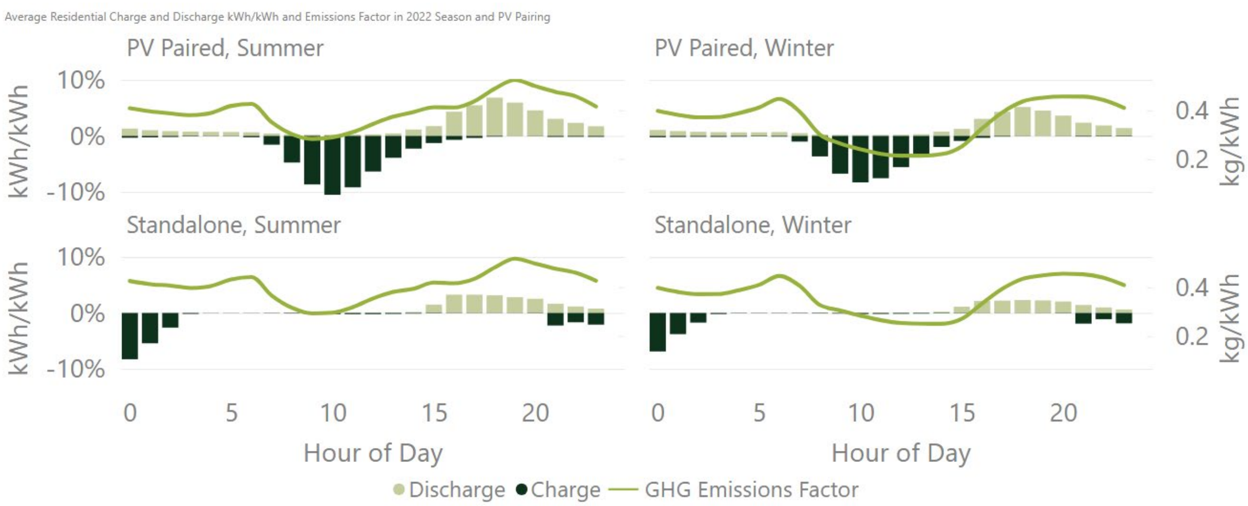
Figure 6-120 displays the average charge and discharge kWh as a percent of system capacity for PV paired and standalone residential systems – throughout summer and winter months[42] – along with the average marginal emissions shape. In winter months, marginal emissions are lowest during daylight hours when grid-scale renewables are generating and demand for A/C loads is far less than in summer months. In the summer, marginal emissions are highest during the early morning and, most significantly, throughout the early evening hours on most days. Paired residential systems are charging in the morning and early afternoon from on-site PV which aligns well with lower marginal emissions. Discharge is most prevalent late in the afternoon, and during on-peak hours – suggesting TOU arbitrage is a primary operating mode. However, solar self-consumption is also evident in the discharge outside on-peak hours, albeit at much lower magnitudes.

While a small percentage of residential systems are standalone (3%), their performance is sufficiently different from paired systems – especially charging behavior – to warrant discussion. The two lower exhibits in Figure 6-120 reveal discharge throughout on-peak hours for standalone systems – like paired

42 Summer in this context is defined as June, July, August and September. All other months represent Winter.

systems, but at much lower magnitudes – and charge beginning after the on-peak period, with the most significant charging occurring after midnight (based on customers on rates with a super off-peak beginning then). Emissions throughout these hours, on average, are lower than they are during on-peak hours, but greater than they are when paired systems are charging.

FIGURE 6-120: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY SEASON AND PV PAIRING



It's important to note, residential TOU on-peak periods generally run from 4 pm to 9 pm. Marginal emissions are highest during only a portion of that on-peak period on most days, so optimizing for the greatest emissions reductions can be achieved while maintaining bill savings benefits. Most residential systems are two- or three-hour batteries, so a system might discharge beginning at 4pm to reduce billed energy imports. If discharged at full capacity, the battery would be exhausted before 7pm and likely sooner if the SOC threshold is 20 or 30%. If marginal emissions peak during 7 pm or 8 pm, the system has lost the opportunity to maximize emissions reductions. If discharge was held to 7 pm or 8 pm the customer could realize virtually identical bill savings, with the added benefit of discharging during a period of greater grid stress and emissions.

Some of this nuanced behavior is captured below in Figure 6-121, where the above figure is replicated for PV paired systems only and disaggregated further by equipment manufacturer. This figure is similar to Figure 6-102, except that here the behavior is shown by season instead of only on peak days. But similar patterns emerge. Overall, charge timing is consistent across manufacturers with summer magnitudes greater than winter as systems are utilized more. Equip A, C, and D exhibit most discharge throughout on-peak hours, with some discharge extending thereafter. This suggests a blend of arbitrage and self-consumption across the respective fleets. Equip B exhibits different behavior with discharge occurring in

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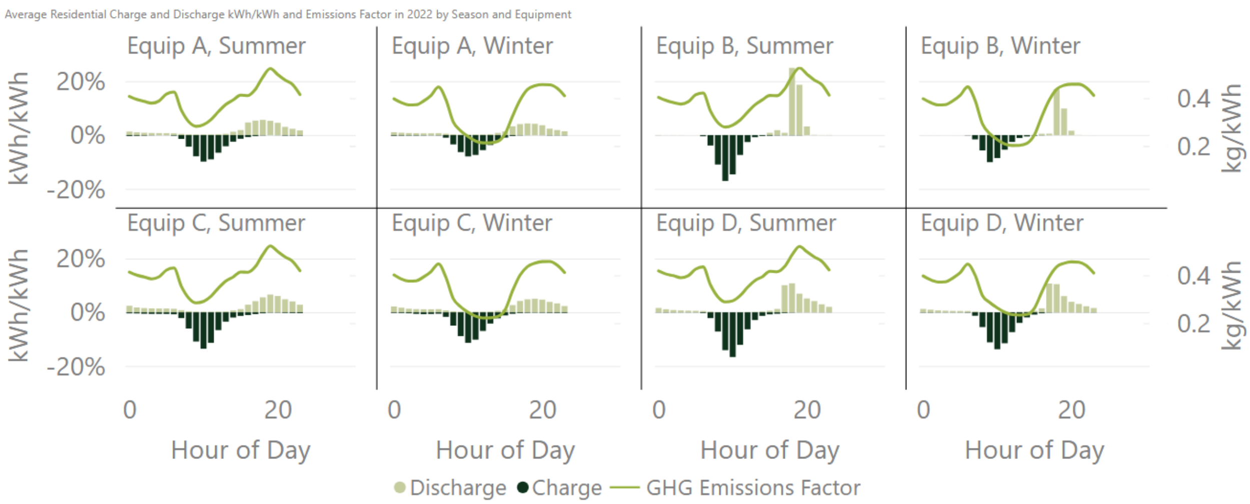
the 6pm to 8pm hours of the on-peak period almost exclusively in 2022.[43] In previous evaluation years, this fleet was discharging identical to this, but during the 4pm to 6pm hours. We observe a fleet-level switch in timing of discharge for this cohort in the summer of 2021, and this behavior extended throughout the entirety of 2022. The new dispatch signal aligns better with marginal emissions throughout summer months than the previous one.

FIGURE 6-121: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY SEASON AND EQUIPMENT



Well utilized PV paired residential systems are generally conducting 1) TOU arbitrage without export, 2) TOU arbitrage with export – either regularly or exclusively during specific times like an ELRP event, 3) self-consumption, or 4) some combination of all. We also observe under-utilization – not at a fleet or sector level – but from project to project. Idle, under-utilized systems are likely servicing a load much less than the capacity of the system or are in exclusive back-up mode, which is not allowed within the SGIP. We also observe some systems paired with PV that were charging from solar in 2021, but begin charging the battery overnight in 2022, perhaps to take advantage of extremely low off-peak EV billed rates. This latter behavior is far more infrequent and is like that of standalone systems, but the change in charge timing has a dramatic effect on system emissions.

The prevalent residential operating modes are presented below in Figure 6-122. Self-consumption is the most frequently observed dispatch behavior in the sample of residential PV paired systems, followed by TOU arbitrage. The mode referred to as “Nothing” combines systems that are under-utilized or remained idle throughout the entirety of the metering period (roughly 4% of the sample).

43 Roughly 60% of kWh capacity, on average, is discharging throughout this time.

FIGURE 6-122: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY OPERATING MODE

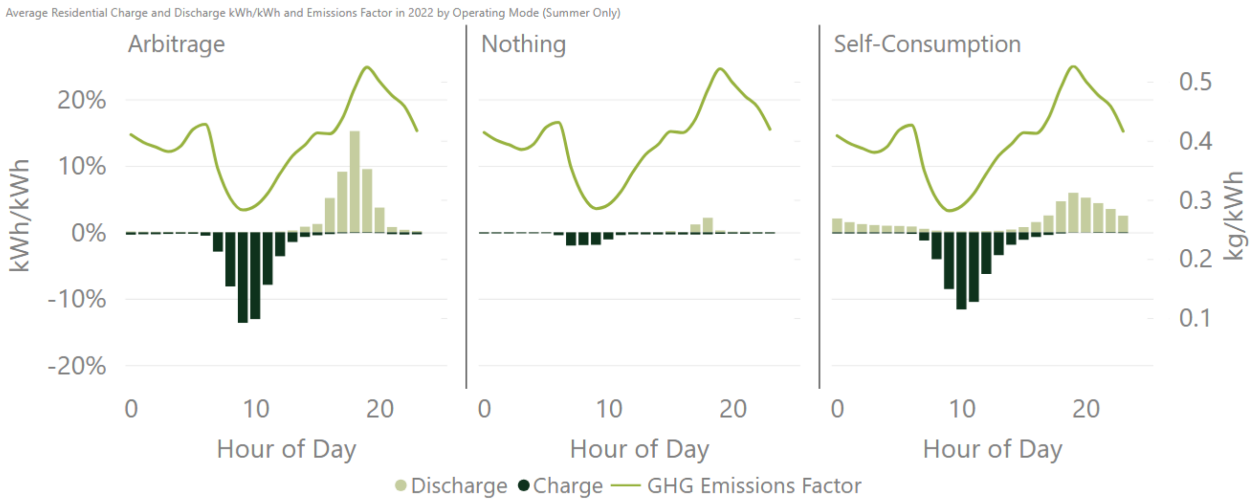
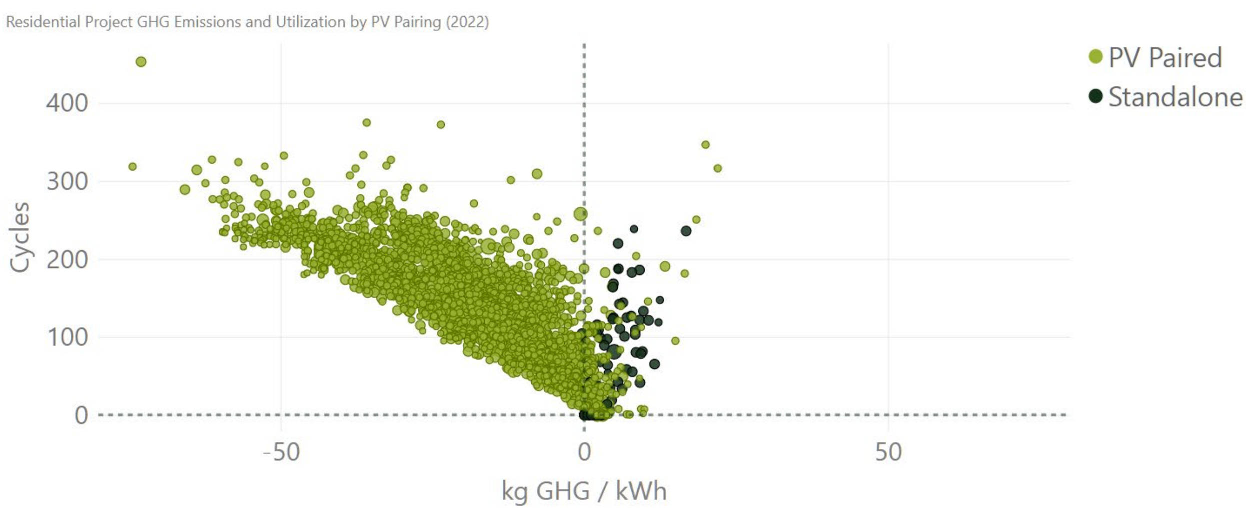


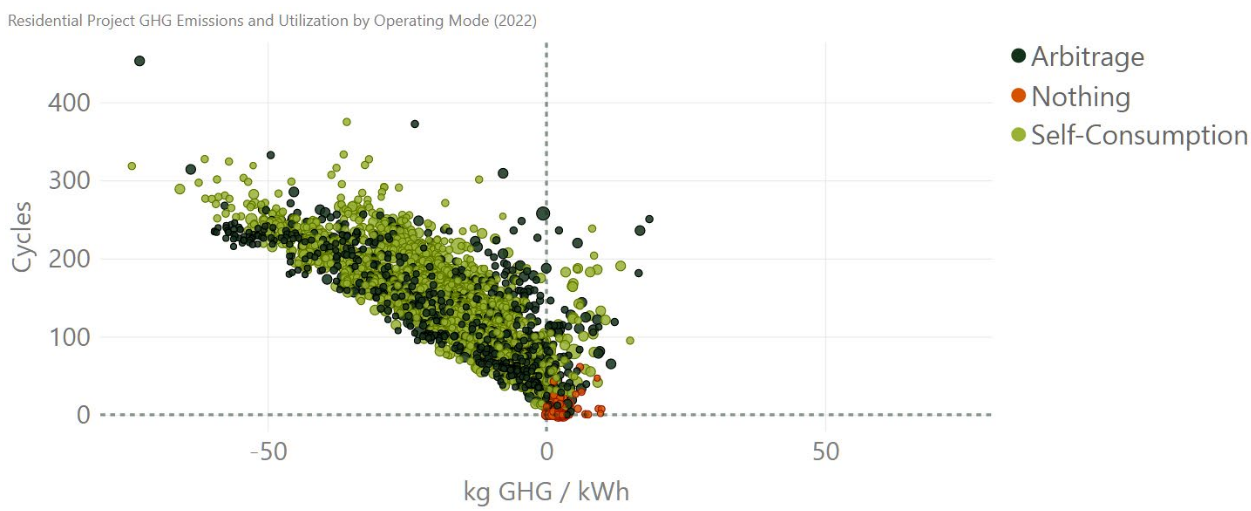
Figure 6-123 presents the project specific annual GHG emissions impacts for each residential project in 2022 by PV pairing. Emissions in kg GHG/kWh of capacity are represented on the horizontal axis with emissions reductions moving negative to left and increases moving right along the axis. Annual cycles, a proxy for system utilization, are also plotted on the vertical axis to highlight the correlation between greater utilization and emissions magnitudes. PV paired systems are almost invariably reducing emissions (if well utilized) and standalone systems are all increasing emissions. The emissions differentials between charging overnight and discharging on-peak are not sufficient for standalone systems to realize emissions reductions like observed with PV paired systems charging from on-site PV during much lower emissions hours.

FIGURE 6-123: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY PV PAIRING



Project emissions for PV paired systems conducting arbitrage, self-consumption or doing nothing (a proxy for under-utilization or backup) are presented below in Figure 6-124. There are no discernable differences in emissions from systems performing TOU arbitrage versus self-consumption, although systems conducting the latter are generally utilized more often. Idle systems all lead to small increases in emissions as system parasitic loads accumulate over the course of the year.

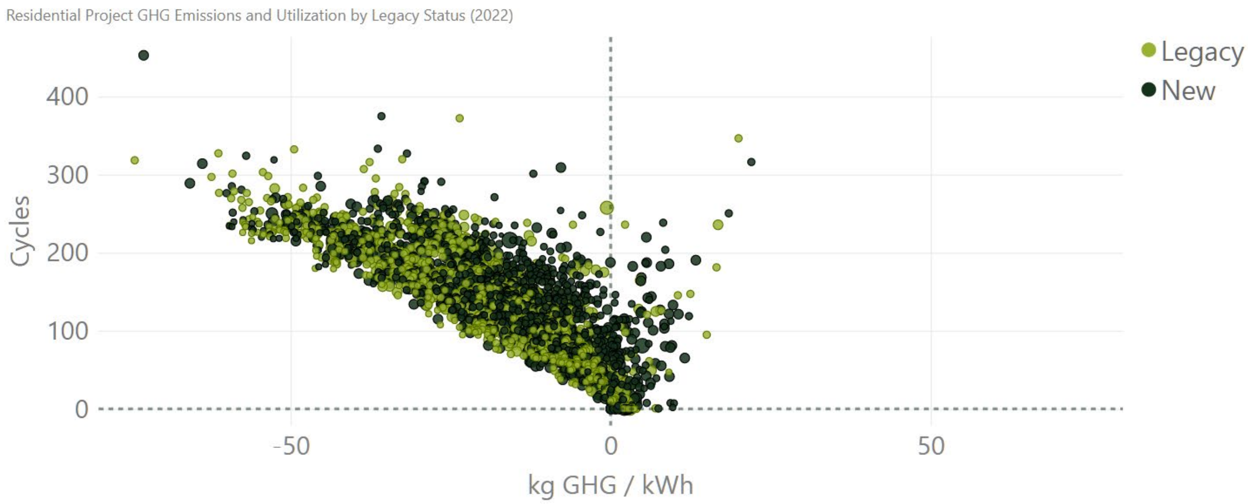
FIGURE 6-124: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY OPERATING MODE



Finally, Figure 6-125 presents the emissions based on project legacy status. New residential projects must enroll in an SGIP-approved time-of-use (TOU) or electric vehicle rate and project developers are encouraged to communicate with legacy project customers about changing over to a time-varying or EV rate if they are not already on one.

Most standalone systems received incentives in 2021 or 2022 and are non-legacy, so many of the projects with lower utilization and increased emissions represent that cohort. Lower utilization for some new projects could also be a function of the shorter metering periods. A project receiving an incentive in October of 2022 would be considered new (or non-legacy) if the RRF was submitted on or after 4/1/2020. Verdant would only be evaluating partial year impacts for those systems during the period immediately following that payment date. All legacy projects have been paid prior to the outset of 2022, so full calendar year impacts are generally available for all those systems.

FIGURE 6-125: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY LEGACY STATUS



Cross-Year Performance Impact Comparisons (2021 to 2022)

Verdant also compared the greenhouse gas emissions performance developed for CY 2021 (provided separately in Appendix C) to those in 2022. These comparisons were made for system-level utilization to highlight any potential changes in GHG emissions from one year to the next for systems operational throughout both years. Figure 6-126 and Figure 6-127 present those comparisons for the nonresidential and residential sectors, respectively. Any point on the figure above the line separating the light and gray areas (and left of zero) represents a system exhibiting greater GHG emissions in 2022 than 2021 (and vice versa). Generally, nonresidential systems that increased emissions in 2021 also increased emissions in 2022. Residential systems were decreasing emissions in both years and we observe increased project-level reductions in 2022 compared to 2021.

FIGURE 6-126: NONRESIDENTIAL CROSS-YEAR GREENHOUSE GAS EMISSIONS COMPARISON (2021 TO 2022)

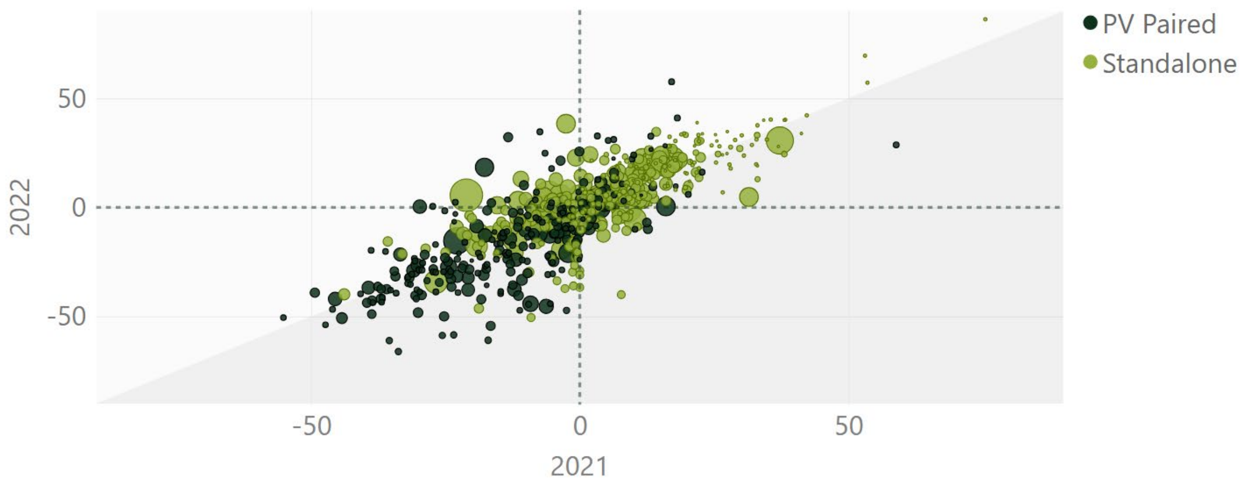
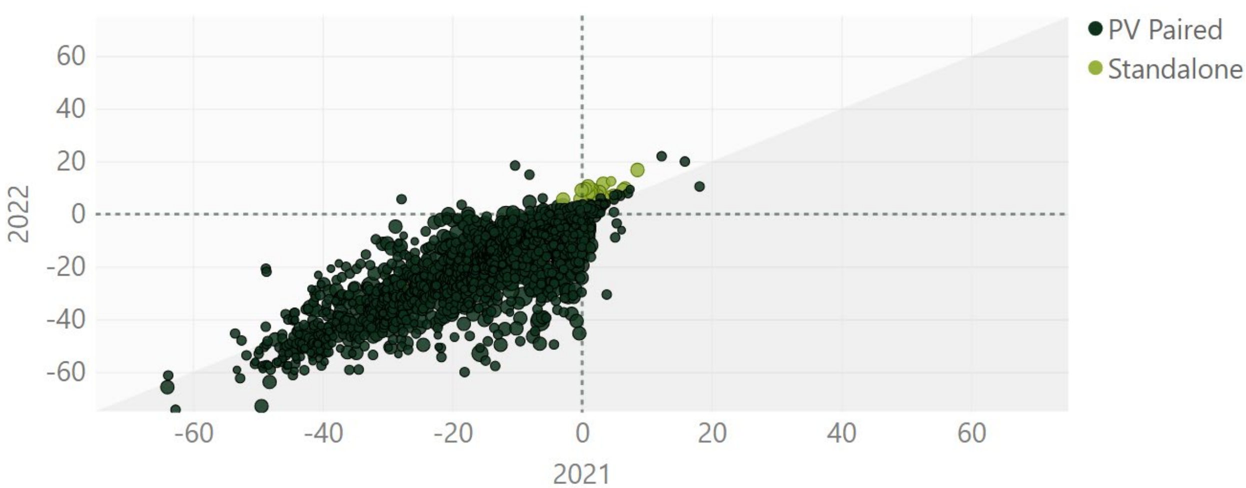


FIGURE 6-127: RESIDENTIAL CROSS-YEAR GREENHOUSE GAS EMISSIONS COMPARISON (2021 TO 2022)



GHG Impact Summaries

Below we summarize the GHG impacts discussed above for both the nonresidential and residential sectors, respectively. Summaries are provided by different domains of interest, including by PA, PV pairing, legacy status, and upfront payment year.

FIGURE 6-128: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY PA

PA	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
CSE	145	242	550	-1.3
PG&E	254	253	623	-3.3
SCE	425	298	662	-3.7
SCG	40	393	854	-3.0
Overall	**864**	**280**	**641**	**-3.2**

FIGURE 6-129: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA

PA	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
CSE	393	8	21	-23.7
PG&E	1591	8	21	-10.6
SCE	788	7	19	-25.3
SCG	36	8	22	-24.4
Overall	**2808**	**8**	**20**	**-16.5**

FIGURE 6-130: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY PV PAIRING

On-site Generation	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
PV Paired	315	237	515	-11.9
Standalone	549	304	713	0.4
Overall	**864**	**280**	**641**	**-3.2**

FIGURE 6-131: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA BY PV PAIRING

On-site Generation	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
PV Paired	2716	8	20	-17.4
Standalone	92	10	26	3.6
Overall	**2808**	**8**	**20**	**-16.5**

FIGURE 6-132: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY LEGACY STATUS

Legacy Status	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
Legacy Projects	727	286	585	-2.0
New Projects	137	247	939	-7.0
Overall	**864**	**280**	**641**	**-3.2**

FIGURE 6-133: SUMMARY OF RESIDENTIAL GHG IMPACTS BY LEGACY STATUS

Legacy Status	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
Legacy Projects	1050	7	18	-18.9
New Projects	1758	8	22	-15.3
Overall	**2808**	**8**	**20**	**-16.5**

FIGURE 6-134: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY UPFRONT PAYMENT YEAR

Upfront Payment Year	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
2017 Prior	108	353	707	4.0
2018	92	269	536	1.1
2019	231	187	386	-7.9
2020	102	368	798	0.8
2021	158	345	731	-5.1
2022	173	252	819	-6.4
Overall	**864**	**280**	**641**	**-3.2**

FIGURE 6-135: SUMMARY OF RESIDENTIAL GHG IMPACTS BY UPFRONT PAYMENT YEAR

Upfront Payment Year	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
2018	150	6	16	-18.6
2019	277	7	16	-18.8
2020	478	7	18	-18.7
2021	1090	9	23	-17.4
2022	813	8	20	-13.0
Overall	**2808**	**8**	**20**	**-16.5**

6.4.2 Generation

Passage of SB 412 in 2009 required the CPUC to establish GHG goals for the SGIP. Therefore, most of the generation projects in the population today are designed with GHG goals in mind. Non-renewable projects, in general, were found to increase emissions during 2022. There were a few non-renewable projects with high levels of heat recovery that were found to decrease emissions, and overall, gas turbines were one combustion non-renewable technology that overall reduced emissions. Renewably fueled projects reduced emissions, with systems with vented baselines contributing to the highest reductions in emissions. Non-fueled technologies like wind and pressure reduction turbines also reduced emissions.

The projects whose impacts are observed in this section include all projects with metered data for all applicable streams of data. For example, wind turbine projects only require energy generation data. Combustion technologies without heat recovery would only require energy generation and fuel consumption data. However, combustion technologies with fuel data would require energy generation, fuel consumption, and heat recovery data. Heat recovery is notoriously difficult to meter. The limited quantity of metered heat recovery data is used in the calculation of population-level GHG estimates for CHP systems using methods discussed in Appendix D.

The GHG impact analysis is limited to carbon dioxide (CO_2) and CO_2 equivalent (CO_2eq) methane (CH_4) emissions impacts associated with SGIP projects. The discussion is organized into the following subsections:

- Methodology Overview and Summary of Environmental Impacts
- Non-renewable Generation Project Impacts
- Renewable Biogas Generation Project Impacts
- Waste Gas and Non-Fueled Project Impacts

The scope of this analysis is further limited to the operational impacts of SGIP projects and does not discuss any lifecycle emissions impacts that occur during the manufacturing, transportation, and construction of SGIP projects. A more detailed discussion of the environmental impacts methodology is included in Appendix D.

Background and Baseline Discussion

Emission impacts are calculated as the difference between the emissions generated by SGIP projects and baseline emissions that would have occurred in the absence of the program. The sources of these emissions (generated and avoided) vary by technology and fuel type. For example, all distributed generation technologies avoid emissions associated with displacing central station grid electricity, but only those that recover useful heat may avoid emissions associated with displacing boiler use.

Grid Electricity Baseline

The passage of SB 412 established a maximum GHG emissions rate for SGIP generation technologies. Beginning in 2011, eligibility for SGIP generation projects was limited to projects that did not exceed an emissions rate of 379 kg CO_2/MWh over ten years. Later, the CPUC revised the maximum GHG emissions rate for eligibility to 350 kg CO_2/MWh over ten years for projects applying to the SGIP in 2016.

When developing these emission factors for eligibility, the CPUC and the SGIP PAs must look forward and forecast what baseline grid conditions will look like during an SGIP project's life. These forecasts must make assumptions about power plant efficiencies and the useful life of SGIP projects. By contrast, an impact evaluation has the benefit of being backward-looking and can leverage historical data to quantify the grid electricity baseline. Consequently, the avoided grid emissions rates used in this impact evaluation report to assess project performance are different than the avoided grid emissions factors used to screen SGIP applications for program eligibility requirements. This evaluation relies on avoided grid emissions rates developed by WattTime as part of the SGIP GHG Signal efforts.[44]

Non-Renewable Generation Project Greenhouse Gas Impacts

SGIP non-renewable generation projects include fuel cells (CHP and electric-only), gas turbines, internal combustion engines, and microturbines. These include those directed biogas projects which have met their contractual procurement requirements and are assumed to no longer procure renewable fuel. These projects are powered by natural gas and are used to generate electricity to serve a customer's load. These projects produce emissions that are proportional to the amount of fuel they consume. In the absence of the program, the customer's electrical load would have been served by the electricity distribution company. If SGIP projects only served electrical loads, they would need to generate electricity more cleanly than the avoided marginal grid generator to achieve GHG emission reductions.

CHP projects recover waste heat and use it to serve on-site thermal loads, like a customer's heating or cooling needs. In the absence of the SGIP, a heating end-use is assumed to be met by a natural gas boiler, and the cooling end-use met with an electric chiller. Natural gas boilers generate emissions associated with the combustion of gas to heat water. The emissions associated with electric chillers are due to the central station plant that would have generated the electricity to run the chiller. Emissions impacts are

[44] The real-time marginal GHG emissions signal developed by WattTime represents the compliance signal for this evaluation and the SGIP, in general. These data are publicly available here: https://sgipsignal.com/.

the difference between the SGIP emissions and those avoided emissions. Metered non-renewable gas turbines were found to reduce emissions due to the high rate of heat recovery in gas turbines.

FIGURE 6-136: OBSERVED NON-RENEWABLE PROJECT GREENHOUSE GAS IMPACTS RATES BY TECHNOLOGY TYPE

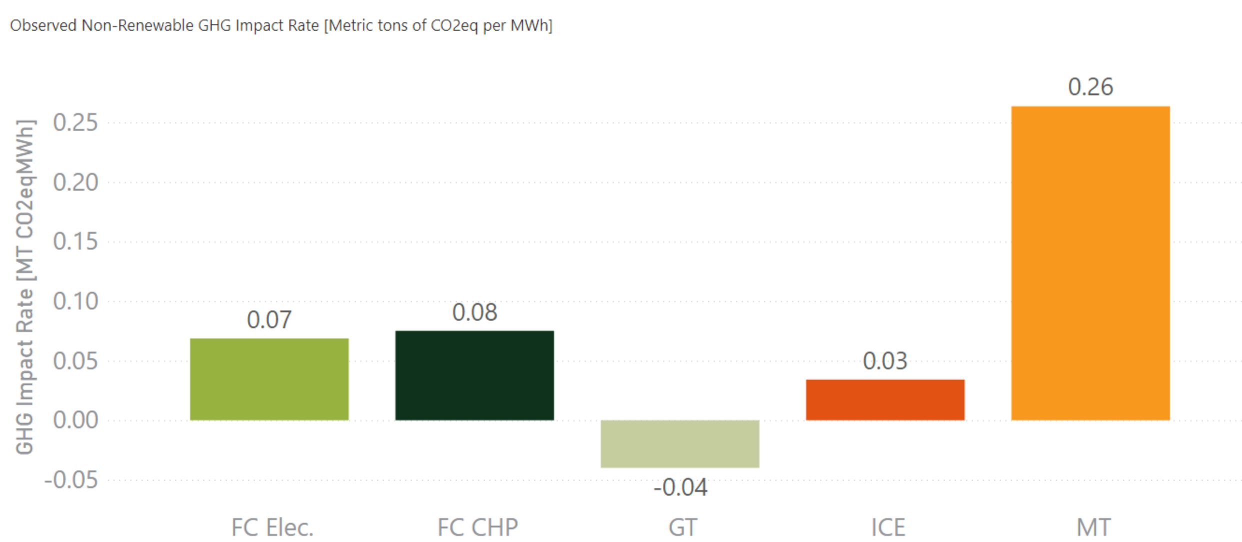


Table 6-5 shows the impact rates of the individual contributors to the GHG impact calculations. Non-renewable technologies have a higher emissions rate than the electrical power plants that they avoid (A > B). Even when accounting for the heating and cooling services avoided, the emissions impact (F) is generally higher, relative to the conventional energy services baseline.

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TABLE 6-5: OBSERVED NON-RENEWABLE PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE [METRIC TONS OF CO_{2EQ} PER MWH]

Equipment Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Cooling Services [D]	Total Avoided Emissions [E = B+C+D]	Emissions Impact [F=A-E]
Fuel Cell Electric	0.42	0.35	0	0	0.35	0.07
Fuel Cell CHP	0.49	0.35	0.07	0.00	0.42	0.08
Gas Turbine	0.58	0.34	0.28	0.00	0.62	-0.04
Internal Combustion Engine	0.65	0.34	0.26	0.01	0.61	0.03
Microturbine	0.65	0.33	0.02	0.04	0.39	0.26
Total	**0.53**	**0.34**	**0.18**	**0.00**	**0.53**	**0.00**

Figure 6-137 shows the range of GHG impact rate for each project by equipment type, for 2022. Fuel cells all increased emissions, while impact rates for gas turbines, internal combustion engines, and microturbines varied, with some systems increasing emissions and other decreasing emissions. Only all-electric fuel cells were not recovering heat, and even though all other systems recovered heat, only a few of the gas turbines and internal combustion engines operating on non-renewable fuel were found to reduce greenhouse gas emissions.

FIGURE 6-137: OBSERVED NON-RENEWABLE PROJECT-LEVEL GREENHOUSE GAS IMPACTS TECHNOLOGY TYPE

Renewable Biogas Project Impacts

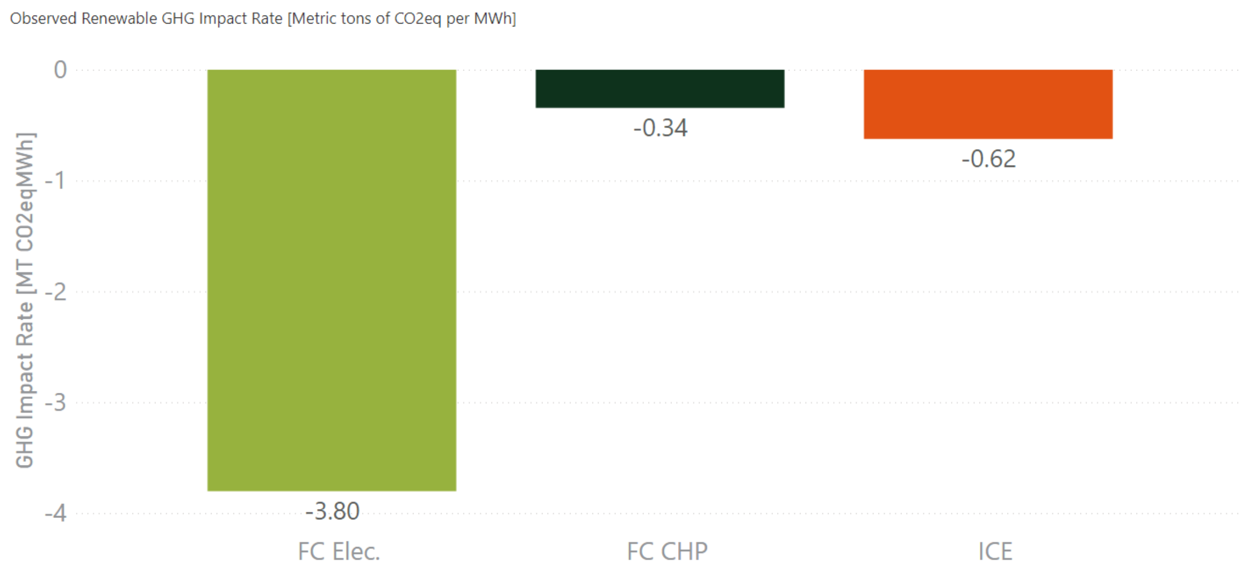
SGIP renewable biogas projects include CHP fuel cells, internal combustion engines, microturbines, and gas turbines. About 15% of the total SGIP rebated capacity is fueled, at least partially, by renewable biogas. Sources of biogas include landfills, water resource and recovery (WRRF), dairies, and food processing facilities. Analysis of the emission impacts associated with renewable biogas SGIP projects is more complex than for non-renewable projects. This complexity is due, in part, to the additional baseline component associated with biogas collection and treatment in the absence of the SGIP project installation. Also, some projects generate only electricity while others are CHP projects that use waste heat to meet site heating and cooling loads. Consequently, renewable biogas projects can directly impact emissions the same way that non-renewable projects can, but they also include emission impacts caused by the treatment of the biogas in the absence of the program.

Renewable biogas SGIP projects capture and use biogas that otherwise may have been emitted into the atmosphere (vented) or captured and burned (flared). By capturing and utilizing this gas, emissions from venting or flaring the gas are avoided. The concept of avoided biogas emissions is further explained in Appendix D.

When reporting emissions impacts from different types of greenhouse gases, total GHG emissions are reported in terms of metric tons of CO_2 equivalent (CO_2eq) so that direct comparisons can be made across technologies and energy sources. On a per mass unit basis, the global warming potential of CH_4 is 25 times that of CO_2. The biogas baseline estimates of vented emissions (CH_4 emissions from renewable SGIP facilities) are converted to CO_2eq by multiplying the metric tons of CH_4 by 25. In this section, CO_2eq emissions are reported if projects with a biogas venting baseline are included. Otherwise, CO_2 emissions are reported.

The 2022 GHG performance of renewably fueled biogas SGIP projects is summarized below in Figure 6-138 by technology type and biogas baseline. CHP fuel cells, internal combustion engines, microturbines, and gas turbines are all deployed in locations that would have otherwise flared biogas. Internal combustion engines were the only technology deployed at locations, such as dairies, which would have otherwise vented biogas. Due to the vented baseline for many internal combustion engines, this technology demonstrated both the greatest GHG avoided impact rate, along with the greatest GHG avoided impacts. All renewable fueled projects were found to decrease GHG impacts.

FIGURE 6-138: OBSERVED RENEWABLE PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE



All renewable biogas technologies reduced GHG emissions regardless of the biogas baseline type. Table 6-6 highlights the impact rates for renewably fueled technologies, separated by biogas baseline type. Technologies with flaring biogas achieved reductions between 0.34 and 0.59 metric tons of CO_2 per MWh. Internal combustion engines with vented biogas baselines achieved GHG reductions that were an order of magnitude greater, over 5 metric tons of CO_2eq per MWh. 2022 was also the first year the program saw renewably fueled all-electric fuel cells. Two of these fuel cells were generating electricity in 2022, one with a vented baseline and another with a flared baseline.

TABLE 6-6: OBSERVED RENEWABLE PROJECT GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE [METRIC TONS OF CO_{2EQ} PER MWH]

Equipment Type & Baseline Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Biogas Treatment [D]	Total Avoided Emissions [E = B+C+D]	Emissions Impact [F=A-E]
Fuel Cell Electric *(Vent)*	0.42	0.42	0	3.80	4.22	-3.80
Fuel Cell CHP *(Flare)*	0.59	0.40	0.04	0.50	0.94	-0.34
Internal Combustion Engine *(Flare)*	0.60	0.34	0.36	0.52	1.22	-0.62
Total	**0.59**	**0.36**	**0.26**	**0.71**	**1.34**	**-0.75**

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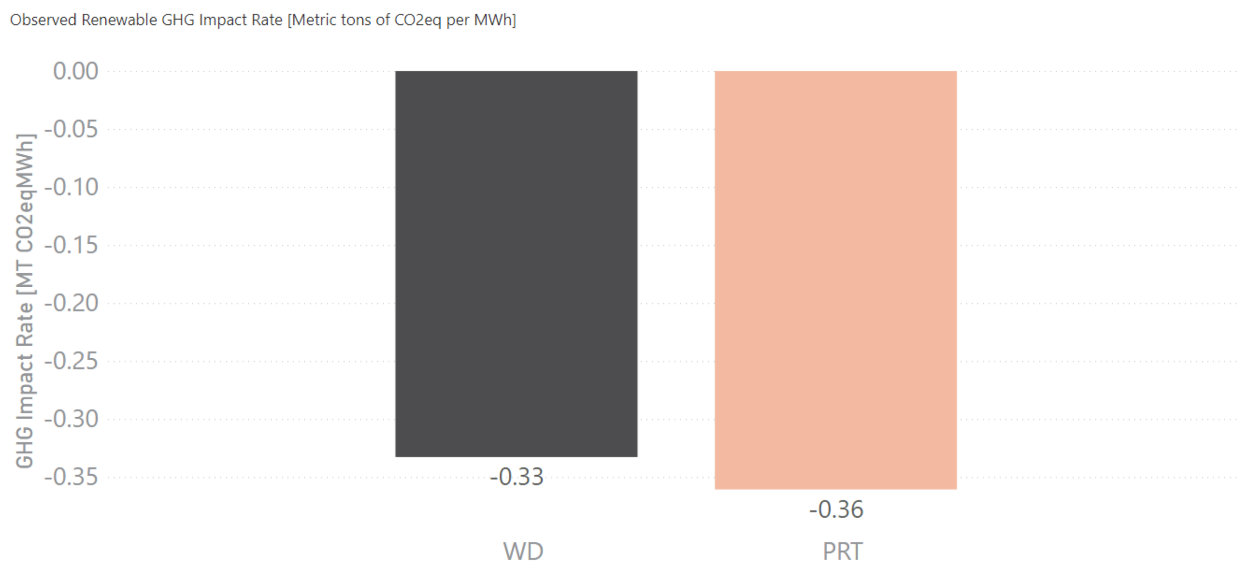
Non-Fueled Projects Impacts

Wind and pressure reduction turbine projects do not consume any type of fuel and do not recover waste heat. Their emissions reduction rates are equal to the emissions rate of the grid, as described in Appendix D. Figure 6-139 summarizes the impact rate and overall GHG impact from these projects. All non-fueled projects were found to decrease emissions.

FIGURE 6-139: OBSERVED NON-FUELED GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE



The individual impacts are shown below in Table 6-7. There are no baseline emissions for non-fueled technologies, so the emissions impact is the inverse of the electric power plant emissions for the same amount of electrical generation.

TABLE 6-7: OBSERVED NON-FUELED PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE

Equipment Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Total Avoided Emissions [E = B]	Emissions Impact [F=A-E]
Wind	0	0.33	0.33	-0.33
Pressure Reduction Turbine	0	0.36	0.36	-0.36
Total	**0**	**0.34**	**0.34**	**-0.34**

Cross-Year Performance Impact Comparisons (2021 to 2022)

Verdant also compared the greenhouse gas emissions performance developed for CY 2021 (provided separately in Appendix C) to those in 2022. These comparisons were made to highlight any potential changes in GHG emissions from one year to the next. Figure 6-140 and Figure 6-141 present those comparisons by technology type and by fuel type, respectively. Any point on the figure above the line separating the light and gray areas (and left of zero) represents a system exhibiting greater GHG emissions in 2022 than 2021 (and vice versa). The emissions impact rates for most projects did not change significantly between 2021 and 2022.

FIGURE 6-140: OBSERVED GENERATION CROSS-YEAR GHG EMISSIONS COMPARISON BY TECHNOLOGY TYPE (2021 TO 2022)

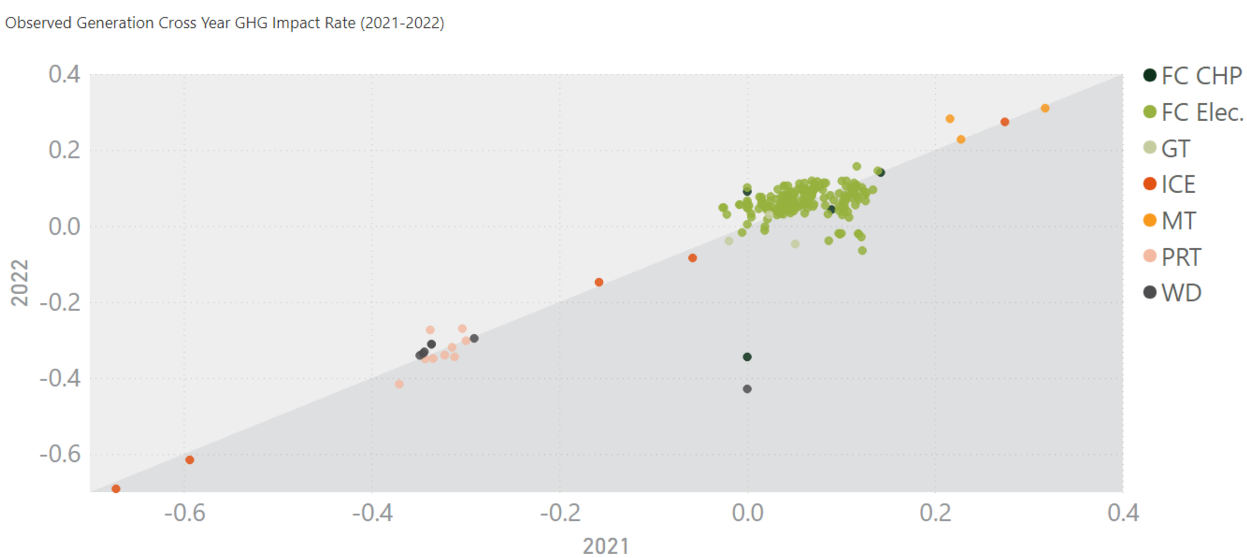
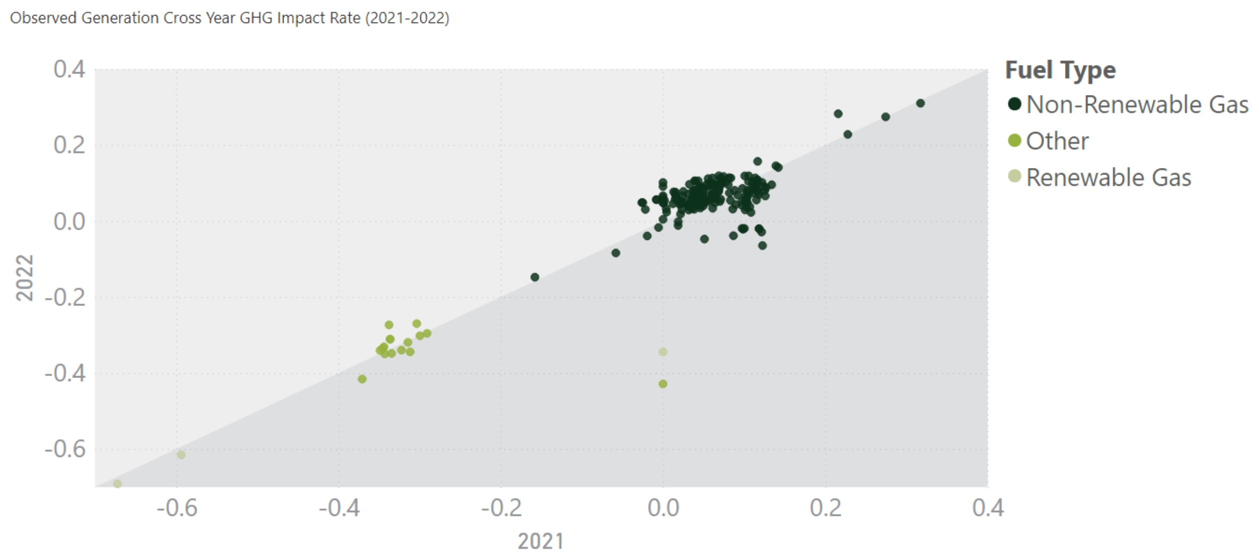


FIGURE 6-141: OBSERVED GENERATION CROSS-YEAR GHG EMISSIONS COMPARISON BY FUEL TYPE (2021 TO 2022)



GHG Impact Summaries

Below we summarize the observed GHG impacts discussed above by technology type, and fuel type.

FIGURE 6-142: SUMMARY OF NON-RENEWABLE GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg. Generation (GWh)	GHG (MT/MWh)
Fuel Cell Electric	174	111.53	0.07
Fuel Cell CHP	3	9.76	0.08
Gas Turbine	3	439.30	-0.04
Internal Combustion Engine	3	4.72	0.03
Microturbine	3	11.75	0.26
Overall	**186**	**114.77**	**0.00**

FIGURE 6-143: SUMMARY OF RENEWABLE GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg. Generation (GWh)	GHG (MT/MWh)
Fuel Cell Electric	1	0.79	-3.80
Fuel Cell CHP	1	3.14	-0.34
Internal Combustion Engine	3	9.13	-0.62
Overall	**5**	**4.35**	**-0.75**

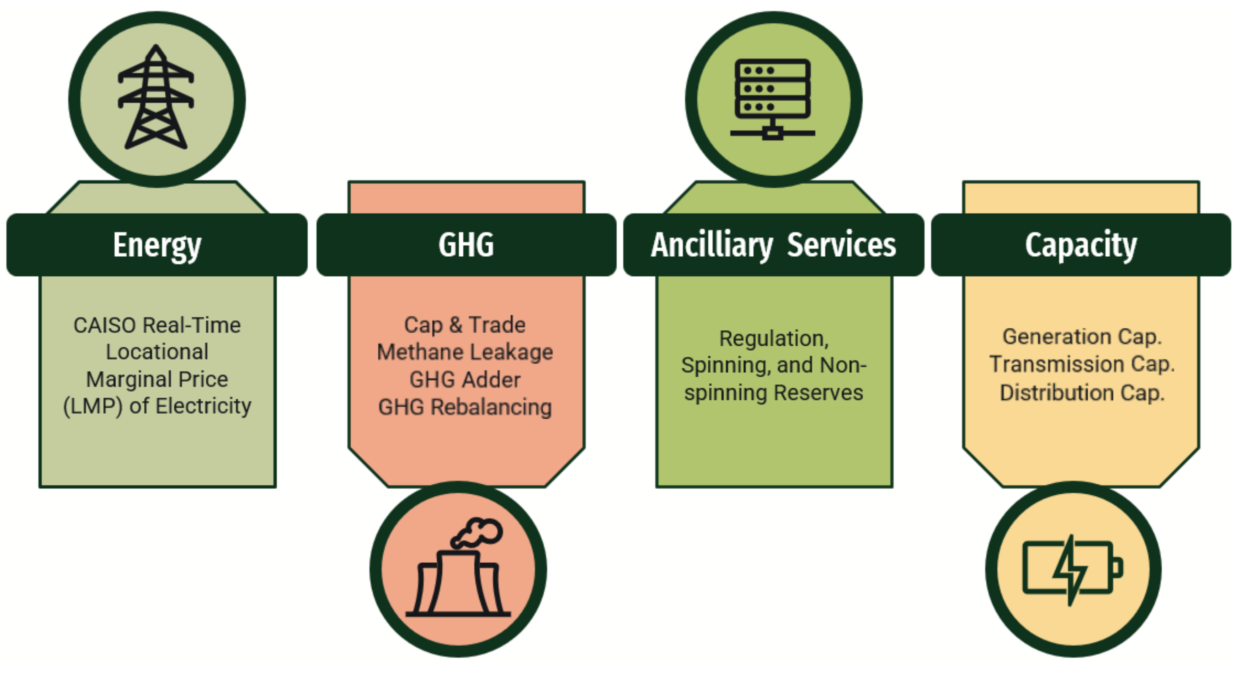
FIGURE 6-144: SUMMARY OF NON-FUELED GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg. Generation (GWh)	GHG (MT/MWh)
Wind	7	27.93	-0.33
Pressure Reduction Turbine	9	6.42	-0.36
Overall	**16**	**17.18**	**-0.34**

6.5 UTILITY MARGINAL COST IMPACTS

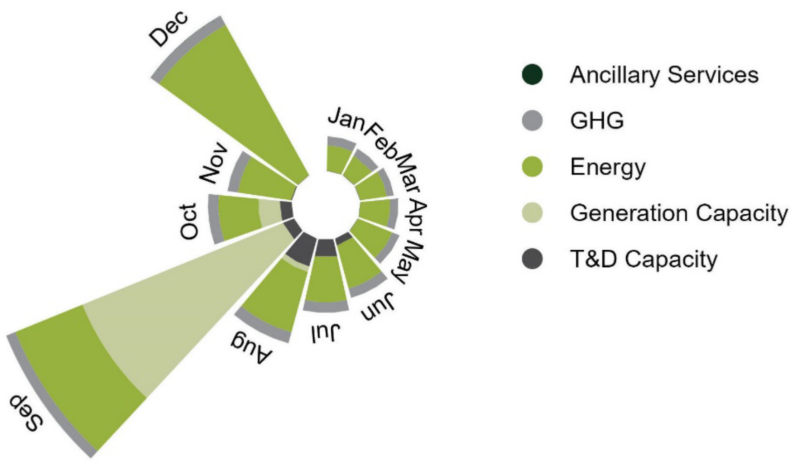
Utility marginal cost impacts for each IOU were calculated for each hour in 2021-2022. Marginal cost rates ($/kWh) used in these calculations are consistent with assumptions in the 2022 Avoided Cost Calculator (ACC2022) and with data underlying the GHG impacts analysis. The marginal GHG emissions rates introduced in the previous section were calculated by WattTime using marginal electricity, natural gas and carbon price data, as well as assumptions from the ACC. The same marginal electricity and carbon price data were used to calculate utility marginal cost impacts as were used to calculate GHG impacts. The data and assumptions used for each utility cost component are described in detail in Appendix E. The electric utility costs that were included in this analysis are shown below in Figure 6-145.

FIGURE 6-145: ELECTRIC AVOIDED UTILITY COSTS



Energy costs, GHG adder, and cap and trade costs represent the most consistent share of avoided costs throughout the year. A high-level summary of these patterns is shown in Figure 6-146, where the values represent averages across the three electric IOUs.[45] During April and May, when there are longer days and plentiful grid-scale renewable generation without the A/C demand of summer months, these costs generally are lower. However, during summer months – June through September – there are some significantly capacity-constrained hours. This is especially evident in September with the marginal generation capacity cost.

FIGURE 6-146: AVERAGE 2022 MARGINAL ELECTRIC UTIILTY COSTS BY MONTH AND COST CATEGORY



Sources: CAISO and 2022 Avoided Cost Calculator

6.5.1 Energy Storage

Previous sections have detailed the nuanced observed behavior of nonresidential and residential energy storage systems within the SGIP. When the timing and magnitude of charge and discharge follow the price signal of a customer tariff or a marginal emissions signal, storage performance can lead to customer bill savings, and avoided GHG emissions. The same is true for utility costs.

For energy storage systems to reduce utility costs, the marginal costs *avoided* during storage discharge must be greater than the marginal cost increase during storage charging. Since storage technologies inherently consume more energy during charging relative to energy discharged, the marginal cost rate must be lower during charging hours relative to discharge hours if utility cost savings are to be realized. In other words, SGIP storage systems that charge during lower marginal cost periods and discharge during higher marginal cost periods will provide a net benefit to utility systems.

45 In this exhibit, ancillary services, losses and methane leakage have been combined into an “Other”.

Nonresidential Utility Avoided Costs

The normalized utility marginal avoided costs in 2022 are shown in Figure 6-147 by electric IOU for nonresidential energy storage systems. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). The timing, magnitude and duration of nonresidential storage charge and discharge behavior provided an avoided cost benefit to all electric utilities in 2022. SGIP storage systems were charging during lower marginal cost periods – particularly systems paired with on-site PV – and discharging during higher cost periods which also coincide with billed on-peak hours and times of greater marginal emissions. Marginal costs are highest when energy prices are high, and generation capacity and transmission and distribution systems are constrained. On average, energy storage systems are discharging throughout the most constrained hours (and not charging), which occurred throughout the "heat-dome" event in early September 2022. Overall, the average marginal *avoided* cost (+) for nonresidential systems in PG&E was $20 per capacity (kWh), for SCE they were $16 and for SDG&E they were $12 per capacity (kWh). For each utility throughout the year, the much more variable generation and T&D capacity components represent the most avoided cost benefits, followed by avoided energy costs.

FIGURE 6-147: NONRESIDENTIAL AVOIDED COST $ PER CAPACITY KWH BY IOU

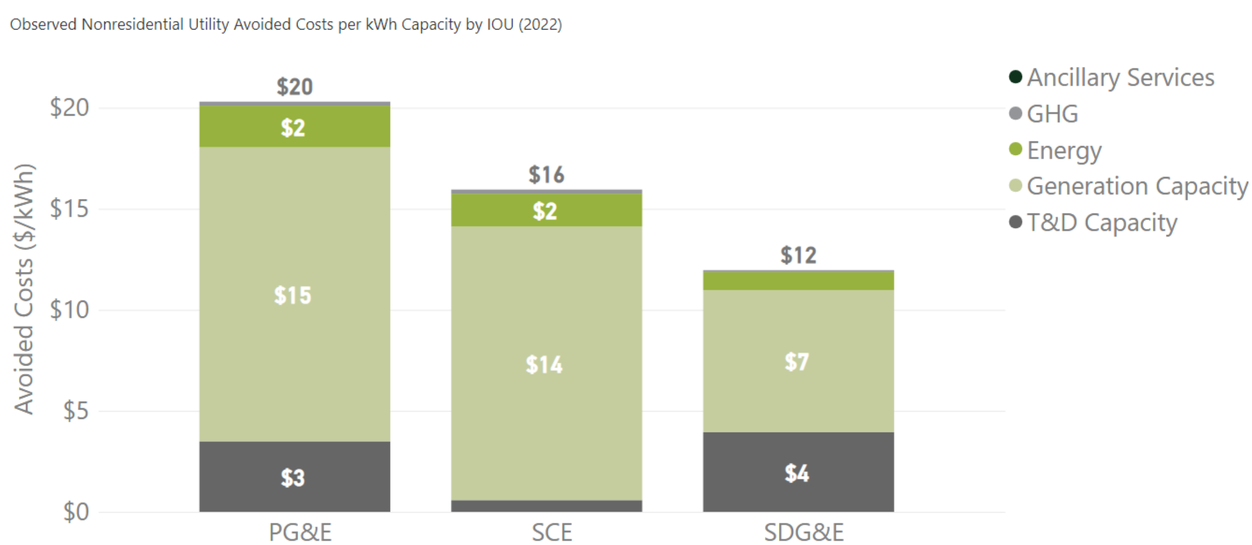


Figure 6-148 provides the distribution of nonresidential project avoided costs for 2022. Moving right along the horizontal axis from zero signals avoided cost benefits to the utility. The vertical axis ties the utilization of the system in annual cycles to the utility costs, where a correlation between greater utilization and increased utility avoided cost benefit is evident. The size of the bubble corresponds to the relative kWh size of the system, with many of the smaller systems exhibiting lower utilization and small utility cost increases from performance in 2022.

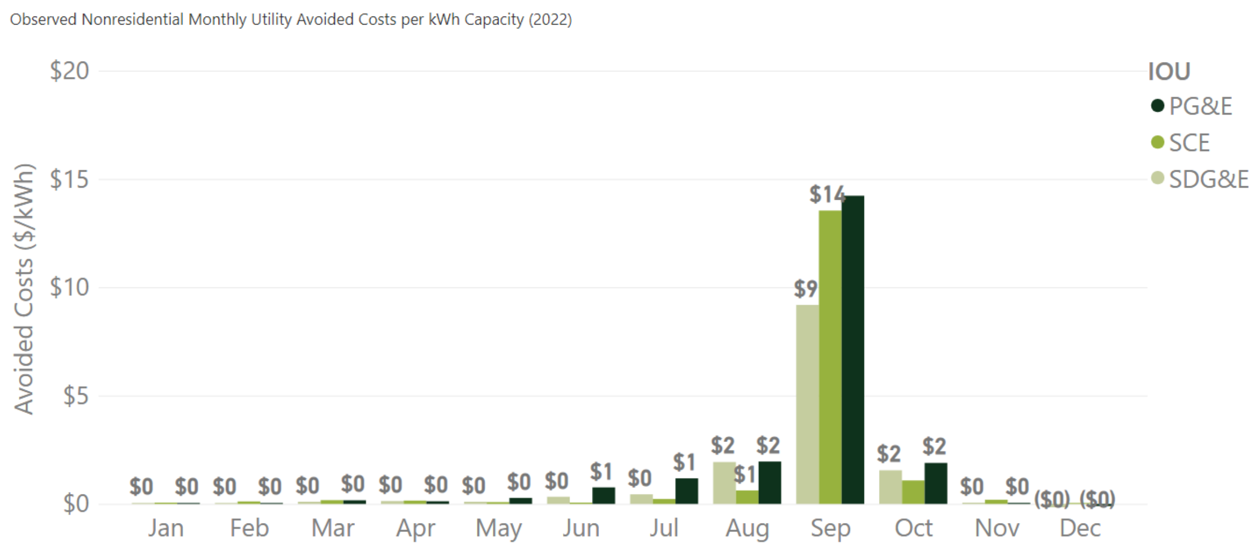
FIGURE 6-148: NONRESIDENTIAL PROJECT AVOIDED COST $ PER CAPACITY KWH BY IOU

Most of the smaller nonresidential systems were incentivized in the SGIP in earlier program years during a time when energy storage was first an eligible technology. The box plot below conveys lower avoided cost benefits across utility for systems paid incentives in 2017 and prior. Storage performance from systems installed and incentivized more recently provided greater utility cost benefit in 2022. Again, much of that benefit was captured by beneficial discharging during coincident on-peak hours, especially throughout grid constrained hours in September.

FIGURE 6-149: DISTRIBUTION OF 2022 NONRESIDENTIAL AVOIDED COSTS $ KWH BY IOU AND PAYMENT YEAR

The timing of utility avoided cost benefit is evident in Figure 6-150 which presents how those avoided cost benefits are allocated across month throughout 2022 for each IOU. Again, the marginal costs modeled in this study are highest when energy prices are high, and the CAISO system load is peaking. Most of the system cost value is captured in a small number of high-cost hours that are generation capacity constrained. These hours generally align with net peak CAISO hours, which is evident with the magnitude of savings in September relative to other months throughout the year.

FIGURE 6-150: NONRESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KW BY MONTH AND IOU



Residential Utility Avoided Costs

Prior sections of the evaluation have detailed how residential systems are being utilized for TOU arbitrage and self-consumption. When paired with on-site PV, systems are discharging exclusively on-peak or on-peak *and* to zero out delivered load. Furthermore, some systems are discharging beyond BTM consumption and exporting excess battery kWh capacity to the grid during on-peak hours. Export is standard daily practice for some groups of systems and wholly event based (ELRP, for example) for other groups.

Either way, these behaviors are advantageous from a customer bill, a system load, and GHG perspective. Given the correlation between billed on-peak hours of 4 pm – 9 pm, CAISO net loading, and marginal grid generator emissions to utility costs, observed residential system behavior in 2022 would be advantageous from an avoided utility cost perspective as well. The normalized utility marginal costs for residential systems by electric IOU are shown in Figure 6-151. Marginal avoided costs are positive (+) and marginal

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incurred costs are negative (-). Each of the three utilities realized total marginal avoided cost savings during 2022 at a greater overall magnitude than nonresidential storage systems, when normalized by kWh capacity. Overall, the average marginal *avoided* cost (+) for residential systems in PG&E territory is $24 per capacity (kWh), for SCE they were $27 and for SDG&E they were $32 per capacity (kWh). Again, most of those cost savings accrue from energy and capacity.

FIGURE 6-151: RESIDENTIAL MARGINAL AVOIDED COST $ PER KWH CAPACITY BY IOU

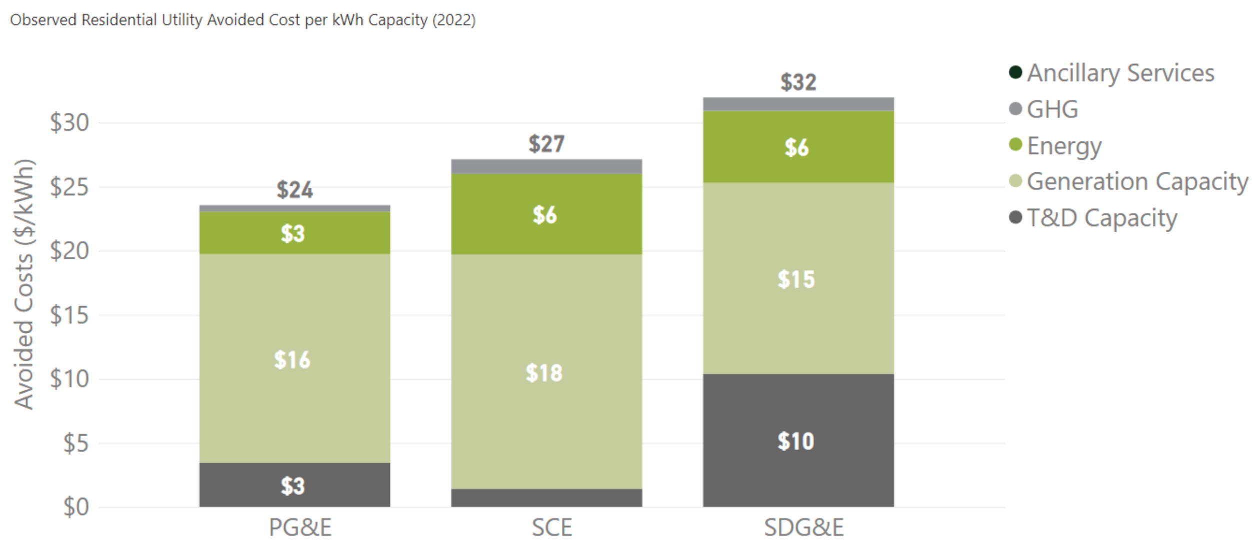
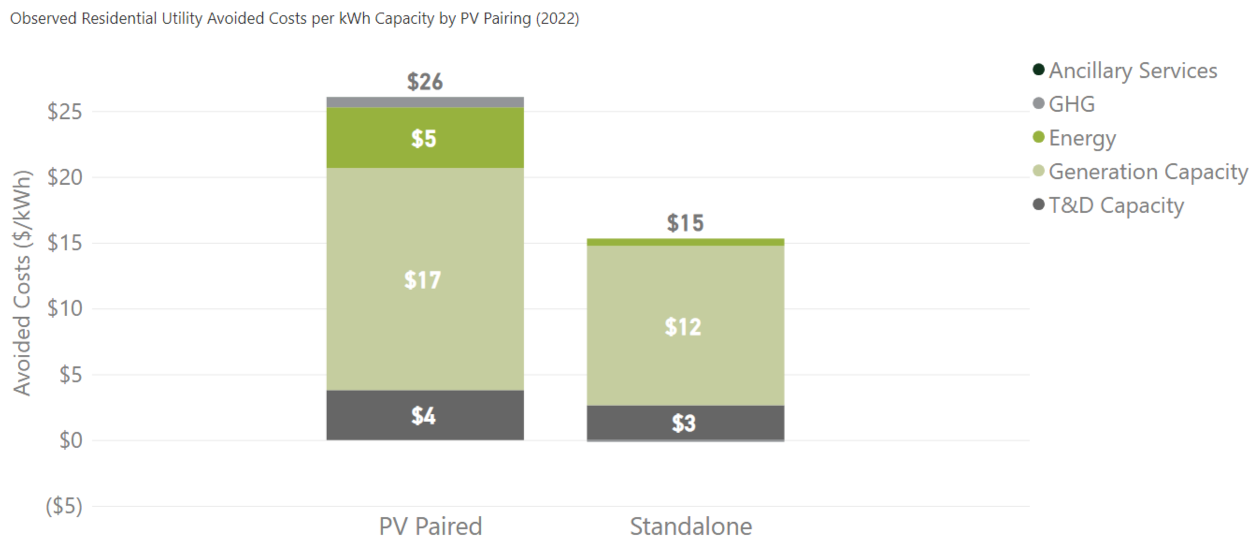


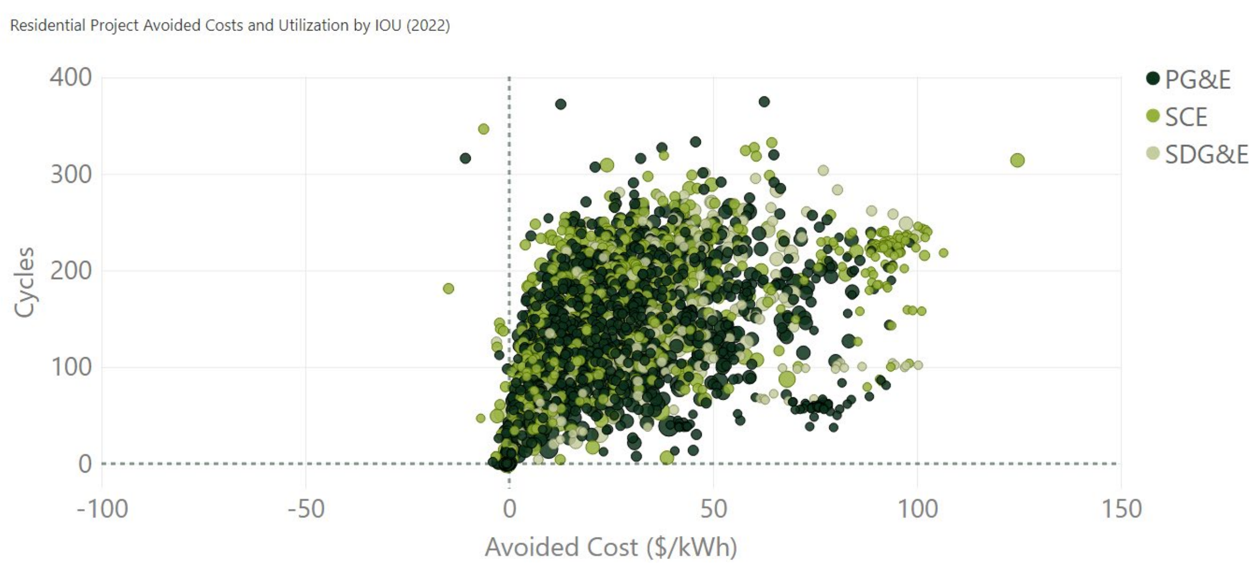
Figure 6-50 presented the greater utilization from PV paired systems relative to standalone systems. Standalone systems are conducting TOU arbitrage exclusively – discharging during the 4 pm – 9 pm peak and charging thereafter. PV paired systems discharge roughly 45% of kWh capacity, on average, throughout weekdays, whereas standalone systems discharge roughly 22%. As a result, PV paired systems provided a greater avoided cost benefit, on average, in 2022 than standalone systems (Figure 6-152).

FIGURE 6-152: RESIDENTIAL MARGINAL AVOIDED COST $ PER KWH CAPACITY BY PV PAIRING



The correlation between greater utilization and utility avoided cost benefits is presented for the residential sector in the scatterplot below in Figure 6-153. Almost all residential systems provided an avoided cost benefit in 2022 – independent of PV pairing or not – but the magnitude of benefit is aligned with greater system utilization.

FIGURE 6-153: RESIDENTIAL PROJECT AVOIDED COST $ PER CAPACITY KWH BY IOU

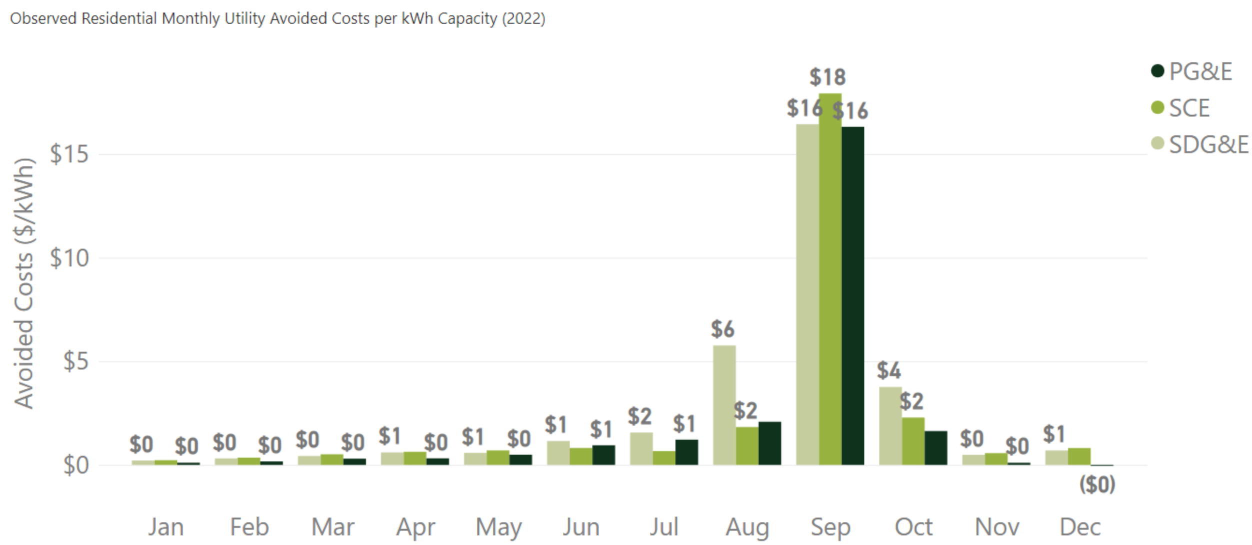


Unlike the nonresidential sector, there is little difference in performance and utility cost impacts for residential systems installed more recently. Figure 6-154 below presents inter-project variability by IOU electric service and payment year. The length of the whiskers, particularly moving upward, confirms that variability. Varying utilization across the residential project fleet, along with magnitude of discharge during some of the more costly and capacity constrained hours are greater indicators of utility avoided cost impacts than the vintage of the system or fleet.

FIGURE 6-154: DISTRIBUTION OF RESIDENTIAL AVOIDED COST $ PER KWH BY IOU AND PAYMENT YEAR

Like the nonresidential sector, utility cost benefits are really driven by storage performance during some specific costly hours. As discussed throughout this report, these systems were generally charging during low marginal cost periods and discharging in the early afternoon and evening during high utility cost and emissions periods, especially during summer months. These higher costs also align with on-peak TOU periods and, as presented below in Figure 6-155, occur throughout the year, but like nonresidential systems, the benefits accrued over a few generation-constrained hours in September.

FIGURE 6-155: RESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY MONTH AND IOU



Cross-Year Performance Impact Comparisons (2021 to 2022)

Verdant also compared the utility avoided costs developed for CY 2021 (provided separately in Appendix C) to those in 2022. These comparisons were made for system-level utilization to highlight any potential changes in avoided costs from one year to the next for systems operational throughout both years. Figure 6-156 and Figure 6-157 present those comparisons for the nonresidential and residential sectors, respectively. Any point on the figure above the line separating the light and gray areas (and right of zero) represents a system exhibiting performance that resulted in utility avoided cost benefits in 2022 greater than 2021 (and vice versa).

FIGURE 6-156: NONRESIDENTIAL CROSS-YEAR UTILITY MARGINAL COST COMPARISON (2021 TO 2022)

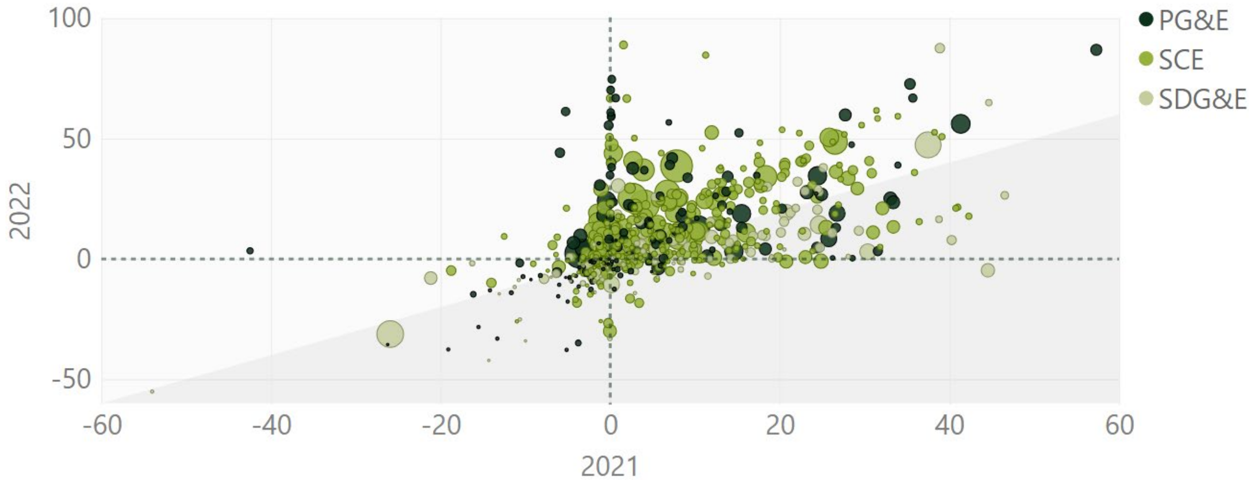
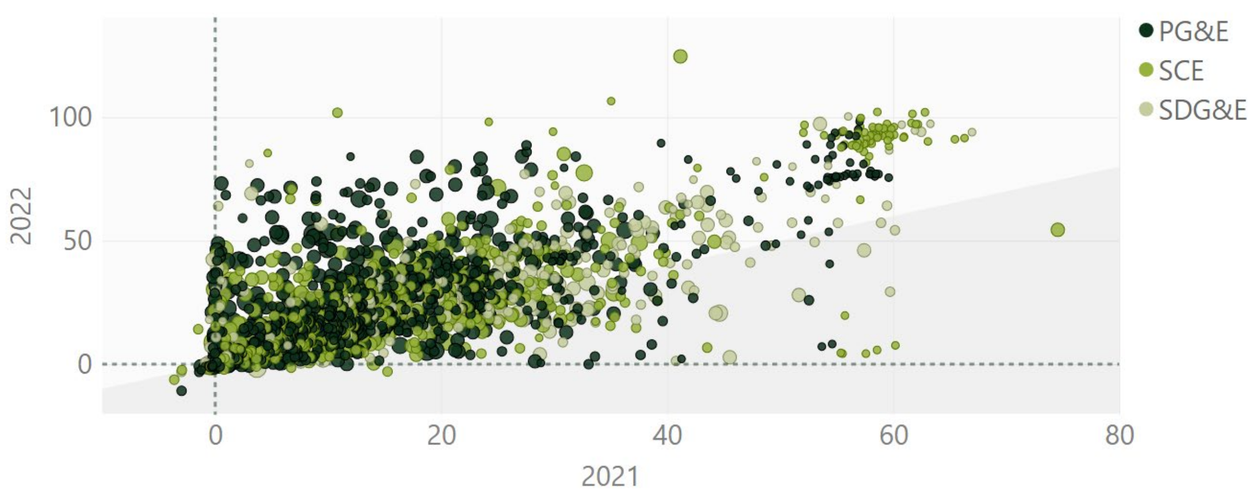


FIGURE 6-157: RESIDENTIAL CROSS-YEAR UTILITY MARGINAL COST COMPARISON (2021 TO 2022)



Utility Avoided Cost Summaries

Below we summarize the total avoided cost benefits (+), or cost incurred (-) throughout 2022 for each of the three IOUs and two customer sectors – nonresidential and residential. Average impacts by avoided cost component are also detailed along with the total. The utilization, timing and efficiency of storage charge and discharge during 2022 provided an avoided cost benefit to all three IOUs. Residential projects provided a greater benefit than nonresidential systems, on average, as a percentage of capacity kWh. We also observe some differences within each sector and across utility as well. Again, the avoided costs are driven much more substantially during a few capacity constrained hours, while other components of the avoided costs are more evenly distributed throughout the year.

FIGURE 6-158: SUMMARY OF 2022 NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS IMPACTS($/KWH)

IOU	n Prj	Avg kW	Avg kWh	Anc Srvcs	Energy	GHG	Generation	T&D	Total
PG&E	254	253	623	$0	$2	$0	$15	$3	$20
SCE	465	307	679	$0	$2	$0	$14	$1	$16
SDG&E	145	242	550	$0	$1	$0	$7	$4	$12
Overall	**864**	**280**	**641**	**$0**	**$2**	**$0**	**$13**	**$2**	**$17**

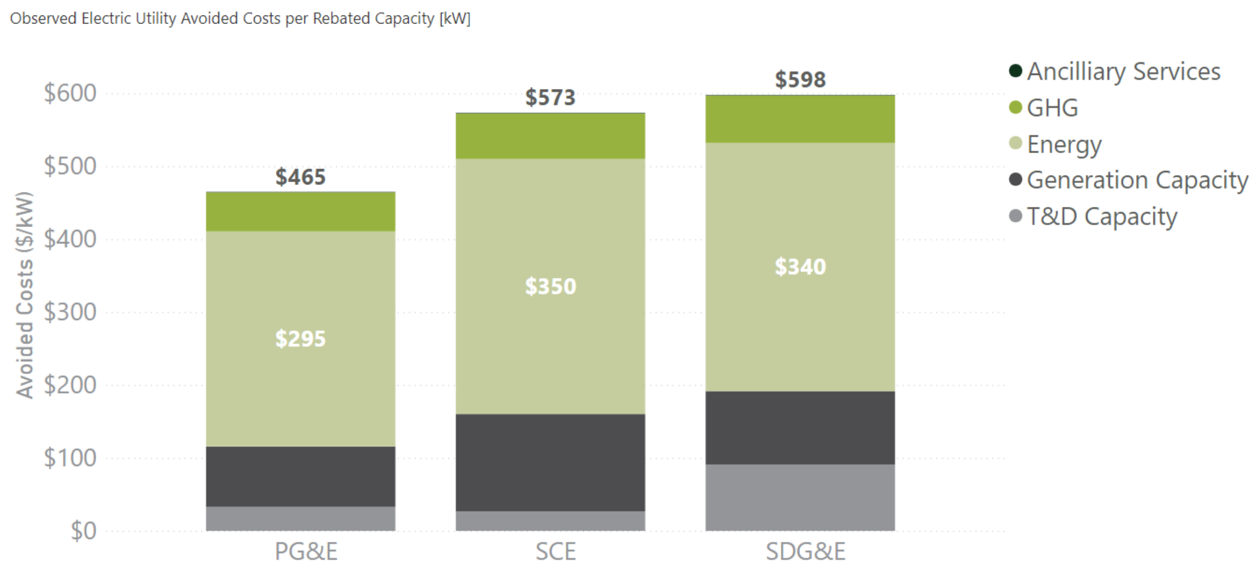
FIGURE 6-159: SUMMARY OF 2022 RESIDENTIAL STORAGE UTILITY AVOIDED COSTS IMPACTS ($/KWH)

IOU	n Prj	Avg kW	Avg kWh	Anc Srvcs	Energy	GHG	Generation	T&D	Total
PG&E	1591	8	21	$0	$3	$0	$16	$3	$24
SCE	821	7	19	$0	$6	$1	$18	$1	$27
SDG&E	396	8	21	$0	$6	$1	$15	$10	$32
Overall	**2808**	**8**	**20**	**$0**	**$4**	**$1**	**$17**	**$4**	**$26**

6.5.2 Generation

Marginal utility cost rates ($/kWh) described previously were combined with observed hourly electricity generation profiles in calculations of avoided costs for generation systems. Results are shown below in Figure 6-160 by IOU, on an avoided cost per incentivized kW basis. SDG&E realized the highest avoided costs per incentivized kW, achieving almost $600 per incentivized kW. PG&E saw avoided costs of $465 per incentivized kW, and SCE saw $573 per incentivized kW in 2022. SDG&E T&D capacity costs were higher than average, while SCE Generation Capacity costs were higher than average. These costs are from the 2022 Avoided Cost Calculator. Avoided costs are higher for generation technologies than for storage projects in part because these are electric utility avoided costs only; for generation projects a complete benefit-cost analysis would be required to account for changes in gas utility costs. Higher capacity factors of generation projects also contribute to differences in avoided costs per unit of capacity.

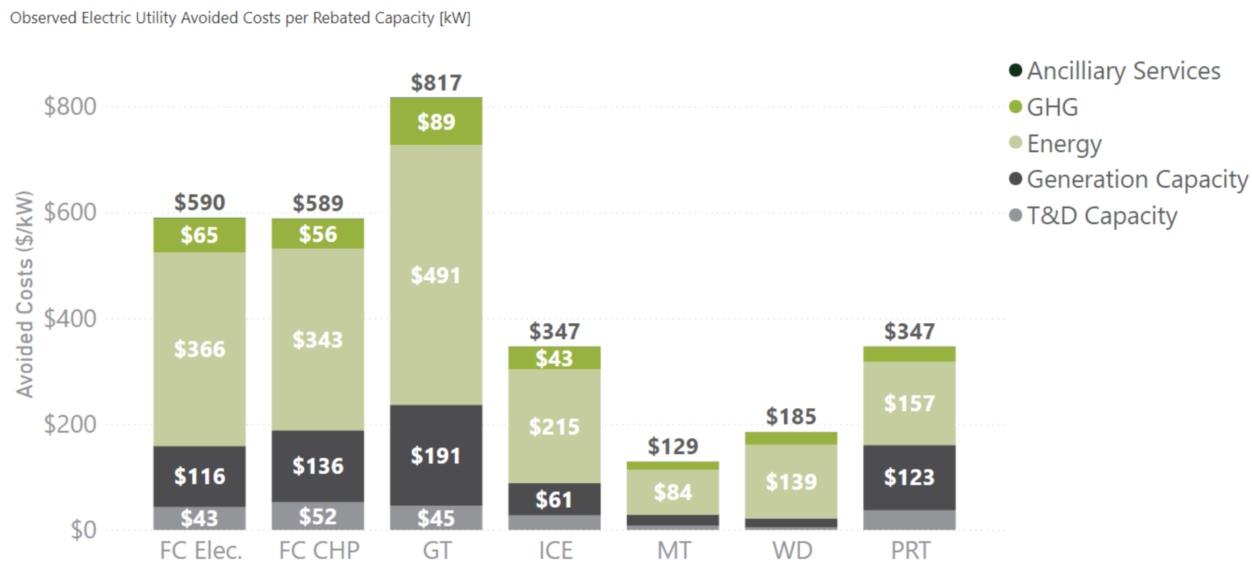
FIGURE 6-160: OBSERVED GENERATION SYSTEM 2022 UTILITY AVOIDED COSTS BY IOU ($ PER REBATED KW)



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

When reviewing the observed utility marginal avoided costs by technology type, as shown below in Figure 6-161, the Gas Turbines avoid the highest total marginal avoided costs per capacity, at over $800/kW, while Microturbines were observed to avoid the fewest marginal costs. Differences in utilization are the most important factor explaining differences in these avoided costs. The distribution of projects across electric utility service areas is another factor. Lastly, avoided electric utility costs are reported only for PG&E, SCE, and SDG&E. Avoided electric utility costs are not reported for projects installed by SGIP participants receiving electric service from some other provider (e.g., LADWP). Consequently, different groups of projects may contribute to calculation of avoided cost results and observed capacity factors. This was the case for microturbines. While the weighted average 2022 capacity factor for microturbines presented in Figure 6-32 was relatively high (76%), the 2022 utility avoided costs were relatively low due to the projects included in the avoided cost analysis having a lower average capacity factor.

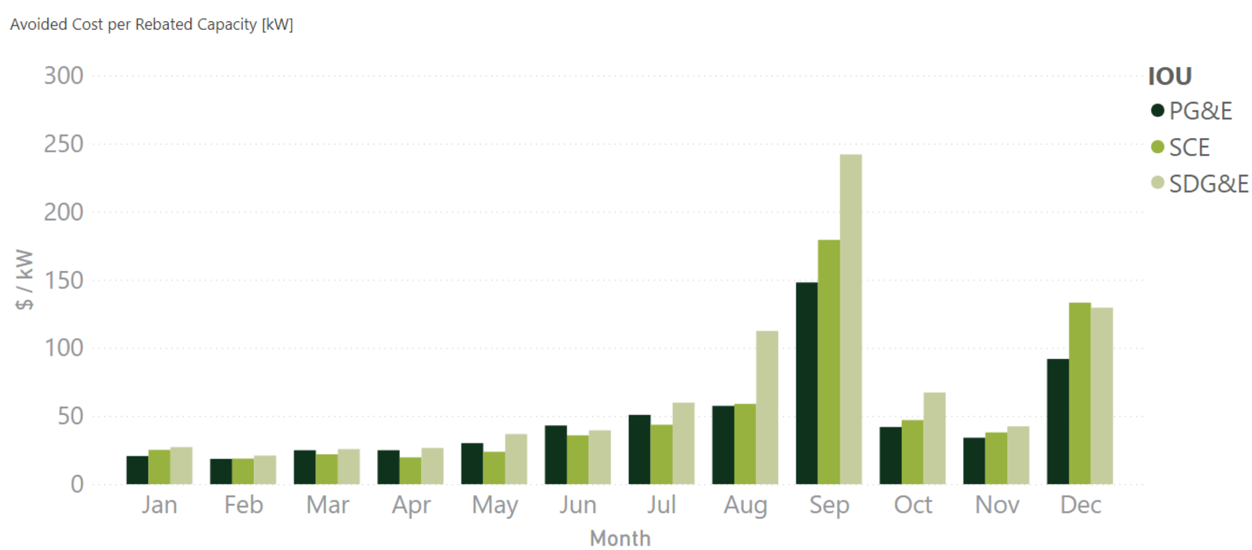
FIGURE 6-161: OBSERVED GENERATION SYSTEM 2022 UTILITY AVOIDED COSTS BY TECHNOLOGY TYPE ($ PER REBATED KW)



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

Figure 6-162 shows the avoided cost rate, per incentivized capacity, by month during 2022. September saw some of the highest avoided cost rates, especially for SCE and SDG&E, topping over $150 per incentivized kW, while the rest of the year the rates were mostly under $40/kW. December also saw some higher values, approaching and exceeding $100/kW by IOU.

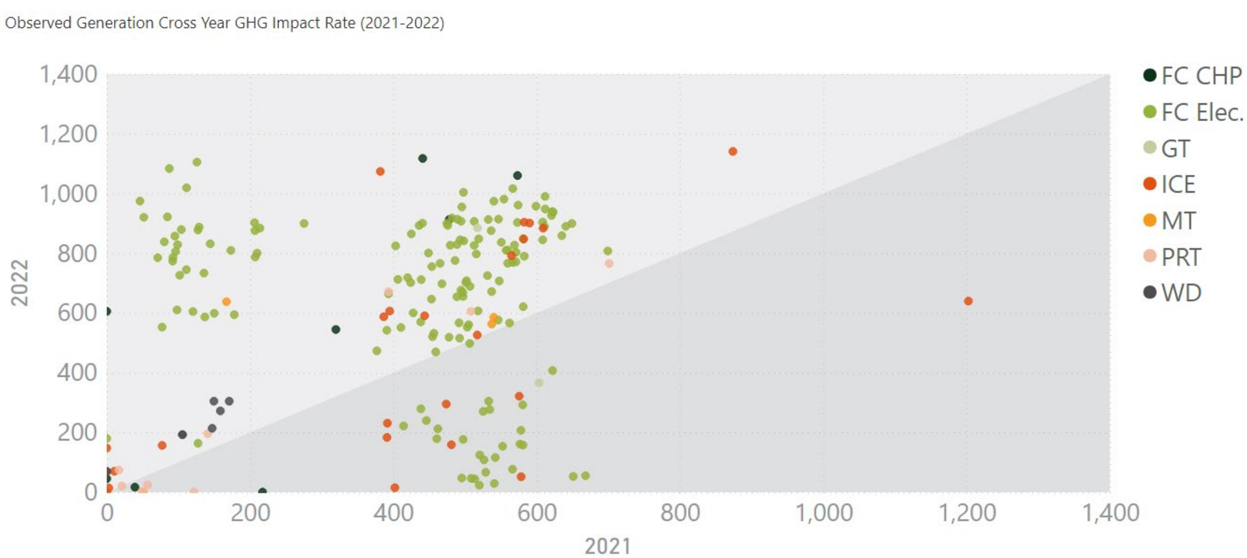
FIGURE 6-162: OBSERVED GENERATION SYSTEM 2022 UTILITY AVOIDED BY IOU AND MONTH



Cross-Year Performance Impact Comparisons (2021 to 2022)

Verdant also compared the utility avoided costs developed for CY 2021 (provided separately in Appendix C) to those in 2022. These comparisons were made to highlight any potential changes in avoided costs from one year to the next. Any point on the figure above the line separating the light and gray areas (and right of zero) represents a system exhibiting performance that resulted in utility avoided cost benefits in 2022 greater than 2021 (and vice versa). For a majority of projects, the utility avoided costs for 2022 were higher than they were for 2021. This was despite a trend toward lower capacity factors in 2022 (Figure 6-39). The trend toward higher avoided costs in 2022 is due to differences in marginal utility costs. During 2022 there were several periods when marginal costs were very high.

FIGURE 6-163: OBSERVED GENERATION CROSS-YEAR UTILITY MARGINAL COST COMPARISON (2021 TO 2022)



Utility Avoided Cost Summaries

Below we summarize the total avoided cost benefits throughout 2022 for each of the three IOU, by equipment type, and by fuel type. All generation systems were found to produce avoided cost benefits. Average impacts by avoided cost component are also detailed along with the total. Gas Turbines showed the greatest avoided costs, driven by the generation and energy components, which also drove the SDG&E and SCE avoided costs higher. Non-renewably fueled systems also saw higher avoided costs than renewable systems, at least in 2022 due to the large amount of generation from these systems.

FIGURE 6-164: SUMMARY OF 2022 GENERATION UTILITY AVOIDED COSTS IMPACTS ($/KW)

Utility	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
PG&E	92	$1	$295	$53	$83	$33	$465
SCE	85	$1	$350	$62	$134	$27	$573
SDG&E	29	$1	$340	$65	$101	$91	$598
Overall	**206**	**$1**	**$329**	**$59**	**$112**	**$36**	**$536**

FIGURE 6-165: SUMMARY OF 2022 GENERATION 2022 UTILITY AVOIDED COSTS IMPACTS BY TECHNOLOGY TYPE ($/KW)

Equipment Type	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
FC CHP	8	$1	$343	$56	$136	$52	$589
FC Elec.	151	$1	$366	$65	$116	$43	$590
GT	2	$1	$491	$89	$191	$45	$817
ICE	25	$0	$215	$43	$61	$27	$347
MT	4	$0	$84	$16	$21	$8	$129
PRT	9	$0	$157	$29	$123	$37	$347
WD	7	$0	$139	$24	$17	$4	$185
Overall	**206**	**$1**	**$329**	**$59**	**$112**	**$36**	**$536**

FIGURE 6-166: SUMMARY OF 2022 GENERATION UTILITY AVOIDED COSTS BY FUEL TYPE ($/KW)

Fuel Type	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
Non-Renewable	165	$1	$386	$70	$135	$42	$634
Other	16	$0	$142	$25	$35	$10	$213
Renewable	25	$1	$259	$48	$84	$32	$424
Overall	**206**	**$1**	**$329**	**$59**	**$112**	**$36**	**$536**

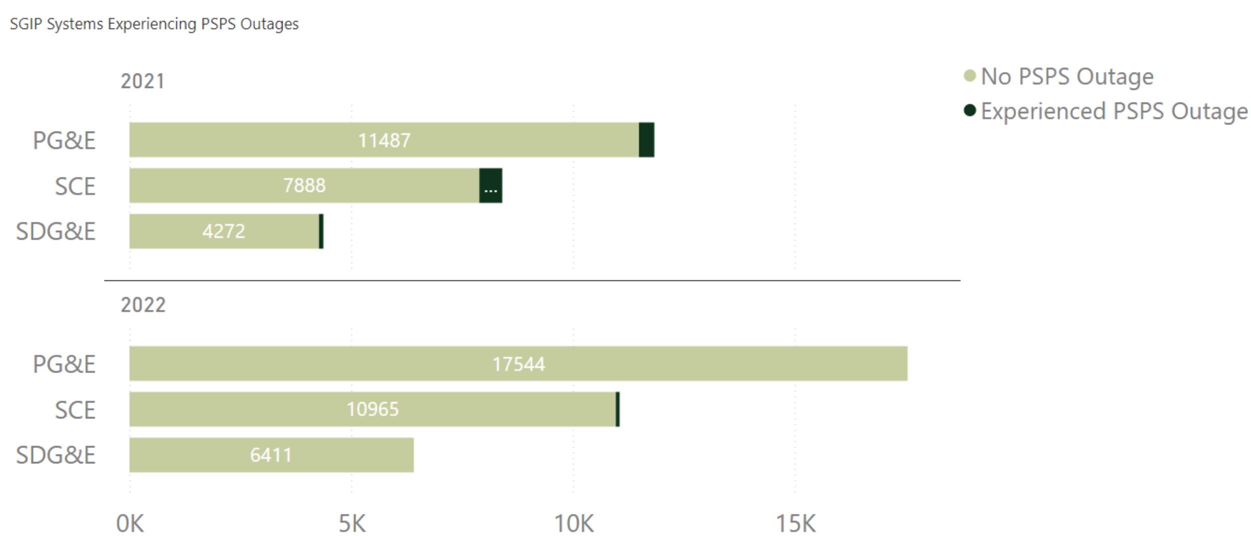
6.6 ENERGY STORAGE IMPACTS DURING PSPS EVENTS

Wildfire risk poses a challenge in California, especially during the long duration periods of high temperature, low humidity and gusting winds in the late summer and fall. These severe weather events can threaten portions of the electricity transmission and distribution system and, more importantly, vulnerable communities and populations. In 2018, the CPUC, working alongside CAL FIRE and other public safety officials, developed a High Fire-Threat map which identified areas that are at extreme risk or elevated risk for wildfires. Furthermore, the CPUC built upon earlier rules providing authority to electric utility companies to shut down portions of the electric grid in response to wildfire threat.

In September through December of 2020 these threats were realized, leaving hundreds of thousands of electric customers without power – sometimes for days. The 2020 SGIP Energy Storage Impact Evaluation examined how SGIP residential customers experiencing Public Safety Power Shutoffs (PSPS) utilized their storage systems to provide resiliency during outages stemming from wildfire threat in 2020. Systems paired with on-site solar were capable of riding out longer duration utility power shutoffs – sometimes for 3 days – because the system could charge directly from solar, and the solar energy could be used to partially power the home during the day.

Fortunately, the number of PSPS outages – and their frequency and duration – throughout the state were greatly reduced in 2021 compared to 2020. Even better, PSPS outages in 2022 were even less than in 2021. Figure 6-167 details the total number of SGIP projects installed and operable in 2021 and 2022 by IOU along with the distribution affected by PSPS outages. PG&E had 307 (3%) of their total 11,794 storage projects experience a PSPS event in 2021. None of their total 17,544 storage projects experienced a PSPS outage in 2022. SCE had 482 projects (6%) of their total 8,370 projects experiencing a PSPS event in 2021 and 77 (1%) of their total 11,042 projects experienced a PSPS event in 2022. SDG&E observed 90 (2%) of their 4,362 projects experienced PSPS outages in 2021. None of their total 6,411 storage projects experienced a PSPS outage in 2022.

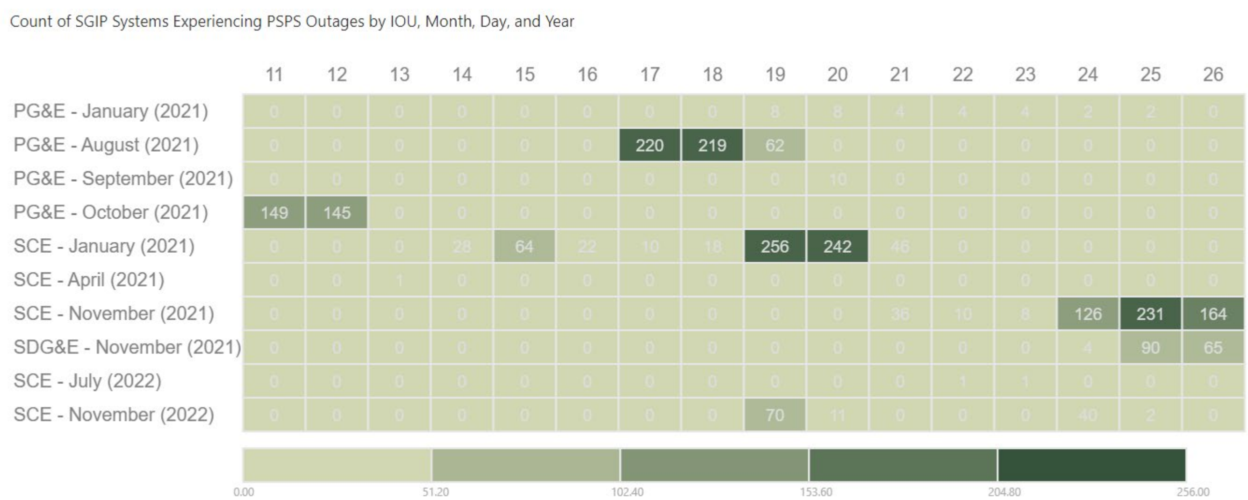
FIGURE 6-167: PERCENTAGE OF SYSTEMS AFFECTED BY PSPS OUTAGES IN 2021 AND 2022 BY IOU



While PSPS outages were limited in 2021 and 2022, Verdant still reviewed the metered storage, PV, and load data for each sampled project to garner more information about the resiliency afforded by SGIP incentivized storage to customers experiencing grid de-energization. We first reviewed the frequency and timing of events, which are presented in the heatmap below (Figure 6-168). The data Verdant received from each of the three IOUs provided PSPS outage information affecting a significant number of customers (over 50) during the following time periods:

- 2021
  - PG&E: August 17th – 19th and October 11th – 12th
  - SCE: January 15th, January 19th – 20th, and November 24th - 26th
  - SDG&E: November 25th - 26th
- 2022
  - SCE: November 19th-20th

FIGURE 6-168: PSPS EVENT DAYS BY IOU



The above information represents population summaries from the program for each calendar year evaluated for this study. Verdant developed a stratified random sample to estimate program-level impacts, so the total number of projects we sampled and received data for are less than the population totals. Overall, our analysis includes 10% of the total of 879 sites experiencing PSPS events in 2021 and 12% of the total of 77 sites experiencing PSPS events in 2022. The 2021 sample of PG&E sites analyzed below includes 40 residential sites, SCE includes 33 residential and 1 nonresidential project, and SDG&E has 9 residential and 1 nonresidential. The 2022 sample of SCE includes 8 residential and 1 nonresidential project in 2022. SGIP customers in PG&E territory experienced the longest PSPS outages in 2021, with the average length of outage being 29 hours (over 1 day), and the longest event lasting 158 hours (almost 6.6 days). SCE experienced their longest event lasting 78 hours (over 3 days), with the average event lasting 27 hours (over 1 day). SDG&E's average event lasted 12 hours with their longest event lasting 41 hours (less than 2 days).

Figure 6-169 below displays the average hourly net discharge, consumption, load, and PV generation as a percentage of system kWh capacity for PG&E SGIP customers who experienced a PSPS outage in October 2021. The figure compares PSPS outage performance on the left to non-PSPS performance throughout weekdays of the same season. Each stream is discussed in more detail below.

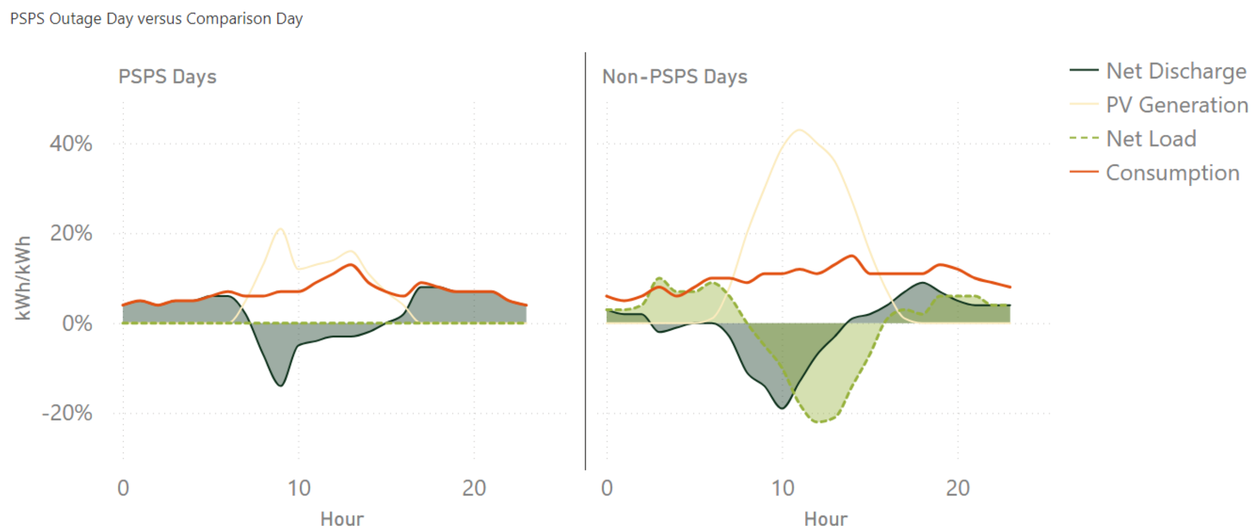
Net Discharge. This represents the hourly charge (-) or discharge (+) utilization of the energy storage system during outages (left) and throughout similar days with full grid connectivity (right). On non-PSPS days, storage systems are performing normal operations – charging from on-site solar and discharging during the on-peak period and after to reduce delivered load from the utility. During PSPS days, storage discharge and solar generation are the only means by which a customer can still service plug loads and critical circuits, so storage discharges a much greater magnitude of energy, particularly during non-PV generating hours in the evening and overnight.

PV Generation. Differences in solar generation are more pronounced across days, with typical solar generation evident on the right, and significantly reduced output observed on outage days. Peak and overall solar PV generation throughout the PSPS events and while islanding is scaled back as solar output is curtailed. Excess PV generation cannot be exported to the grid throughout an outage, so systems are likely configured to curtail solar output to balance supply and demand behind the meter – either energy storage charging or backed up critical circuits.

Net Load. The obvious difference in delivered and received utility load on PSPS event days is the complete absence of it. Metered load during the outage is zero, whereas normal load shapes of excess PV export and import when storage is not discharging are evident on the right.

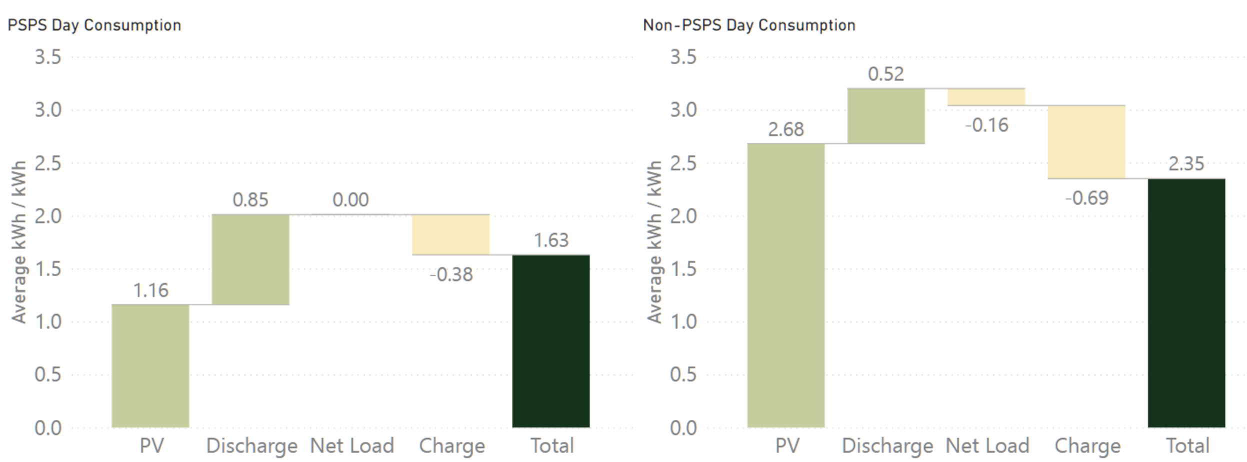
Consumption. Consumption represents the BTM metered customer load and includes – in the case of PSPS days – all circuits backed up and providing resiliency throughout the outage. The main takeaway here is that even though customers are disconnected from the grid during outages, a combination of solar generation and energy storage utilization provides customers with personal resiliency.

FIGURE 6-169: AVERAGE HOURLY LOAD SHAPES DURING PSPS EVENTS VS. NON-PSPS EVENTS



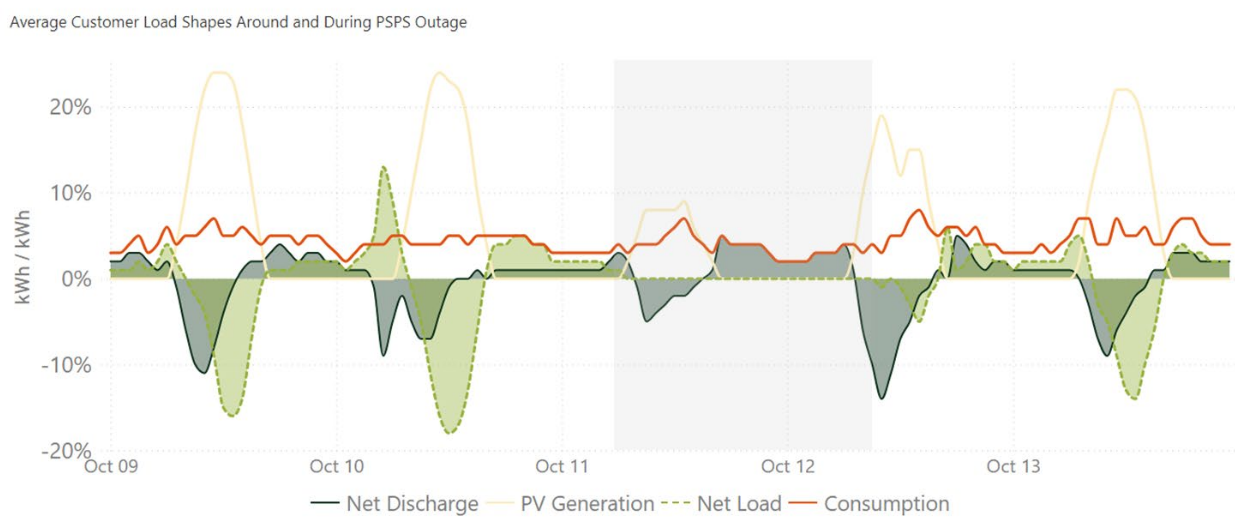
The load shapes above have been summed below to the daily level to better compare overall differences between the streams. Green bars represent PV generation or energy storage discharge, and charge is represented by the yellow bar. In this example, net load is zero on PSPS outage days, and slightly negative (and yellow) on non-outage days because customers are exporting more to the grid than they are receiving from the utility. Overall BTM consumption is represented by the dark bar. We observe greater storage discharge utilization on event days as more of the capacity is used for customer resiliency and greater PV generation on non-outage days as curtailment is not limiting solar output. While customers are consuming more on non-event days, non-zero consumption on outage days highlight the benefits afforded from a paired solar plus storage system to utility customers.

FIGURE 6-170: AVERAGE HOURLY LOAD SHAPES DURING PSPS EVENTS VS. NON-PSPS EVENTS



Finally, Figure 6-171 provides a time series of normal SGIP system performance punctuated by a planned PSPS outage. System performance and load shapes after the outage are also presented. The outage itself is highlighted from roughly 7 am on October 11th through 9 am on October 12th. This five-day example reveals much of the same information as prior exhibits regarding storage system utilization, PV generation, customer load, and BTM consumption. One additional point is the more significant storage charging on the morning of October 10th, just a day before the outage. Also, that evening the battery doesn't conduct arbitrage and is not self-consuming. It's likely the customer (and/or the energy storage system) received an impending outage alert from IOU or the equipment's storm watch, so the battery discharge was withheld so sufficient SOC was available if the grid lost power. After customers are re-connected, the storage system conducts a deep charge on the morning of October 12th to increase the battery SOC, and typical performance resumes thereafter.

FIGURE 6-171: NET DISCHARGE, LOAD, PV, AND CONSUMPTION OVER 5-DAY PERIOD WITH A PSPS OUTAGE



6.7 RESIDENTIAL STORAGE OPTIMIZATION

Previous sections have revealed how the performance and utilization of residential energy storage systems contributed to decreases in greenhouse gas (GHG) emissions and utility costs, while providing bill savings to host customers in 2022. Residential energy storage systems are generally conducting 1) TOU arbitrage without export, 2) TOU arbitrage with export – either regularly or exclusively throughout specific times like a demand response event, 3) self-consumption, or 4) some combination of all. We observe residential PV paired systems discharging, on average, 45% of system capacity daily and many residential customers are limiting discharge to maintain net zero load rather than exporting. This finding is intuitive – if customers are already abiding by SGIP rules for round-trip efficiency, utilization and GHG reductions

– they may also want to have reserve energy in the event of an outage. Furthermore, frequent full discharge cycling may not be advantageous from a battery engineering, effective useful life, and warranty perspective.

Storage project developers and host customers may not be aware of system-level peak hours, energy prices, or marginal emissions unless they are enrolled in a demand response program or real-time pricing rate where a price signal (or incentive) encourages shifting or reducing demand. Customers understand their BTM consumption and bill rate structure, but grid-level demand may not be in their purview. The 4-9pm on-peak TOU hours provide a broad signal to arbitrage energy over a five-hour period, but emissions vary considerably during this period, narrowing the window for achievement of maximum emissions reductions. A perfectly designed energy storage system optimized to reduce GHG emissions or respond to grid emergencies would charge only during the lowest marginal emissions or utility cost periods and discharge only when marginal emissions or utility costs are at their maximum. The motivation behind this optimization analysis is to quantify the considerable untapped potential of battery capacity if deployed in response to grid needs.

Verdant has developed a simulation tool that can dispatch storage systems for optimal timing and magnitude in response to specified signals and other conditions. This tool can estimate benefits of optimized dispatch based on selected objectives, including 1) to minimize the customer's bill, 2) to minimize greenhouse gas emissions, or 3) to minimize utility costs. In this section we explore how the observed real-world performance of residential SGIP storage systems compares to simulated optimal performance for these dispatch scenarios.

Data and Methods

Verdant's optimization tool uses mixed-integer linear programming to optimally dispatch storage under assumed battery, load, and PV conditions.

Battery configuration information is required for the model, including the system's total energy capacity (kWh) and its charge/discharge power capacity (kW). This information is collected from the statewide project list. The model also requires input that specifies the round-trip-efficiency (RTE) of the battery as well as the minimum state of charge (SOC) allowable for the battery. For these optimized dispatch runs we simulated systems with RTEs of 90%, which is at the high end of measured residential RTEs and is indicative of the energy losses associated with a single duty cycle. Observed residential system efficiencies range considerably based on the equipment type and overall utilization. Under-utilization can result in the accumulation of parasitic losses which can further erode the actual efficiency of the system over time. This helps explain why the average residential fleet level RTE in 2022 was 81% - with maximum RTEs at or just above 90%.

Another important modeling constraint is not to allow the battery to discharge beyond a predetermined minimum SOC. Verdant modeled optimized dispatch to maintain a minimum SOC of 35% of its total capacity. The assumption was based on discussions with some OEMs, and – just like the RTE – can vary based on system operating mode and technology type. The model also requires specification of the battery's SOC at the beginning of the optimization horizon (e.g., January 1 at midnight). We set beginning SOC equal to the battery's minimum allowable SOC.

The model requires information on the customer's hourly interval gross consumption and PV data (if present). The customer's gross consumption was calculated from the IOU provided AMI data or developer metered load and the metered storage charge and discharge data collected for this evaluation. The customer's gross consumption (i.e., their consumption if they didn't have a battery installed) was calculated as their net load with the battery charge and discharge activity backed out. For customers with PV onsite, the hourly metered interval PV generation data provided by project developers and manufacturers was also backed out of the AMI data to determine the customer's gross consumption. Both the gross consumption and the PV generation interval data are used as inputs in the optimization model. The simulations were performed on systems with a full year of gross load and dispatch data in 2022.

The final input required for the optimization is information related to the model's objective, (i.e., the cost against which the model is minimizing). We simulated optimal dispatch against three different representations of cost; They are 1) the customer's bill, 2) greenhouse gas emissions (GHG), and 3) utility costs (UC). For simulations minimizing the customer's bill, we reviewed the historical rate selection of each customer (provided by the IOUs) and noted their selected rate on or near June 2022. The import and export costs (under NEM 2.0)[46] associated with the customer's tariff were then included in the model. Simulations that minimized greenhouse gas emissions utilized the WattTime SGIP signal marginal emissions rate for the customer's associated grid region. To minimize utility costs, we used hourly utility avoided cost values for the customer's associated utility and climate zone.

A mixed-integer linear program was used for our simulations. The simulations assume "perfect knowledge", meaning that decisions are made about the optimal dispatch over the entire optimization horizon with full knowledge of the actual load and PV generation over the entire horizon. In reality, PV and customer load can be forecasted ahead of time, and the GHG signal is forecasted by WattTime for the next 72 hours, but none of these are known exactly on a day-ahead basis. For this reason, we modeled

[46] Some customers were likely on NEM 1.0, which has identical rates for customer import and export, whereas under NEM 2.0 the export rate is slightly less during any TOU period. Thus, NEM 1.0 customers have no economic incentive to minimize exports, while NEM 2.0 customers have a small incentive to do so. The difference between customer bills is likely small.

each day individually to replicate real-world conditions more closely. For customer bill scenarios where customers were on a tiered rate, the scenarios were modeled at the monthly level.

In our simulations, we limited the battery so that it could only charge from energy generated by the on-site PV. In cases with no PV on-site the battery was allowed to charge directly from the grid, however exports were not allowed.

Results

Throughout this section, we will present comparisons of optimal and actual observed battery dispatch. Note that the observed dispatch results presented here will differ from the avoided utility costs, avoided GHG emissions, and customer bill savings presented in previous sections of this report. The results shown here are exclusive to projects included in our optimization modeling. Projects were dropped from the optimization modeling sample for several reasons, including lack of information on the customer's rate along with quality control of the simulation results. The results presented in this section are meant to be used for directional purposes and are not intended to be taken as a final reporting of avoided utility costs, reduced GHG emissions, or customer bill savings.

The following figures (Figure 6-172, Figure 6-173, and Figure 6-174) below show the average avoided utility costs, reduced GHG emissions, and customer bill savings of the three optimal scenario types (Optimal Avoided Utility Cost, Optimal GHG, and Optimal Bills) compared with actual dispatch. The bars on each chart represent the three optimal scenarios or actual dispatch.

Figure 6-172 below shows that optimizing dispatch for utility costs has the potential to reduce utility costs by four times the reductions achieved by the actual dispatch ($108 versus $26, per kWh of battery capacity). Interestingly, we also find that optimizing for GHG reduction and customer bill savings could reduce utility costs further than actual dispatch (with increased reductions of 85% and 54%, respectively).

FIGURE 6-172: 2022 AVOIDED UTILITY COSTS FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS ($ PER KWH)

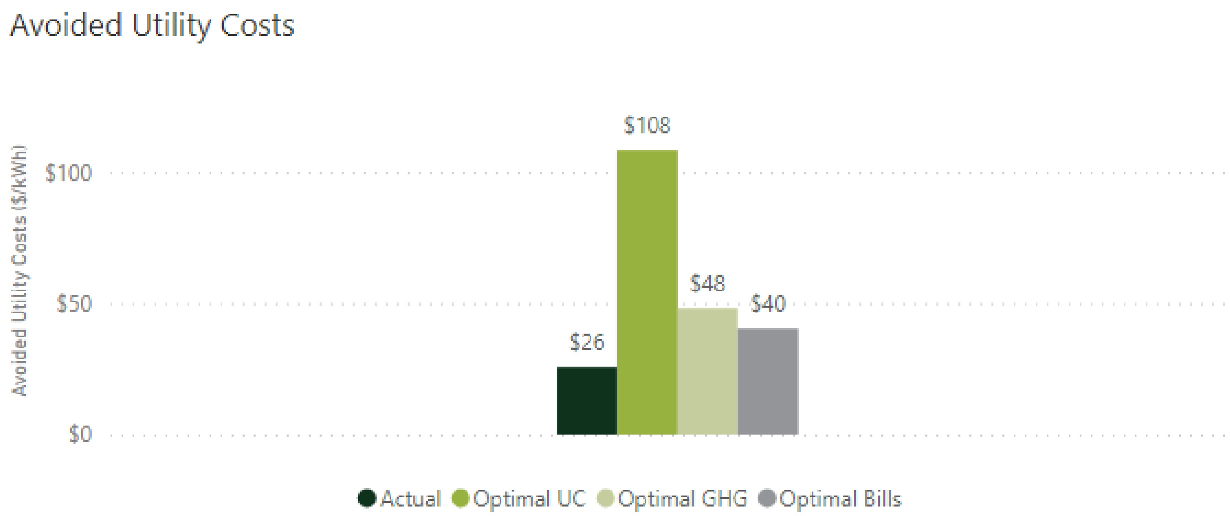


Figure 6-173 below shows that optimizing for GHG emissions has the potential to reduce GHG emissions by 56 kg per kWh of capacity (more than 3 times the reduction achieved by actual dispatch). Notably, optimizing for utility costs achieves nearly the same amount of GHG reduction as the optimal GHG scenario (54 kg per kWh of capacity). The scenario which optimizes customer bills also achieves higher GHG emission reductions than actual dispatch (29 kg/kWh and 17 kg/kWh, respectively).

FIGURE 6-173: 2022 EMISSIONS REDUCTION FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS (KG CO2 PER KWH)

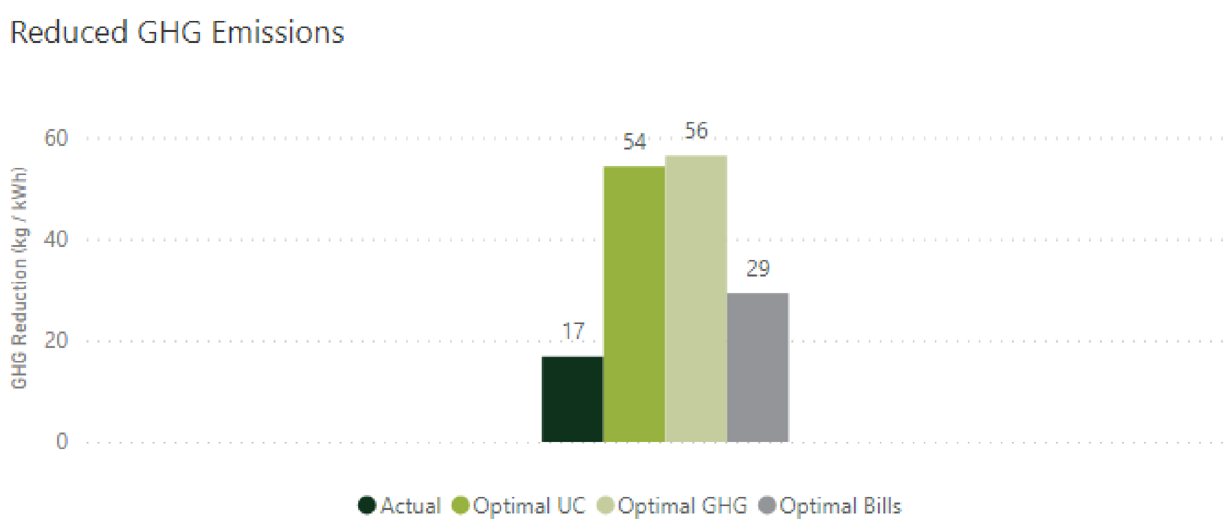


Figure 6-174 below shows that optimizing for customer bill savings has the potential to reduce customer bills by $21 per kWh of capacity (50% higher savings than the actual dispatch). Both the optimal utility avoided cost and optimal GHG scenarios deliver nearly identical average customer bill savings to the actual dispatch.

FIGURE 6-174: 2022 CUSTOMER BILL SAVINGS FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS ($ PER KWH)

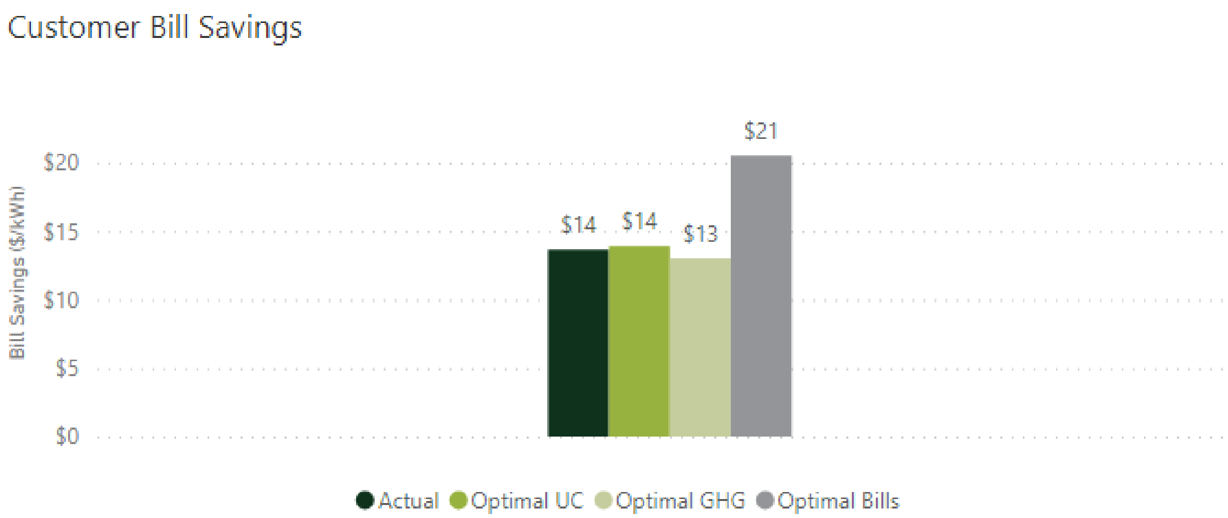


Figure 6-175 following presents a heatmap of the average hourly charge and discharge pattern for each hour of the day by month. The figure shows battery dispatch activity for the actual dispatch, followed by the dispatch activity for the optimal utility avoided cost scenario, the optimal GHG scenario, and finally the optimal customer bill scenario. These figures highlight that each optimal scenario charges and discharges more completely than the actual dispatch during charging and discharging hours. In addition, the charging profiles are virtually identical between utility cost and GHG-optimized scenarios, while discharge patterns are very similar between those two scenarios.

The actual dispatch never charges more than 10% of capacity in any given month-hour, while the optimal scenarios charge up to 15% of capacity in a single month-hour. Similarly, the actual dispatch never discharges more than 6% of capacity in any given month-hour, while the optimal scenarios discharge 22% to 34% of capacity in their peak discharge month-hours.

When comparing the hours of the day that the battery typically discharges, the optimal customer bill scenario is most like actual, with most of the discharge activity occurring between 4pm and 9pm. Both the optimal customer bill scenario and the actual dispatch also maintain relatively uniform hourly dispatch patterns throughout the year. In contrast, the optimal UC and optimal GHG scenarios vary their discharge patterns significantly from month to month (following the heterogenous nature of the UC and GHG cost signals). Their dispatch patterns are like each other, with the highest discharge hours occurring May through August primarily during the 7-8pm hour.

FIGURE 6-175: AVERAGE HOURLY DISPATCH BY MONTH FOR ACTUAL AND OPTIMAL UTILITY COSTS, OPTIMAL GHG, AND OPTIMAL CUSTOMER BILLS

Actual Hourly Discharge (+) Charge (-) kWh / kWh Capacity

month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-4%	-2%	0%	3%	4%	4%	[illegible]	3%	2%	1%	1%
2	1%	1%	1%	0%	0%	0%	1%	-0%	-3%	-7%	-8%	-8%	-5%	-3%	-1%	0%	3%	5%	5%	4%	4%	2%	2%	1%
3	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-7%	-9%	-9%	-6%	-4%	-2%	0%	2%	4%	5%	5%	4%	3%	2%	2%
4	1%	1%	1%	1%	1%	1%	1%	-0%	-4%	-7%	-9%	-8%	-6%	-3%	-1%	0%	2%	3%	4%	5%	4%	[illegible]	3%	2%
5	1%	1%	1%	1%	1%	1%	1%	-1%	-5%	-8%	-10%	-8%	-5%	-3%	-1%	0%	3%	4%	4%	5%	5%	3%	3%	2%
6	1%	1%	1%	1%	1%	1%	0%	-2%	-5%	-9%	-10%	-8%	-6%	-3%	-1%	1%	4%	5%	6%	5%	5%	[illegible]	3%	2%
7	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-8%	-10%	-9%	-6%	-4%	-2%	0%	4%	5%	6%	5%	5%	[illegible]	2%	2%
8	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-7%	-10%	-10%	-7%	-4%	-2%	0%	5%	6%	6%	6%	5%	3%	2%	2%
9	1%	0%	0%	1%	1%	1%	1%	-0%	-3%	-6%	-9%	-9%	-7%	-4%	-2%	0%	4%	6%	6%	5%	4%	2%	2%	1%
10	1%	0%	0%	1%	1%	1%	1%	0%	-2%	-5%	-8%	-9%	-7%	-5%	-2%	0%	[illegible]	5%	6%	5%	4%	2%	2%	1%
11	0%	0%	0%	0%	0%	0%	0%	-1%	-3%	-6%	-7%	-7%	-5%	-3%	-1%	1%	4%	5%	5%	4%	[illegible]	2%	1%	1%
12	-1%	-0%	-0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-3%	-1%	1%	4%	5%	4%	[illegible]	2%	1%	1%	0%

Minimize Utility Costs

month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-3%	[illegible]	-9%	-10%	-10%	-5%	-3%	3%	10%	11%	5%	7%	5%	2%	0%
2	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-2%	-5%	-5%	-9%	-12%	-13%	-11%	-7%	1%	10%	9%	5%	10%	13%	7%	0%
3	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-2%	-2%	-5%	-9%	-10%	-13%	-10%	-7%	-5%	4%	7%	8%	5%	14%	14%	4%
4	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-4%	-8%	-10%	-8%	-8%	-11%	-9%	-5%	-2%	5%	13%	9%	7%	17%	7%
5	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-4%	-7%	-12%	-13%	-10%	-5%	-5%	-1%	-7%	-3%	-0%	23%	23%	8%	4%	2%
6	-0%	-0%	-0%	-0%	-0%	0%	-0%	-2%	-6%	-12%	-15%	-14%	-5%	1%	-5%	2%	1%	-1%	10%	21%	11%	4%	1%	2%
7	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-5%	-11%	-15%	-12%	-10%	-5%	-3%	4%	-2%	3%	9%	17%	6%	5%	7%	5%
8	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-5%	-10%	-14%	-14%	-9%	-7%	-2%	0%	-4%	0%	19%	34%	1%	2%	1%	0%
9	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-3%	-8%	-12%	-14%	-9%	-5%	-5%	-3%	-5%	1%	19%	19%	5%	6%	7%	1%
10	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-2%	-5%	-9%	-14%	-11%	-10%	-7%	-4%	5%	16%	11%	4%	7%	7%	3%	2%
11	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-2%	-4%	-7%	-10%	-11%	-11%	-7%	-1%	3%	5%	10%	7%	9%	10%	5%	0%
12	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-3%	[illegible]	-8%	-9%	-8%	-5%	-1%	3%	6%	4%	4%	14%	7%	1%	-0%

Minimize GHG

month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-3%	-6%	-9%	-11%	-10%	-5%	-3%	4%	[illegible]	9%	3%	7%	5%	3%	-0%
2	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-2%	-5%	-5%	-9%	-12%	-13%	-11%	-7%	1%	12%	8%	1%	9%	16%	8%	1%
3	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-1%	-5%	-9%	-11%	-12%	-9%	-7%	-5%	4%	5%	8%	5%	13%	15%	5%
4	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-4%	-8%	-10%	-8%	-9%	-11%	-9%	-5%	-1%	5%	15%	9%	6%	17%	7%
5	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-4%	-7%	-11%	-13%	-6%	-2%	-5%	-4%	-8%	-3%	1%	19%	20%	[illegible]	4%	2%
6	-0%	-0%	-0%	-0%	-0%	0%	-0%	-2%	-6%	-11%	-15%	-14%	-5%	2%	-5%	-1%	-2%	-1%	4%	22%	18%	3%	2%	2%
7	-0%	-0%	-0%	-0%	-0%	0%	-0%	-1%	-4%	-10%	-14%	-12%	-10%	-5%	-3%	3%	-5%	1%	3%	22%	10%	7%	7%	5%
8	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-5%	-10%	-14%	-14%	-9%	-5%	1%	4%	-2%	-1%	12%	23%	9%	3%	2%	0%
9	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-3%	-7%	-12%	-13%	-9%	-4%	-2%	-1%	-4%	3%	15%	8%	6%	7%	9%	1%
10	-0%	-0%	-0%	-0%	-0%	-0%	0%	0%	-1%	-4%	-9%	-14%	-11%	-10%	-7%	-5%	5%	15%	11%	0%	6%	9%	6%	2%
11	-0%	-0%	-0%	-0%	-0%	-0%	0%	-0%	-2%	-4%	-7%	-10%	-11%	-11%	-8%	-1%	2%	7%	[illegible]	4%	6%	13%	6%	0%
12	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-3%	-6%	-7%	-9%	-8%	-5%	-1%	3%	6%	3%	3%	14%	7%	0%	-0%

Minimize Customer Bills

month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-4%	-9%	-9%	-11%	-9%	-5%	-1%	8%	6%	7%	7%	17%	0%	0%	-0%
2	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-3%	-4%	-13%	-10%	-13%	-11%	-5%	-1%	11%	6%	8%	9%	20%	0%	-0%	-0%
3	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-4%	-12%	-9%	-13%	-12%	-7%	-2%	9%	[illegible]	8%	7%	21%	0%	0%	-0%
4	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-3%	-3%	-13%	-9%	-14%	-12%	-7%	-2%	6%	12%	7%	11%	21%	0%	0%	-0%
5	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-4%	-4%	-13%	-8%	-14%	-12%	-7%	-3%	7%	15%	7%	9%	22%	0%	0%	-0%
6	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-4%	-4%	-14%	-8%	-14%	-11%	-7%	-3%	7%	15%	8%	7%	22%	0%	0%	-0%
7	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-3%	-4%	-13%	-9%	-14%	-12%	-8%	-3%	7%	16%	8%	7%	22%	0%	0%	-0%
8	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-3%	-4%	-13%	-9%	-14%	-12%	-8%	-3%	7%	13%	8%	11%	21%	0%	0%	-0%
9	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-4%	-12%	-9%	-14%	-12%	-8%	-3%	8%	12%	8%	9%	21%	0%	0%	-0%
10	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-3%	-11%	-10%	-14%	-12%	-8%	-3%	8%	13%	8%	8%	21%	0%	0%	-0%
11	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-3%	-5%	-11%	-10%	-12%	-9%	-5%	-1%	9%	6%	[illegible]	6%	19%	0%	0%	-0%
12	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-4%	-9%	-8%	-9%	-7%	-4%	-1%	7%	5%	9%	4%	16%	0%	0%	-0%

The following two figures (Figure 6-176 and Figure 6-177) display the average weekday battery dispatch pattern for the three optimization scenarios, alongside the actual dispatch pattern during the same period. The shaded region highlights the typical peak pricing period of 4-9pm. Figure 6-176 presents the average dispatch in August and Figure 6-177 presents the average dispatch in March. In all cases, the optimal scenarios charge and discharge more completely than the actual dispatch activity. The optimal GHG and optimal UC scenarios discharge more significantly in August compared to March. This is due to higher marginal GHG emissions and higher utility costs in August.

The optimal customer bill discharge pattern is relatively consistent between August and March. The optimal customer bill discharge pattern typically discharges more energy at 8-9pm followed by 4-6pm. This dual-peak discharge pattern is due to the mixed-integer linear program choosing one of many possible optimal discharge patterns. The model chooses to maximally discharge at the end of the peak price period (typically 8-9pm), followed by additional discharge during earlier hours (favoring hours with more rapidly increasing net load). Customer bills could be similarly optimally reduced by a more even discharge across the peak price period (typically 4-9pm or 5-8pm). In a real-world scenario, there may be other considerations beyond cost that would favor a more even discharge across the peak price period, such as unexpected changes in forecasted load which could reduce the economic benefit in certain hours of the peak price period.

FIGURE 6-176: AVERAGE ACTUAL AND OPTIMAL DISPATCH ON WEEKDAYS IN AUGUST 2022

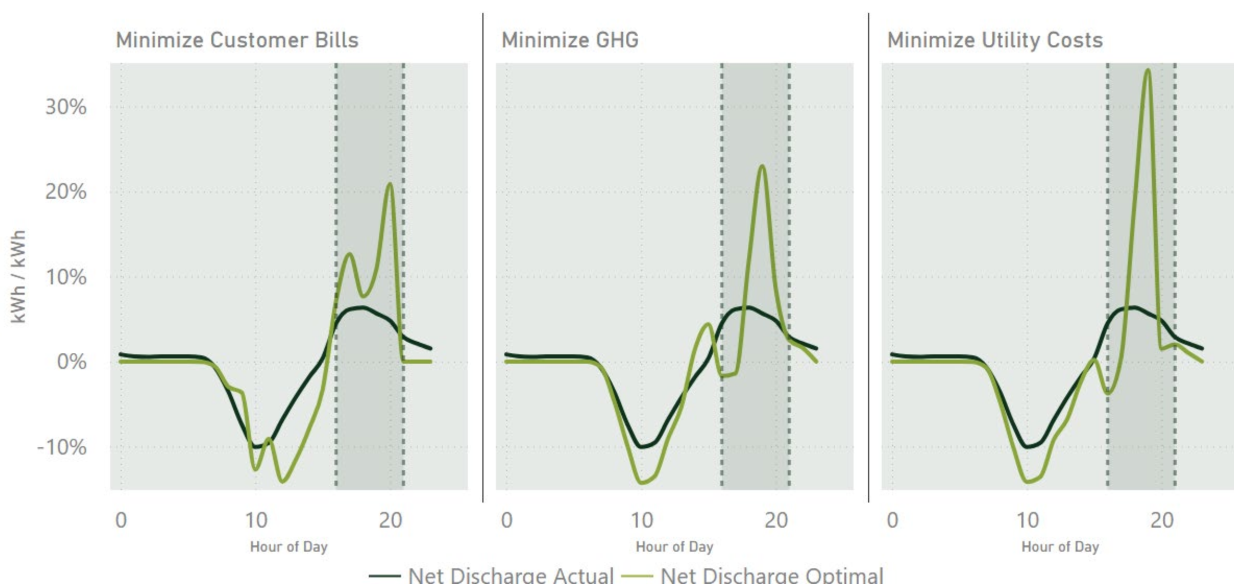


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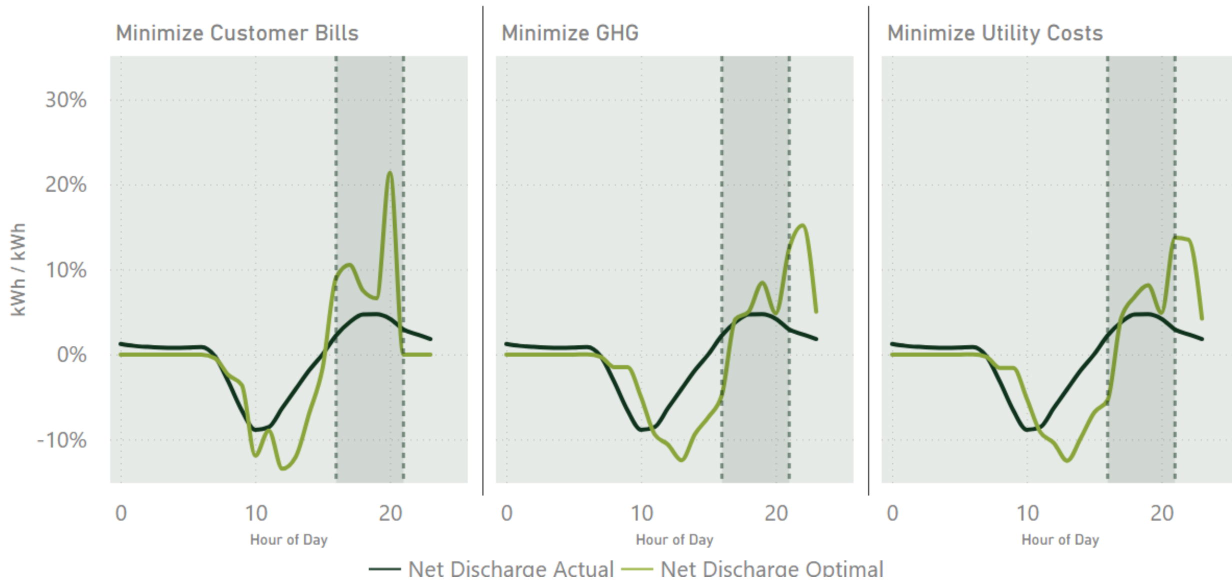
FIGURE 6-177: AVERAGE ACTUAL AND OPTIMAL DISPATCH ON WEEKDAYS IN MARCH 2022



Through exploration of different price signals that could be used for optimal dispatch, we learned that the optimal UC and optimal GHG scenarios can deliver similar customer bill savings to actual dispatch ($13-$14 per kWh of capacity). Additionally, we learned that the optimal UC and optimal GHG scenarios would deliver similar reductions in GHG emissions (54 and 56 kg per kWh of capacity, respectively), while providing an improvement in GHG emissions reductions over actual dispatch. It will be interesting to see how customers respond to a utility cost price signal in the upcoming Real-Time Pricing pilots (starting in June, 2024), which have the possibility of maximally reducing utility costs while maintaining reasonable customer bill savings and increasing the level of GHG emissions reductions.

6.8 POPULATION IMPACTS

The previous sections presented the analyses conducted to showcase the impacts of sampled generation and energy storage systems. These analyses were intended to highlight how SGIP systems were behaving in 2022 and how they were performing to meet program objectives. These analyses were all based on sampled systems from a larger population of SGIP systems. In this section, metered data from the sample of projects were used to estimate population total impacts for 2022.

Section 4 provides more detail into how each of these samples were developed, but they are summarized below in Table 6-8 and Table 6-9. Overall, our team evaluated 3,865 energy storage systems (624 MWh of total energy storage capacity) and 238 generation systems (192 MW of total program generation capacity) receiving upfront payments prior to December 31st of 2022. The energy storage sample represents 11% of the total population by project count and 47% of the total population capacity, with the generation sample representing 56% of both project count and rebated capacity. Again, large nonresidential storage systems and residential storage systems represent the most significant percentage of the population – in terms of capacity – and have the greatest influence on overall SGIP storage population impacts, whereas all-electric fuel cells and gas turbines represent the greatest influence on generation population impacts.

TABLE 6-8: SAMPLE COMPOSITION OF 2022 SGIP STORAGE POPULATION BY CUSTOMER SECTOR

Customer Sector	Sample n	Population N	% of Projects Sampled	Sample Capacity (MWh)	Population Capacity (MWh)	% of Capacity Sampled
Nonresidential	1,056	1,350	78%	567	660	86%
Residential	2,809	35,431	8%	57	671	8%
Total	**3,865**	**36,781**	**11%**	**624**	**1,331**	**47%**

TABLE 6-9: SAMPLE COMPOSITION OF 2022 SGIP GENERATION POPULATION BY TECHNOLOGY TYPE

Technology Type	Sample n	Population N	% of Projects Sampled	Sample Capacity [MW]	Population Capacity [MW]	% of Capacity Sampled
Fuel Cell Electric	175	279	63%	53	116	46%
Fuel Cell CHP	11	33	33%	10	18	57%
Gas Turbine	4	8	50%	77	99	78%
Internal Combustion Engine	26	51	51%	31	57	54%
Microturbine	6	18	33%	3	14	22%
Wind	7	24	29%	15	35	42%
Pressure Reduction Turbine	9	9	100%	3	3	100%
Waste Heat to Power	0	1	0%	0	0	0%
Total	**238**	**423**	**56%**	**192**	**342**	**56%**

Below we summarize the population estimates for several program impact metrics. Population project counts are also reported in the tables. Population estimates were calculated for the following in 2022:

- Electric energy – total energy generated or charged & discharged, capacity factors, and electrical and system efficiencies or overall roundtrip efficiency
- CAISO system peak demand – total CAISO top hour impacts and total top 100-hour impacts

- Environmental Impacts – total GHG impacts
- Utility Avoided Costs – total utility avoided costs

TABLE 6-10: 2022 STORAGE POPULATION ELECTRIC ENERGY IMPACTS

Customer Sector	Population N	Population Discharge (MWh)	Population Charge (MWh)	Population Net Discharge (MWh)	Population RTE
Nonresidential	1,350	83,860	100,028	-16,168	84%
Residential	35,431	7,594	8,899	-1,305	85%
Total	**36,781**	**91,454**	**108,927**	**-17,473**	**84%**

TABLE 6-11: 2022 GENERATION POPULATION ELECTRIC ENERGY IMPACTS

Technology Type	Population N	Population Generation [GWh]	Population CF	Population Electrical Efficiency	Population System Efficiency
Fuel Cell Electric	279	626	69.0%	46.4%	46.4%
Fuel Cell CHP	33	60	26.4%	34.1%	44.6%
Gas Turbine	8	674	72.8%	35.0%	79.3%
Internal Combustion Engine	51	216	39.7%	30.8%	67.0%
Microturbine	18	60	51.5%	29.5%	61.5%
Wind	24	76	24.3%	--	--
Pressure Reduction Turbine	9	7	20.6%	--	--
Waste Heat to Power	1	0	--	--	--
Total	**423**	**1720**	**--**	**--**	**--**

CAISO system peak demand impacts are summarized in Table 6-12 and Table 6-13 for the gross and net top hours. In 2022 the CAISO statewide system gross load peaked at over 51,000 MW on September 6th. The CAISO peaked, from a net load perspective, on September 5th. SGIP generation projects provided a peak hour benefit by generating 180 MW of power during the CAISO Gross peak hour, and 182 MW of power during the CAISO Net peak hour.

Note that the project count below is less than the total population (as indicated in the table above). This estimate is based on all systems that were conducting normal operations during the peak hours in 2022.

TABLE 6-12: 2022 ENERGY STORAGE CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS AND NET PEAK HOUR)

Customer Sector	Population N	Population Gross Peak Hour Net Discharge [MW]	Population Net Peak Hour Net Discharge [MW]
Nonresidential	1,350	23.4	45.1
Residential	35,431	32.7	44.7
Total	**36,781**	**56.1**	**89.8**

TABLE 6-13: 2022 GENERATION CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS AND NET PEAK HOUR)

Technology Type	Population N	Population Gross Peak Hour Generation [MW]	Population Net Peak Hour Generation [MW]
Fuel Cell Electric	248	59.09	60.90
Fuel Cell CHP	23	9.05	7.68
Gas Turbine	8	88.44	88.42
Internal Combustion Engine	50	12.95	15.18
Microturbine	18	5.63	5.24
Wind	21	3.17	3.21
Pressure Reduction Turbine	9	2.36	1.37
Waste Heat to Power	1	0	0
Total	**378**	**180.69**	**181.99**

The total impacts across the top 100 gross and net CAISO hours are presented below in Table 6-14 and Table 6-15. In some cases, the system count is greater across the top 100 hours because some systems began normal operations and received their upfront payment after the peak hour had passed but there were still some top 100 hours left in the year.

TABLE 6-14: 2022 ENERGY STORAGE CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 100 GROSS AND NET HOURS)

Customer Sector	Population N	Population Gross Top 100 Hour Net Discharge [MWh]	Population Net Top 100 Hour Net Discharge [MWh]
Nonresidential	1,350	18.2	22.1
Residential	35,431	21.5	29.7
Total	**36,781**	**39.7**	**51.8**

TABLE 6-15: 2022 GENERATION CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 100 GROSS AND NET HOURS)

Technology Type	Population N	Population Average Gross Top 100 Hour Generation [MWh]	Population Average Net Top 100 Hour Generation [MWh]
Fuel Cell Electric	255	61.7	62.5
Fuel Cell CHP	23	7.1	7.1
Gas Turbine	8	87.1	88.0
Internal Combustion Engine	50	17.1	17.8
Microturbine	18	5.9	5.9
Wind	21	3.0	1.7
Pressure Reduction Turbine	9	1.6	1.5
Waste Heat to Power	1	0	0
Total	**385**	**183.5**	**184.5**

Greenhouse gas impacts during 2022 are summarized in Table 6-16 and Table 6-17. Positive greenhouse gas impacts reflect increased emissions. The magnitude and the sign of greenhouse gas impacts are dependent on the timing of charge and discharge for storage systems. For generation systems, the magnitude and sign of impacts have more to do with the fuel type and baseline type, as renewably fueled systems tend to reduce emissions, and systems with vented baselines reduce emissions significantly more than flared baselines.

Both the residential and nonresidential energy storage sectors contributed to a decrease in GHG emissions in 2022. This was largely an effect of charging systems from on-site PV generation in morning hours when marginal emissions were lower than afternoon and evening hours (Section 6.4). Systems were either trying to maintain zero net load during these higher marginal emission hours or responding to TOU price signals. On average, residential systems decreased GHG emissions by roughly 16 kg/kWh and nonresidential systems decreased emissions by roughly 3.5 kg/kWh. The magnitude of GHG emission reductions within the residential sector combined with reductions within the nonresidential sector for the first time – different from previous years – has contributed to an SGIP energy storage population becoming a net GHG reducer in 2022.

TABLE 6-16: 2022 ENERGY STORAGE POPULATION GREENHOUSE GAS IMPACTS

Customer Sector	N	Population Impact (MT CO_2)	Capacity MWh	MT / Capacity MWh
Nonresidential	1,350	-2,332	660	-3.5
Residential	35,431	-10,705	671	-15.9
Total	**36,781**	**-13,037**	**1,331**	**-9.8**

TABLE 6-17: 2022 GENERATION POPULATION GREENHOUSE GAS IMPACTS

Technology Type	Fuel Type	Baseline Type	Population N	Population GHG Impact [MT CO_{2eq}]	GHG Impact Rate [MT CO_{2eq}/MWh]
Fuel Cell Electric	Renewable Gas	Flare	1	-33	-0.41
		Vent	1	-4,316	-3.78
	Non-Renewable Gas	N/A	277	40,324	0.14
Fuel Cell CHP	Renewable Gas	Flare	6	-4,536	-0.33
	Non-Renewable Gas	N/A	27	6,176	0.13
Gas Turbine	Renewable Gas	Flare	1	-40,955	-0.54
	Non-Renewable Gas	N/A	7	-20,826	-0.03
Internal Combustion Engine	Renewable Gas	Flare	26	-60,251	-0.53
		Vent	7	-63,953	-5.27
	Non-Renewable Gas	N/A	18	4,628	0.05
Microturbine	Renewable Gas	Flare	7	-2,823	-0.48
	Non-Renewable Gas	N/A	9	8,141	0.18
	Other	Flare	2	-5,383	-0.52
Wind	Other	N/A	24	-23,974	-0.32
Pressure Reduction Turbine	Other	N/A	9	-2,679	-0.36
Waste Heat to Power	Other	N/A	1	0	0
Total	--	--	--	**-170,461**	**-0.10**

Utility marginal cost impacts during 2022 are summarized in Table 6-18 and Table 6-19. The evaluation found SGIP incentivized energy storage systems provided a utility-level population benefit of over $27 million in avoided costs across both storage sectors, while generation systems provided utility-level population benefits of over $146 million. These results are consistent with the analyses presented in Section 6.5. Nonresidential and residential storage systems were generally discharging during hours that were capacity or distribution constrained, especially during the summertime, while generation systems typically provided a baseload that didn't vary much throughout the day or year. On average, nonresidential storage systems provided a benefit in avoided cost of roughly $16/kWh and residential storage systems provided a benefit of $25/kWh, while generation systems provided a benefit in avoided cost between $193 per rebated kW capacity for wind turbines to $908 per rebated capacity for gas turbines.

TABLE 6-18: 2022 ENERGY STORAGE UTILITY MARGINAL COST IMPACTS

Customer Sector	Population N	Population Impact (Avoided Cost $)
Nonresidential	1,350	$10,409,824
Residential	35,431	$16,816,228
Total	**36,781**	**$27,226,051**

TABLE 6-19: 2022 GENERATION UTILITY MARGINAL COST IMPACTS

Technology Type	Population N	Population Impact (Avoided Cost $)
Fuel Cell Electric	248	$60,345,441
Fuel Cell CHP	23	$4,979,167
Gas Turbine	8	$46,414,483
Internal Combustion Engine	50	$21,082,766
Microturbine	18	$5,899,561
Wind	21	$6,703,018
Pressure Reduction Turbine	9	$1,241,489
Waste Heat to Power	1	$0
Total	**378**	**$146,665,915**

APPENDIX A BILL SAVINGS ANALYSIS

We estimated bill savings for the 2021 and 2022 SGIP energy storage evaluation through use of Verdant's distributed energy resource cost effectiveness analysis tool (DER CAT). Monthly and annual bills were estimated using the tool's bill calculation module. To estimate bill savings, we calculated a customer's bill using their historical hourly net load and an estimated baseline load. The baseline load was defined as the net load minus the hourly storage dispatch activity. Bill savings were calculated as the difference between the actual and baseline bills.

Table A-1 and Table A-2 present the actual rate schedules used to develop 2021 and 2022 bill impacts for residential and nonresidential SGIP participants, respectively. These are further disaggregated by IOU.

TABLE A-1: DISTRIBUTION OF RESIDENTIAL RATE SCHEDULES IN ANALYSIS BY IOU AND YEAR

IOU	Rate Schedule	2021		2022	
		Sample Count	Percent (%)	Sample Count	Percent (%)
PG&E	AG-A1	0	0%	1	<1%
	B-1	1	<1%	3	<1%
	B-19	1	<1%	0	0%
	B-6	1	<1%	1	<1%
	E-1	25	3%	51	4%
	E-6	4	<1%	5	<1%
	E-TOU-B	29	3%	28	2%
	E-TOU-C	353	41%	472	34%
	E-TOU-D	29	3%	34	2%
	EM	1	<1%	1	<1%
	EM-TOU	2	<1%	2	<1%
	EV-A	55	6%	61	4%
	EV2-A	358	42%	720	52%
	Subtotal	**859**	**100%**	**1,379**	**100%**
SCE	D	42	8%	41	6%
	D-CARE	2	<1%	3	<1%
	TOU-D-A	119	24%	103	15%
	TOU-D-B	15	3%	12	2%
	TOU-D-B-CARE	1	<1%	1	<1%
	TOU-D-PRIME	176	35%	326	48%
	TOU-D-PRIME-CARE	6	1%	16	2%

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	TOU-D-T	4	1%	3	<1%
	TOU-D-T-CARE	1	<1%	1	<1%
	TOU-D_4_9	103	21%	110	16%
	TOU-D_4_9-CARE	2	<1%	1	<1%
	TOU-D_4_9-FERA	1	<1%	1	<1%
	TOU-D_5_8	16	3%	45	7%
	TOU-D_5_8-CARE	2	<1%	7	1%
	TOU-GS1-A	2	<1%	3	<1%
	TOU-GS1-E	4	1%	7	1%
	Subtotal	**496**	**100%**	**680**	**100%**
SDG&E	DR	46	17%	36	10%
	DRSES	53	19%	70	20%
	EV-TOU-2	13	5%	14	4%
	EV-TOU-5	25	9%	38	11%
	GDRSES	11	4%	9	3%
	GEV-TOU2	2	1%	2	1%
	TOU-DR	28	10%	27	8%
	TOU-DR1	88	32%	145	42%
	TOU-DR2	6	2%	7	2%
	Subtotal	**272**	**100%**	**348**	**100%**
All	**Total**	**1,627**		**2,407**	

TABLE A-2: DISTRIBUTION OF NONRESIDENTIAL RATE SCHEDULES IN ANALYSIS BY IOU AND YEAR

IOU	Rate Schedule	2021		2022	
		Sample Count	Percent (%)	Sample Count	Percent (%)
PG&E	A-6	3	1%	2	1%
	A10-X	6	2%	6	2%
	AG-5-B	1	<1%	1	<1%
	AG-A1	1	<1%	1	<1%
	AG-B	1	<1%	0	0%
	AG-C	3	1%	3	1%
	B-1	5	2%	5	2%
	B-10	23	8%	17	6%
	B-19	144	49%	149	55%

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	B-19_1v	7	2%	4	1%
	B-20_1v	15	5%	14	5%
	B-20_2v	4	1%	5	2%
	B-20_t	6	2%	7	3%
	B-6	5	2%	2	1%
	E-19	43	15%	36	13%
	E-19_1v	12	4%	11	4%
	E-20_1v	11	4%	6	2%
	E-20_2v	1	<1%	1	<1%
	Subtotal	**291**	**100%**	**270**	**100%**
SCE	D-CARE	2	<1%	0	0%
	TOU-8-B	14	3%	6	1%
	TOU-8-D	98	20%	95	22%
	TOU-8-E	4	1%	8	2%
	TOU-8-R	15	3%	12	3%
	TOU-D-PRIME	0	0%	1	<1%
	TOU-D_4_9	1	<1%	0	0%
	TOU-EV-NR-8	6	1%	15	4%
	TOU-GS1-A	1	<1%	0	0%
	TOU-GS1-D	1	<1%	1	<1%
	TOU-GS1-E	1	<1%	0	0%
	TOU-GS2-B	29	6%	8	2%
	TOU-GS2-D	56	12%	54	13%
	TOU-GS2-E	17	4%	18	4%
	TOU-GS2-R	72	15%	65	15%
	TOU-GS3-B	16	3%	11	3%
	TOU-GS3-D	81	17%	70	16%
	TOU-GS3-E	9	2%	11	3%
	TOU-GS3-R	41	8%	31	7%
	TOU-PA2-A	5	1%	3	1%
	TOU-PA2-D	5	1%	4	1%
	TOU-PA2-E	4	1%	6	1%
	TOU-PA3-D	2	<1%	5	1%
	TOU-PA3-E	3	1%	1	<1%

	Subtotal	**483**	**100%**	**425**	**100%**
SDG&E	A6-TOU_1v	1	1%	2	1%
	AL-TOU2_<500kW_1v	15	10%	11	7%
	AL-TOU_<500kW_1v	114	74%	109	73%
	AL-TOU_<500kW_2v	0	0%	1	1%
	AL-TOU_>500kW_1v	23	15%	25	17%
	AL-TOU_>500kW_2v	1	1%	1	1%
	OL-TOU	1	1%	1	1%
	Subtotal	**155**	**100%**	**150**	**100%**
All	**Total**	**929**		**845**	

Updating the Model

The DER CAT contains detailed IOU tariff information that is used to calculate customer bills. For this analysis, we entered rate information for tariffs as of January 2022. The tool captures full information about TOU periods, tiered rates, and demand charges. Figure A-1 shows an example of hour the TOU periods are captured inside the model.

FIGURE A-1: DER CAT HOURLY TIME-OF-USE INPUT SHEET

RateName	Season	WeekEndHoliday	H00	H01	H02	H03	H04	H05	H06	H07	H08	H09	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23
TOU-DR1	Summer	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Summer	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Summer	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off

All sub-components of an individual tariff are captured for energy and demand charges. Figure A-2 shows an example of the rate components that are recorded in the tool. The rate's subcomponents are tracked separately so that non-bypassable charges are handled appropriately in bill calculations. Demand charges are also recorded in the tool, separating out peak, non-coincident, and TOU charges for transmission and distribution.

FIGURE A-2: DER CAT RATE INPUT SHEET

Season	TOU	Tier	Transm	Distr	PPP	ND	CTC	LGC	RS	TRAC	CostRe	PUCRF	BaselineDis	UDC	DWRBond	EECCDWR	TotalNBP	TotalRate
Summer	On	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.43976	0.0262	0.69702
Summer	Off	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.19788	0.0262	0.45514
Summer	SuperOff	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.07083	0.0262	0.32809
Winter	On	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.14857	0.0262	0.54517
Winter	Off	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.08335	0.0262	0.47995
Winter	SuperOff	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.06442	0.0262	0.46102
Summer	_ALL_												-0.10159	-0.10159			0	-0.10159
Winter	_ALL_												-0.10159	-0.10159			0	-0.10159

Bill Calculation

Each annual bill is calculated by first summarizing the monthly kW and kWh by tier and/or TOU period. These monthly totals are then multiplied by the applicable $/kW or $/kWh provided in the given utility rate sheet. This process allows many different rate structures to be utilized in the same calculator. The annual bill is then calculated by summing each of the monthly kW and kWh components. The bill calculations assume that the monthly billing cycles align with calendar months. Exports were reimbursed at the full retail rate (NEM 2.0). The billing analysis for this project involves estimating bills for each customer under two scenarios: actual customer usage with a battery, and customer usage if their system was not paired with battery storage. The bill calculation tool is run over the usage from both scenarios, creating annual bills for both scenarios. The difference between these bills is the bill savings we report.

VERDANT

APPENDIX B DATA SOURCES AND QUALITY CONTROL

This appendix provides an overview of the primary sources of data used to quantify the energy and peak demand impacts of the 2021-2022 Self-Generation Incentive Program (SGIP) and the data quality and validation process.

B.1 DATA SOURCES

The primary sources of data include:

- The statewide project list managed by the Program Administrators (PAs),
- Site inspection and verification reports completed by the PAs or their consultants,
- Metered storage and generation data provided by project developers, the SGIP Data Portal, directly from customers, or from performance data providers,
- Metered load and PV generation data from project developers, and
- Interval load data provided by the electric utilities.

B.1.1 Statewide Project List and Site Inspection Verification Reports

The statewide project list contains information on all projects that have applied to the SGIP. Critical fields from the statewide project list include:

- Project tracking information such as the reservation number, facility address, program year, payment status/date, and eligible/ineligible cost information, and
- Project characteristics including technology/fuel type, rebated capacity, fuel types, and equipment manufacturer/model.

Data obtained from the statewide project list are verified and supplemented by information from site inspection verification reports. The PAs or their consultants perform site inspections to verify that installed SGIP projects match the application data and to ensure they meet minimum requirements for program eligibility. Our team reviews the inspection verification reports to verify and supplement the information in the statewide project list. Additional information in verification reports includes descriptions of storage and generation capacity, differences between incentivized and nameplate capacities, and identification of existing metering equipment that can be used for impact evaluation purposes, fuel descriptions and percentage of biogas, and details surrounding heat recovery.

B.1.2 Interval Load Data and Metered Data

Metered energy storage charge and discharge data are requested and collected from system manufacturers and developers for performance-based incentive (PBI) and non-PBI projects, and from Energy Solutions for projects that received a PBI incentive. Metered energy generation, fuel consumption, and heat recovery data were requested directly from customers and performance data providers, as well as downloaded from the Energy Solutions data portal for those projects still within their PBI period. Interval load data for each project were requested from Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2021 and 2022. These data were requested to allow analysis of noncoincident peak (NCP) demand impacts and to better analyze energy storage dispatch. Due to the confidential nature of customer load data, we signed nondisclosure agreements (NDAs) with each of the utilities to obtain the load data. Once load data were received and processed, we matched them to available charge/discharge data to allow project-by-project analysis of the customer demand impacts of SGIP. Table B-1 provides a summary of the types of data requested and used in the analysis as well as the data source(s).

TABLE B-1: DATA REQUESTED AND DATA SOURCES

Types of Data Requested/Used/Received	SGIP Project Database	Energy Solutions	Project Developers	Customers	PDPs	IOU
SGIP reservation number	X	X	X			
Capacity (kW, duration, kWh for Storage), kW for generation	X		X			
Program year (PY) of application and upfront payment date	X					
Customer sector	X					
Payment type (PBI vs. Non-PBI)	X	X				
Incentive	X					
Project developer	X		X			
Battery manufacturer	X		X			
Interval Charge and discharge data (kWh)		X	X			
Interval electrical generation, fuel consumption, and heat recovery		X	X	X	X	
15-minute customer load data (kWh)			X			X
Renewable on-site generation (kWh)			X			X
Treatment of daylight savings		X	X	X	X	X
Data period beginning or ending		X	X	X	X	X
Unit of measure (kW, kWh, W, Wh, etc)		X	X	X	X	X
Status of storage system (operational/off-line)			X			
Storage system use case – TOU bill arbitrage, coincident/non-coincident demand charge reduction, PV self-consumption, backup, demand response/wholesale market participation			X			
How system interacts with on-site renewable			X			
Customer utility tariff			X			X
Flow Direction (delivered vs. received) for bi-directional meters						X
Dates and times of any DR, capacity or other program participation			X			X
Dates and times of planned/unplanned outages (PSPS, etc)			X			X
SubLAP associated with the geographic location of customer						X

B.2 DATA CLEANING

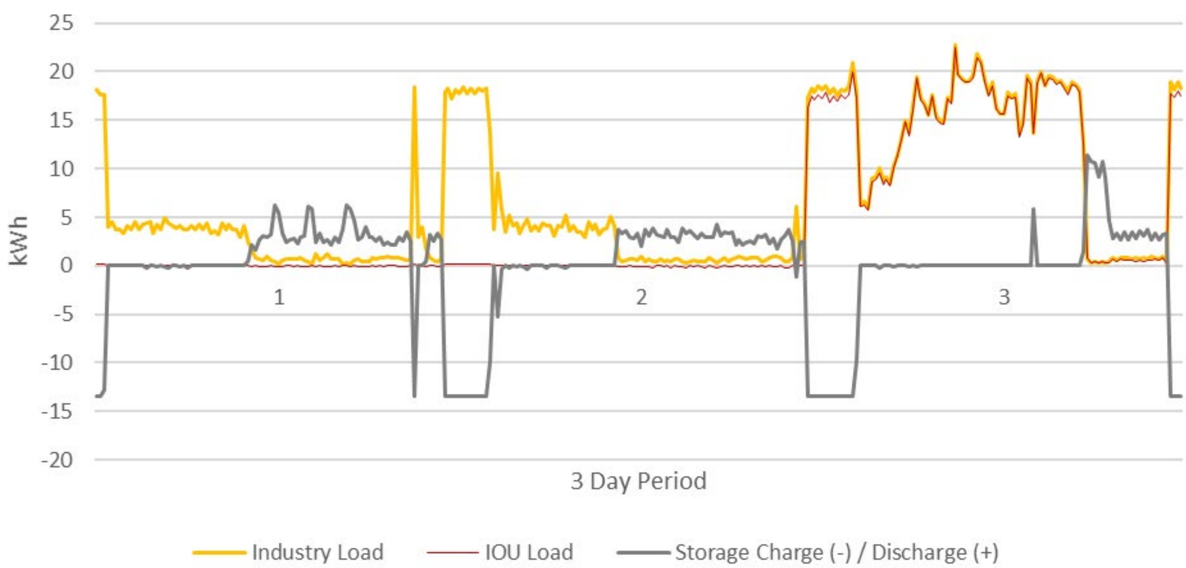
As discussed above, the analysis leveraged a variety of data sources from project developers, Energy Solutions (for projects that received a PBI incentive), directly from customers and performance data providers, and the electric utilities. We conducted an extensive data cleaning and quality control exercise to ascertain whether the data were verifiable:

- Interval battery, electrical generation, fuel consumption, heat recovery, and load data were aligned to Pacific Standard Time (PST). Data for each time interval were set to the beginning of the time interval.
- Visual inspections of storage dispatch, generator, and load data were conducted for all projects where we received data. This allowed the evaluation team to verify if, for example, metered load data increased at the same time interval as the battery was charging (time syncing), or if both fuel consumption and electrical generation showed consistencies. This step also identified sites with differing or inconsistent timestamps, and load data with the wrong sign (i.e. negative when it should be positive and positive when it should be negative).
- When battery data were provided by the project developer and the PBI database, we conducted quality control (QC) on both data streams and, often, stitched the data throughout the year to develop a more robust data set for each project.
- When load data were provided by the project developer and the IOU, we conducted QC on both data streams and, often, stitched the data throughout the year to develop a more robust data set for each project.
- We reviewed hourly, daily and monthly performance metrics to determine whether the data were accurate.
- We reviewed battery capacities and generation capacities in the program tracking database to verify they were accurate.
- We reviewed the battery storage data usage to identify the start date of valid data.
- We identified outliers in battery data by setting any 15-minute charge and discharge power that is above the rated capacity of the battery times four as abnormal spikes. Outliers were also identified in electrical output and fuel generation data.
- We identified battery storage data that signified possible data quality issues:
  - Round trip efficiency over 92.5 percent
  - Maximum battery discharge as a percentage of kW capacity greater than 2
  - The 99th percentile of battery storage discharge as a percentage of kWh capacity greater than 1, indicating the possibility of a second battery installed that was not installed through SGIP

Figure B-1 conveys a visualization of the data cleaning process. This is a three-day example that was mocked up to represent one of the storage projects. The yellow line represents the load data that would have been provided by the project developer. The red line represents the IOU load, and the gray line represents the storage dispatch behavior. This example illustrates a couple of data cleaning exercises we performed:

- We can confirm the sync between the battery and load data. When the battery is charging (-) the load increases on the same time stamp.
- The IOU load data in this representative example is missing throughout the first day and halfway through the second day. The IOU data does not match with the project developer data until midnight on the third day (see between 2 and 3 below). We could stitch the two load streams and not lose the first two days.

FIGURE B-1: EXAMPLE 1 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



We received battery storage data that sometimes started before the interconnected date, but still appeared to be valid, usable data. To retain the most amount of valid data, we reviewed the data received to determine an analysis start date. For most of the sites, this was not an issue, as they we interconnected prior to 2021. However, for the ones that were interconnected in 2021 and 2022, we determined the start date as follows:

- If the upfront payment date came before the date that the battery first cycled then the start date used was the most recent of either the upfront payment date or the first date of any data,
- Else if there was no battery cycling in the winter then the start date used was the first date of any data,

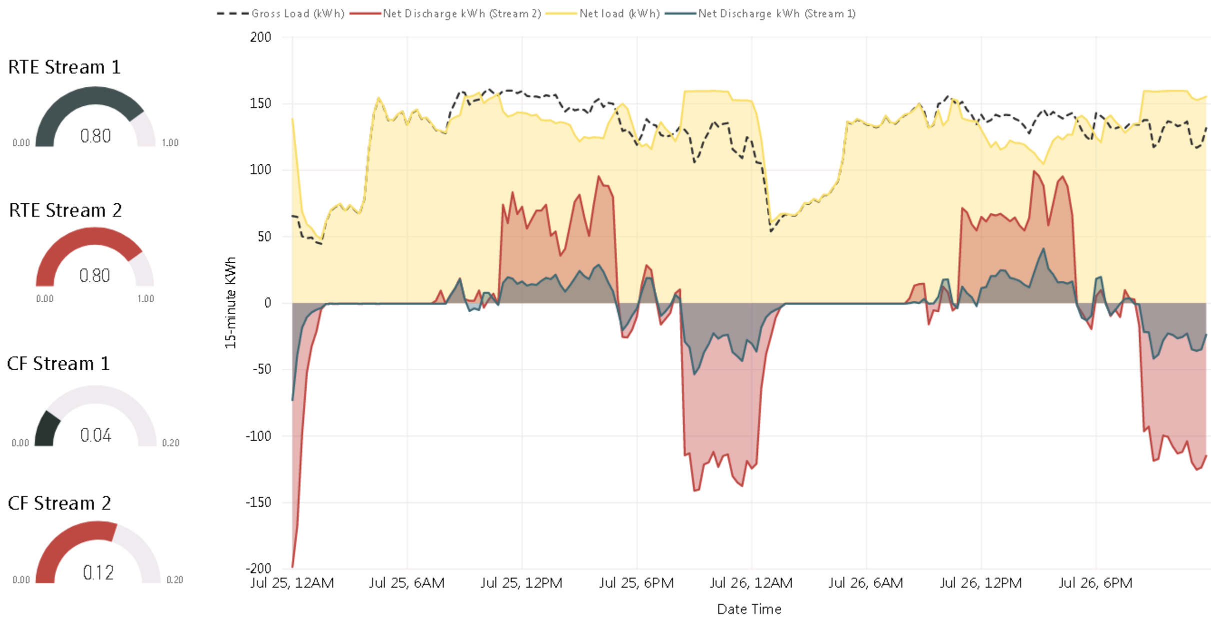
- Else the start date used was the first date the battery started cycling.

Storage systems inherently increase energy consumption. Because of losses in the battery, less energy can be discharged than is stored in the battery. This fact provided an additional QC benefit. After we removed data that was completely missing or clearly corrupt, we examined the roundtrip efficiency (RTE) – which is the ratio of total discharge to total charge energy – for each project by hour, day, and month. Since energy discharged cannot be greater than energy stored, we identified potential data issues by reviewing projects that exhibited RTEs greater than one at the monthly level (Section 6 discusses this performance metric in detail).

For the residential projects, looking for the appearance of a second battery addition was an additional QC step that was implemented in this evaluation. When the 99th percentile of battery storage discharge as a percentage of kWh capacity was greater than 1, we quarantined the sites for review. The time series data was manually reviewed to assess the date of when the additional battery appears, and the storage data was pro-rated after that point so that the savings will only reflect that of the battery installed through the program.

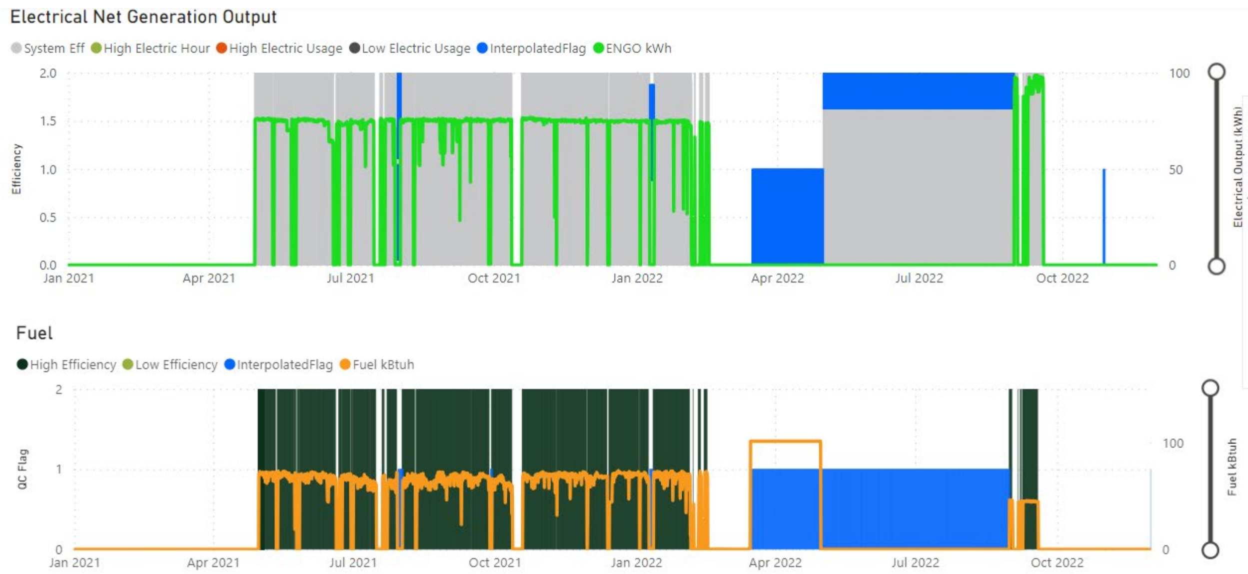
Another QC check was also conducted where the evaluation team received multiple streams of data. Capacity factors and RTEs have expected ranges, therefore observations that fall outside of these ranges are flagged for further review. Figure B-2 illustrates this initial data cleaning step – where we compare the RTE and CF from two distinct data streams. While the RTE for both streams are identical (and within an expected range) the CF for both streams are different. These data are flagged for further analysis. This analysis would reveal that “Stream 1” is the appropriate storage net discharge profile for this project. The magnitude of net discharge for “Stream 2” is too great, given the metered load profile for this facility.

FIGURE B-2: EXAMPLE 2 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



On the generation side, dashboards were developed which included hourly electrical, fuel, and heat data, as well as a calculation of efficiency, and flags indicating whether the electric output appeared too high. An example is shown below in Figure B-3. For this project, the calculated efficiency of the system was between 200-300%, indicating that the fuel data may not be complete, or the electrical output may include output for another generator. In this case, the electrical output seemed reasonable, within the reasonable range based on the size of the generator, but the fuel data could not be validated, so we dropped the fuel data from the analysis, but kept the electrical generation data.

FIGURE B-3: EXAMPLE 3 OF DATA CLEANING AND QC PROCESS FOR A GENERATION PROJECT



One final QC check was implemented to ensure the quality of data was within expected ranges for billing calculation. All of the solar generation data was stratified by meter and hour and normalized by assigning a z-score to each datapoint. Any data points with a z-score greater than 7.5 or less than –7.5 were removed from the final dataset. This retains more than 99.999% of the data, while removing the occasional extremely anomalous value. This process was followed up with manual verification to ensure that the data points being removed were in fact anomalous.

To accurately estimate billing impacts, there can be no missing values in the netload dataset for a given household. If data was missing, or removed in the step previous anomaly detection step, it was replaced with interpolated data from the same meter. In the case of data gaps spanning less than two hours, data was interpolated linearly between the nearest known datapoints. For gaps larger than two hours, the interpolation was done by recreating a hypothetical load based on a matching month, hour, and meter. This may fill in the gap with data from earlier or later in the month and averaged together with the data from the previous year’s load shape as well. To ensure quality interpolation of data, gaps must meet certain requirements: The total amount of data missing must be less than 30% of all data available, and no single gap can be larger than two weeks, or 336 consecutive hours.

APPENDIX C SGIP 2021 PERFORMANCE METRICS & IMPACTS

C.1 OBSERVED PERFORMANCE METRICS

C.1.1 Energy Storage Performance Metrics

Energy Storage Efficiency

FIGURE C-1: AVERAGE 2021 RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

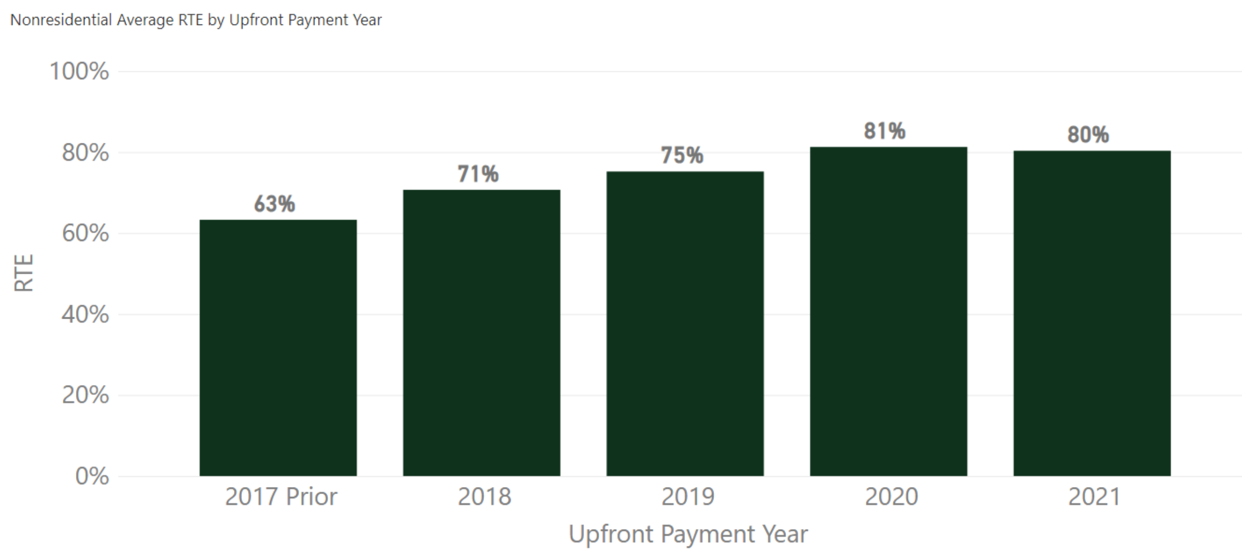


FIGURE C-2: DISTRIBUTION OF 2021 RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

FIGURE C-3: AVERAGE 2021 RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

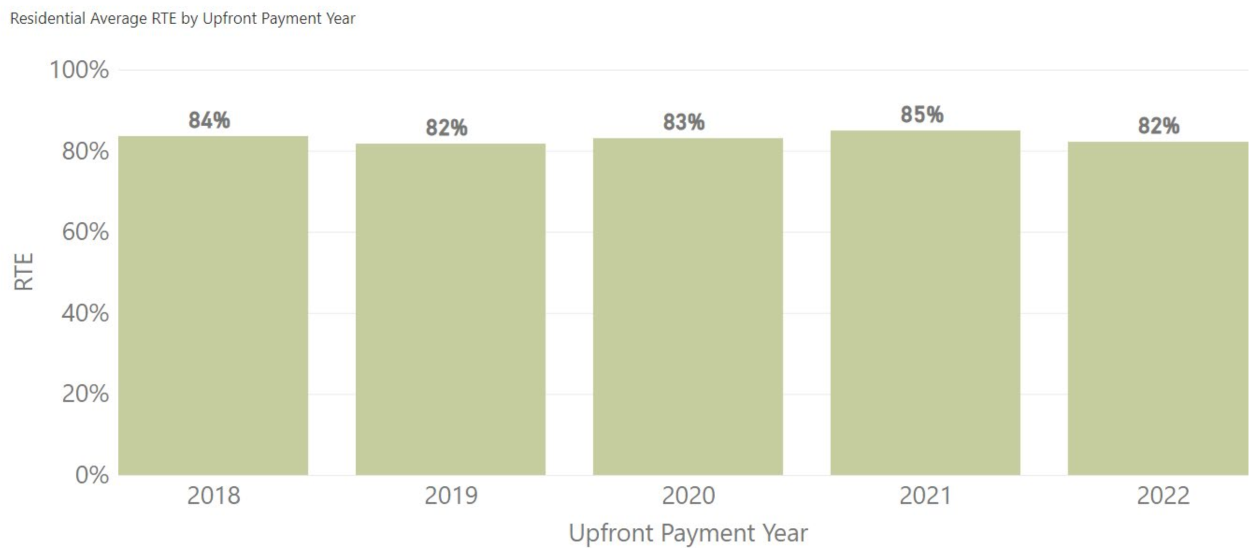
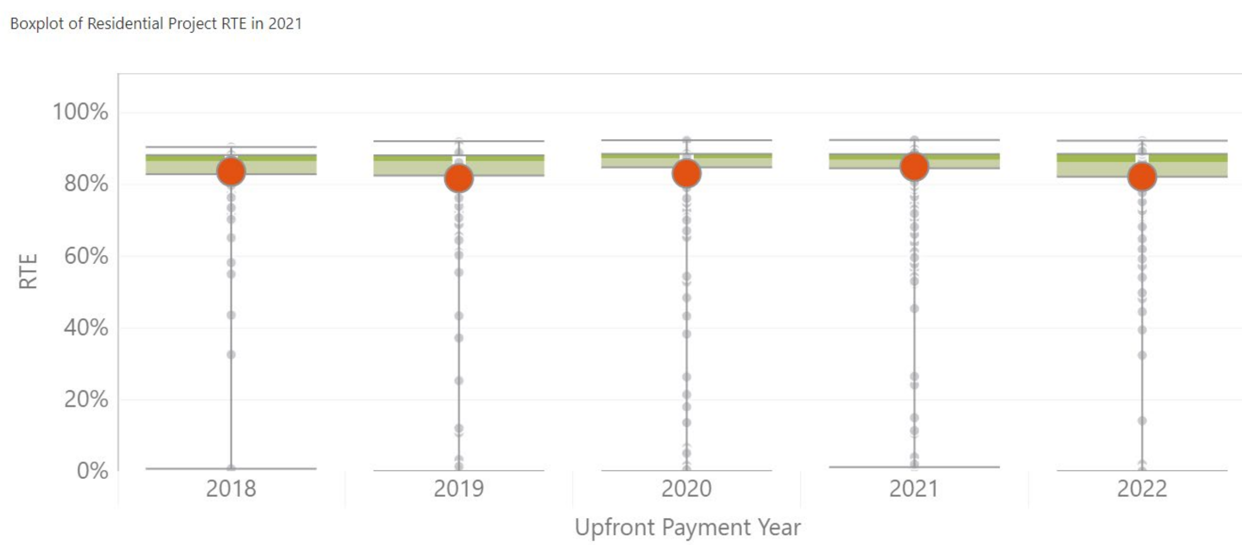


FIGURE C-4: DISTRIBUTION OF 2021 RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Energy Storage Utilization

FIGURE C-5: AVERAGE 2021 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

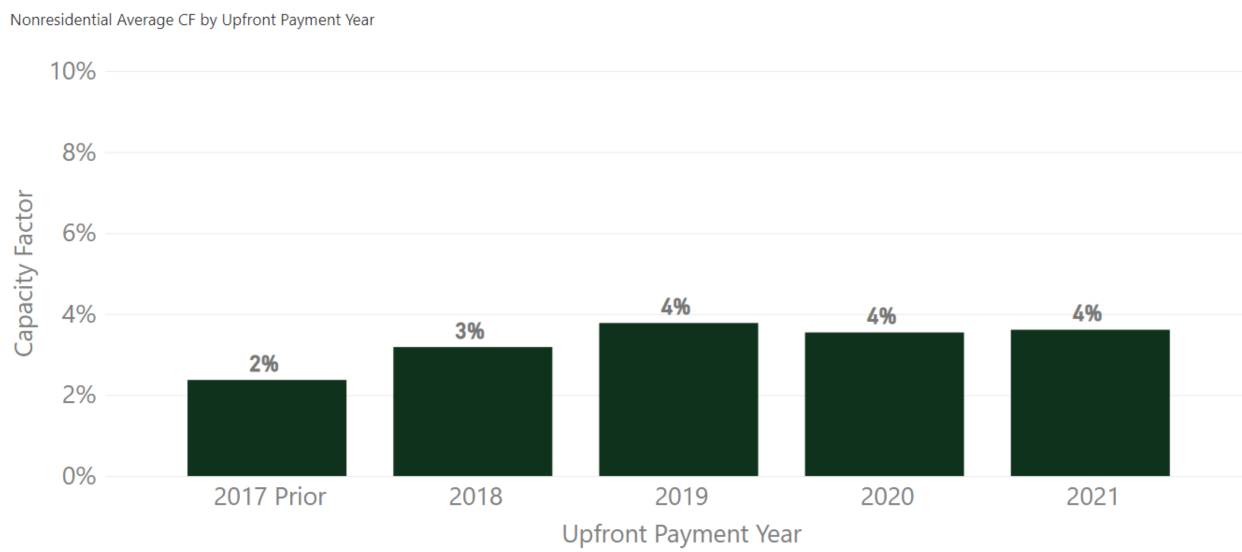


FIGURE C-6: DISTRIBUTION OF 2021 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

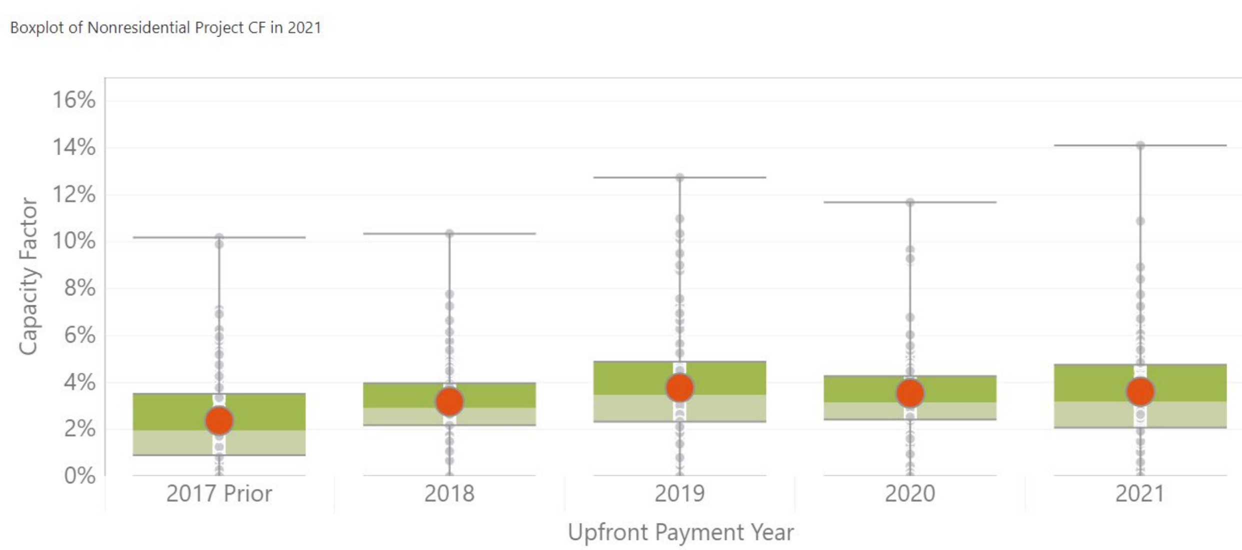


FIGURE C-7: 2021 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY PAYMENT YEAR AND BUDGET CATEGORY

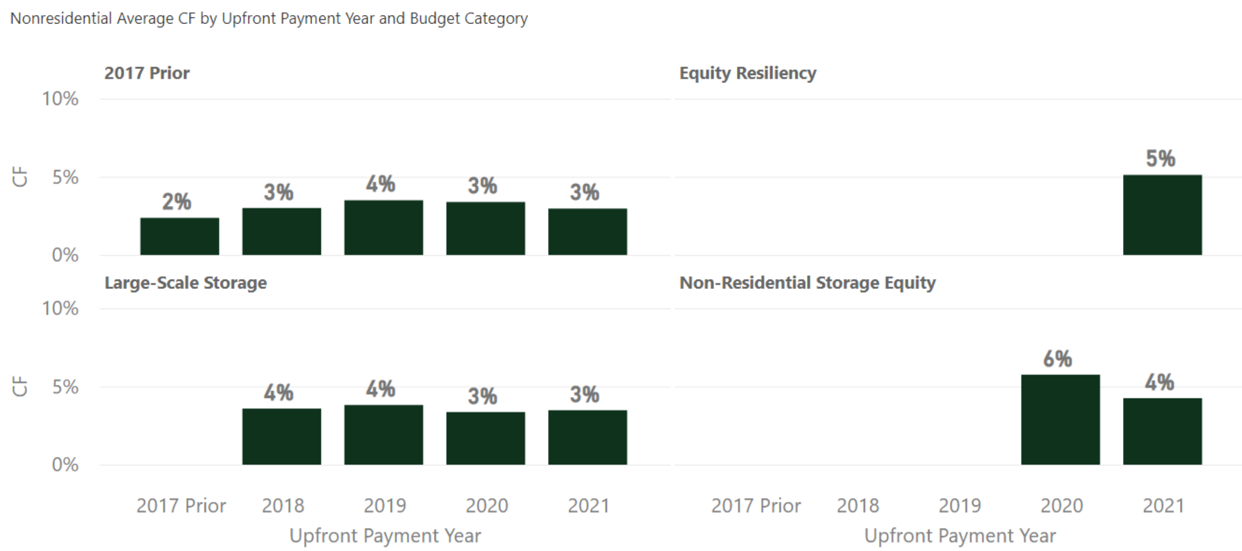


FIGURE C-8: AVERAGE 2021 CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

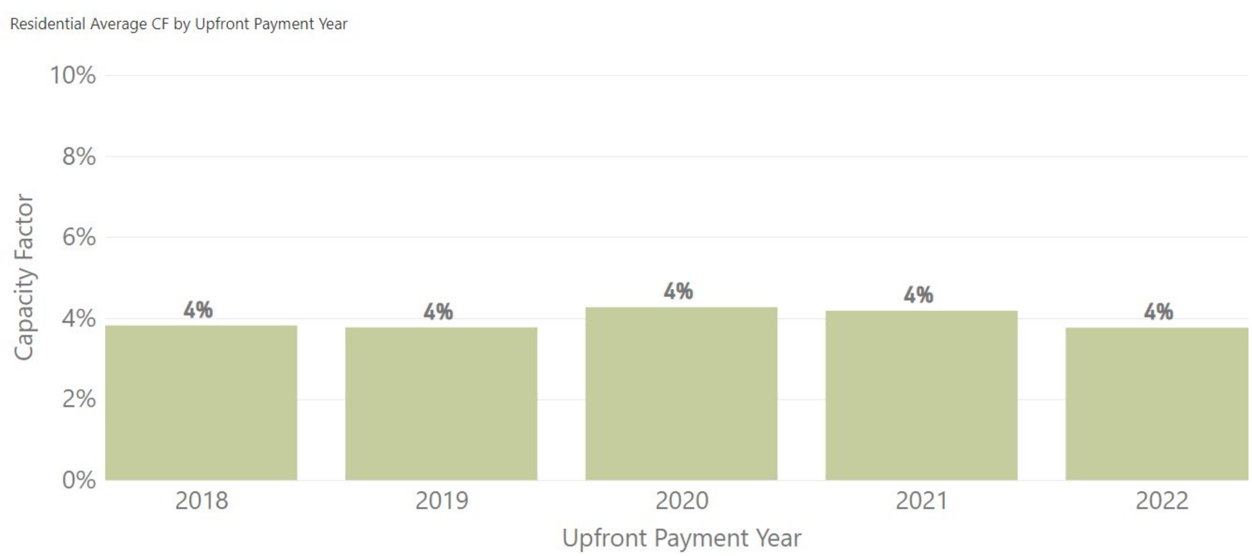


FIGURE C-9: DISTRIBUTION OF 2021 CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

FIGURE C-10: 2021 AVERAGE ANNUAL CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

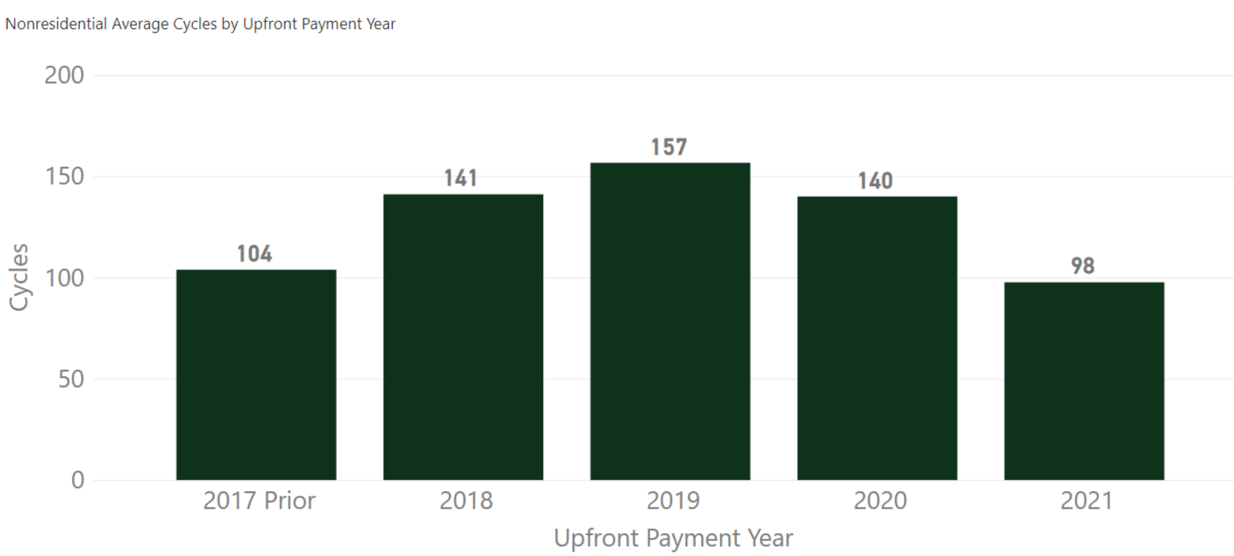


FIGURE C-11: DISTRIBUTION OF 2021 ANNUAL CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

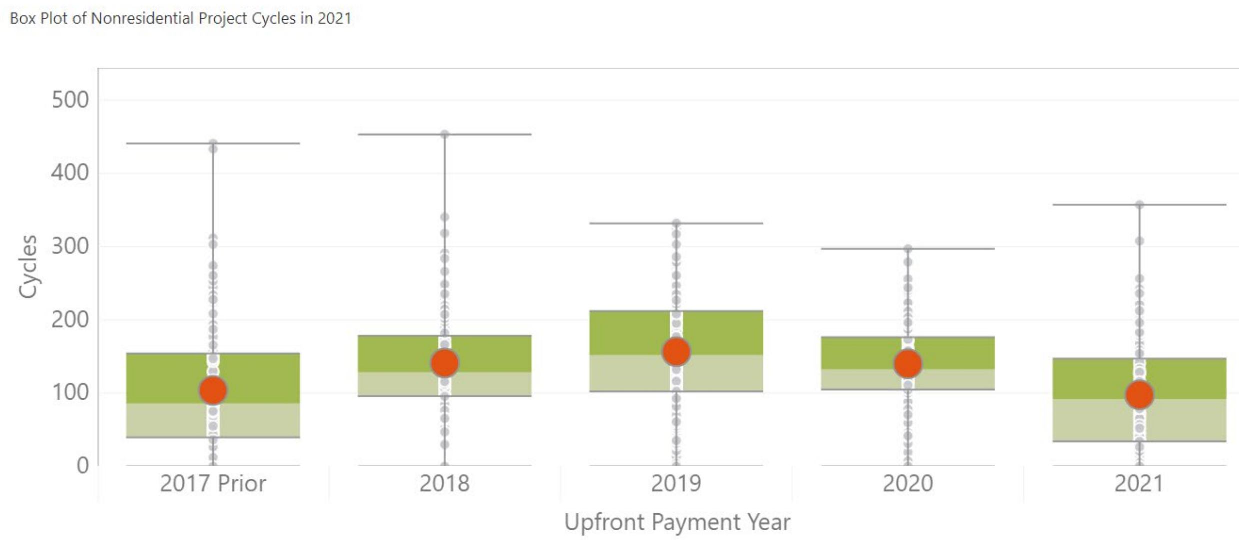


FIGURE C-12: 2021 AVERAGE ANNUAL CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

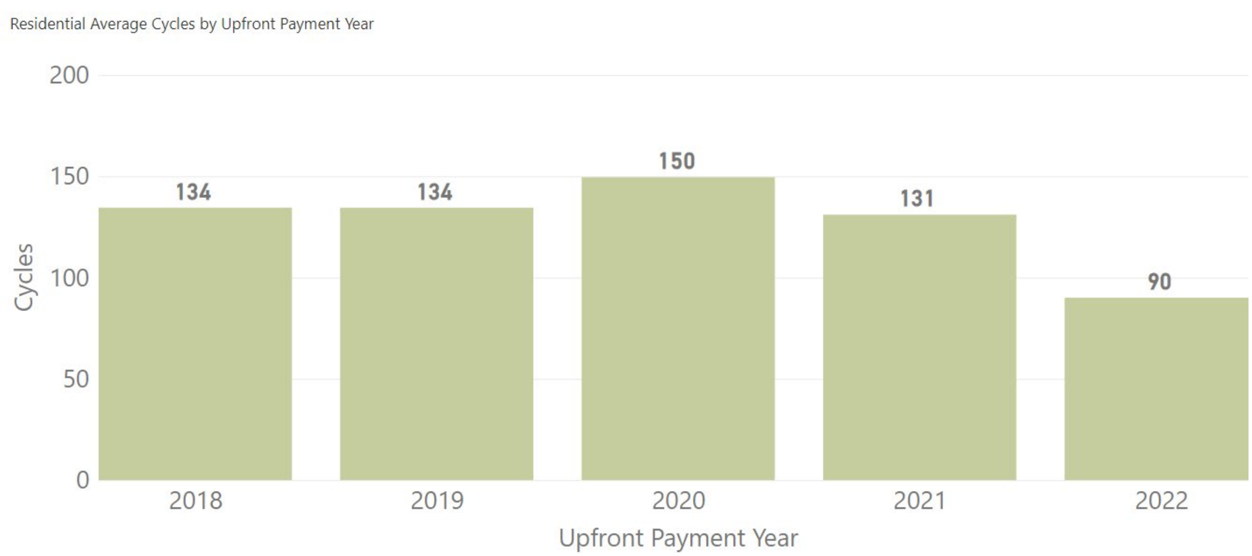


FIGURE C-13: DISTRIBUTION OF 2021 ANNUAL CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

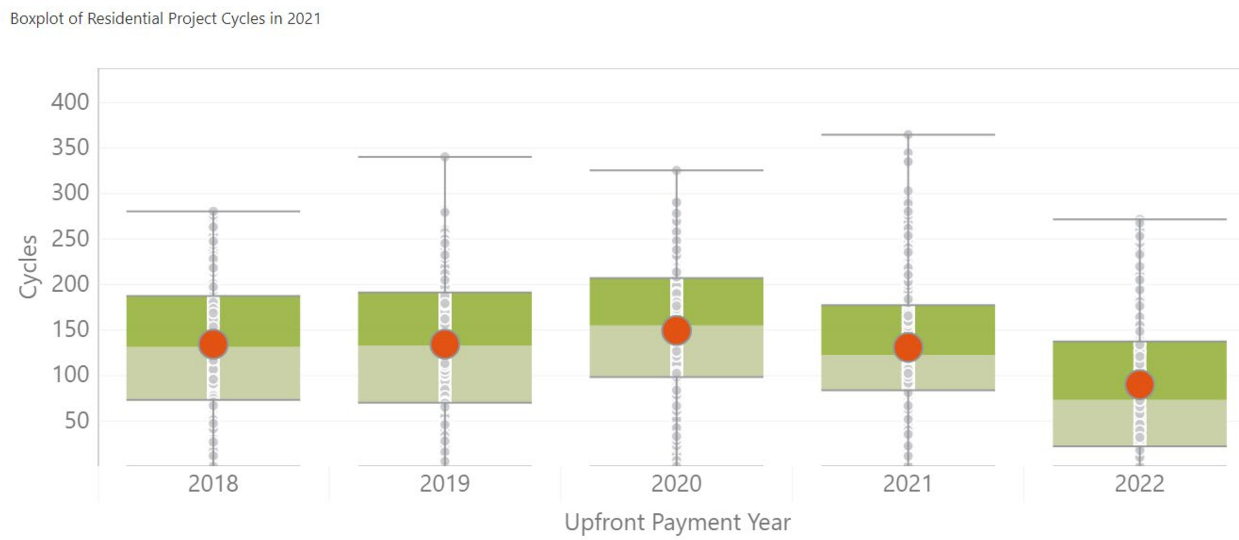


FIGURE C-14: 2021 RTE VERSUS DISCHARGE CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE

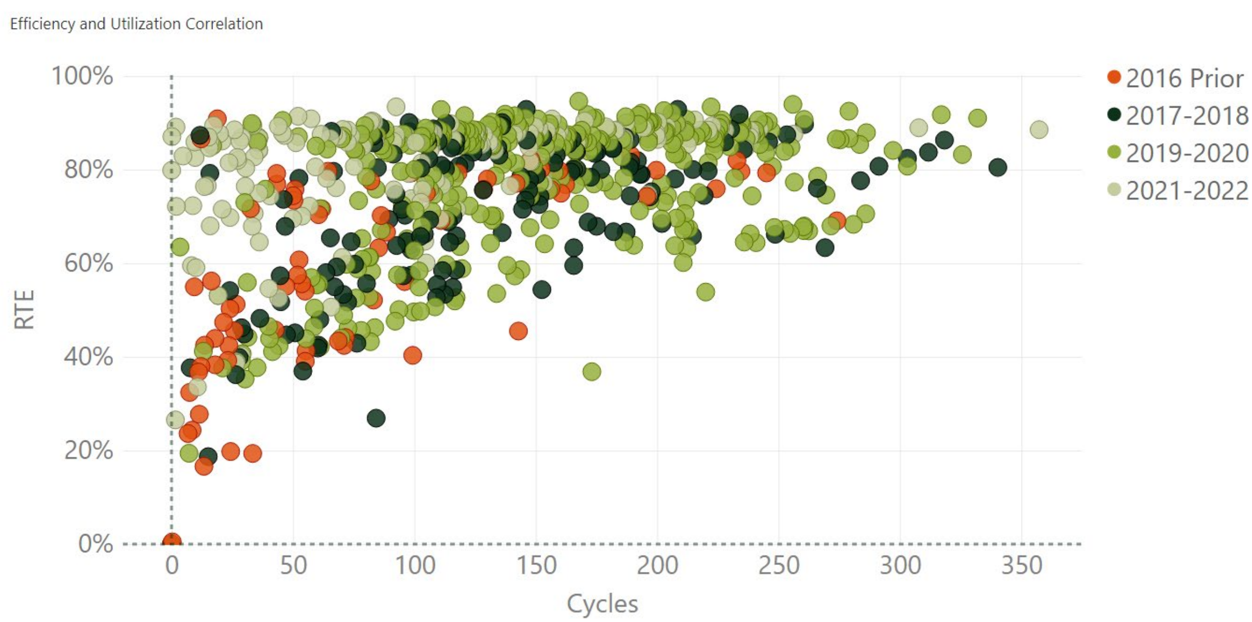
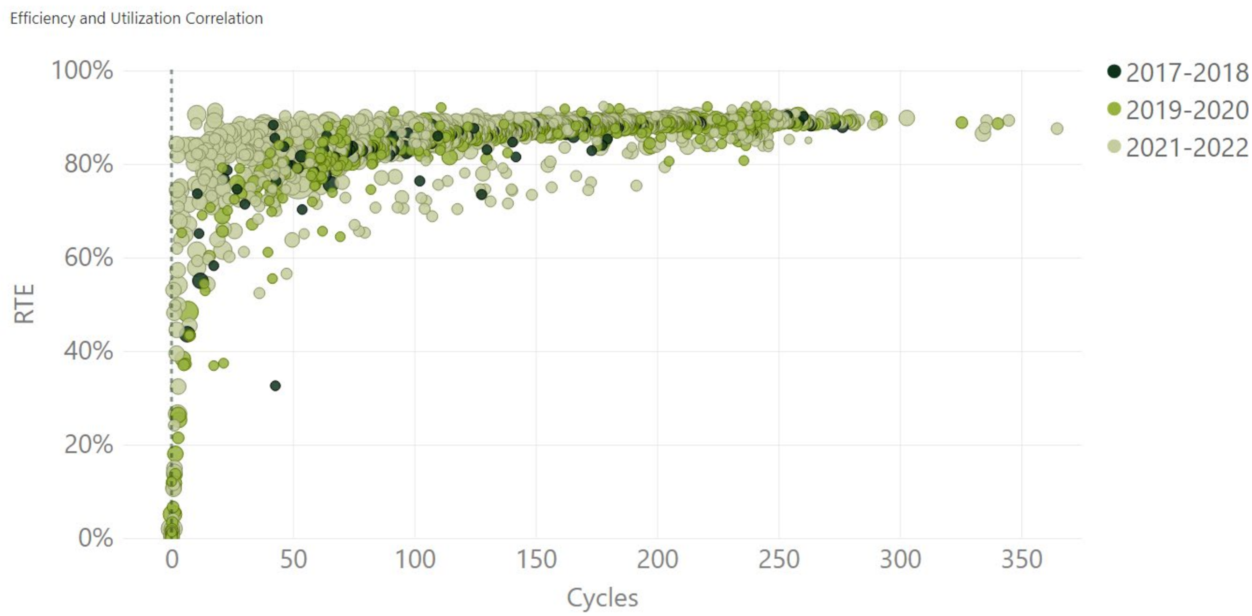


FIGURE C-15: 2021 RTE VERSUS DISCHARGE CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE



Performance Summaries

FIGURE C-16: SUMMARY OF 2021 NONRESIDENTIAL PERFORMANCE METRICS BY PA

PA	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
CSE	142	201	457	73%	4%	6%	130
PG&E	171	289	578	70%	3%	5%	111
SCE	379	297	609	77%	3%	6%	134
SCG	38	406	863	78%	4%	7%	171
Overall	**730**	**282**	**586**	**74%**	**3%**	**6%**	**130**

FIGURE C-17: SUMMARY OF 2021 RESIDENTIAL PERFORMANCE METRICS BY PA

PA	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
CSE	367	8	21	85%	4%	7%	136
PG&E	1195	8	22	83%	4%	6%	118
SCE	675	8	19	85%	5%	8%	153
SCG	28	8	20	84%	5%	8%	145
Overall	**2265**	**8**	**21**	**84%**	**4%**	**7%**	**132**

FIGURE C-18: SUMMARY OF 2021 NONRESIDENTIAL PERFORMANCE METRICS BY PAYMENT YEAR

Upfront Payment Year	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2017 Prior	139	325	651	64%	2%	4%	105
2018	91	271	540	71%	3%	5%	141
2019	238	184	378	75%	4%	6%	157
2020	107	367	793	81%	4%	6%	140
2021	155	344	729	80%	4%	6%	97
Overall	**730**	**282**	**586**	**74%**	**3%**	**6%**	**130**

FIGURE C-19: SUMMARY OF 2021 RESIDENTIAL PERFORMANCE METRICS BY PAYMENT YEAR

Upfront Payment Year	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2018	154	6	16	84%	4%	6%	134
2019	278	7	16	82%	4%	6%	135
2020	489	7	18	83%	4%	7%	151
2021	1083	9	23	85%	4%	7%	132
2022	261	9	24	82%	4%	6%	91
Overall	**2265**	**8**	**21**	**84%**	**4%**	**7%**	**132**

FIGURE C-20: SUMMARY OF 2021 NONRESIDENTIAL PERFORMANCE METRICS BY BUDGET CATEGORY

Budget Category	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2017 Prior	240	314	627	69%	3%	5%	119
Equity Resiliency	4	254	1131	85%	5%	9%	77
Large-Scale Storage	458	273	571	77%	4%	6%	135
Non-Residential Storage Equity	28	171	389	81%	5%	8%	151
Overall	**730**	**282**	**586**	**74%**	**3%**	**6%**	**130**

FIGURE C-21: SUMMARY OF 2021 RESIDENTIAL PERFORMANCE METRICS BY BUDGET CATEGORY

Budget Category	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
Equity Resiliency	511	11	28	84%	4%	6%	107
Large-Scale Storage	109	17	45	84%	3%	6%	105
San Joaquin Valley Residential	4	10	26	83%	2%	4%	14
Small Residential Storage	1641	7	17	84%	4%	7%	141
Overall	**2265**	**8**	**21**	**84%**	**4%**	**7%**	**132**

FIGURE C-22: SUMMARY OF 2021 NONRESIDENTIAL PERFORMANCE METRICS BY PROGRAM YEAR

Program Year	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2014 prior	103	378	757	65%	2%	4%	97
2015	86	326	652	75%	3%	6%	146
2016	51	162	323	68%	3%	5%	118
2017	327	212	437	74%	4%	6%	147
2018	51	476	1033	82%	3%	6%	110
2019	66	387	805	85%	4%	7%	149
2020	46	255	617	80%	4%	6%	63
Overall	**730**	**282**	**586**	**74%**	**3%**	**6%**	**130**

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FIGURE C-23: SUMMARY OF 2021 RESIDENTIAL PERFORMANCE METRICS BY PROGRAM YEAR

Program Year	n Prj	Avg kW	Avg kWh	RTE	CF	CF (SGIP)	Cycles
2017	141	7	18	83%	4%	7%	136
2018	294	7	16	82%	4%	6%	134
2019	380	8	20	84%	4%	7%	145
2020	1236	9	22	85%	4%	7%	134
2021	204	8	21	83%	4%	7%	92
2022	10	8	22	85%	4%	6%	98
Overall	**2265**	**8**	**21**	**84%**	**4%**	**7%**	**132**

C.1.2 Generation Performance Metrics

Capacity Factor

FIGURE C-24: 2021 OBSERVED WEIGHTED AVERAGE CAPACITY FACTOR BY GENERATION TECHNOLOGY

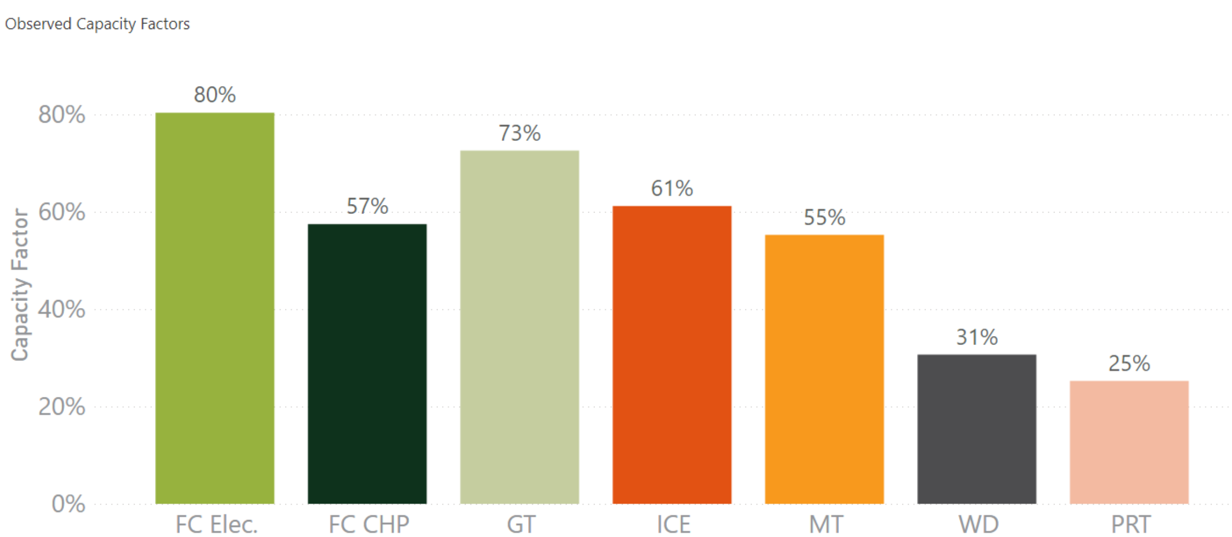


FIGURE C-25: DISTRIBUTION OF OBSERVED 2021 CAPACITY FACTORS BY GENERATION TECHNOLOGY AND INCENTIVE

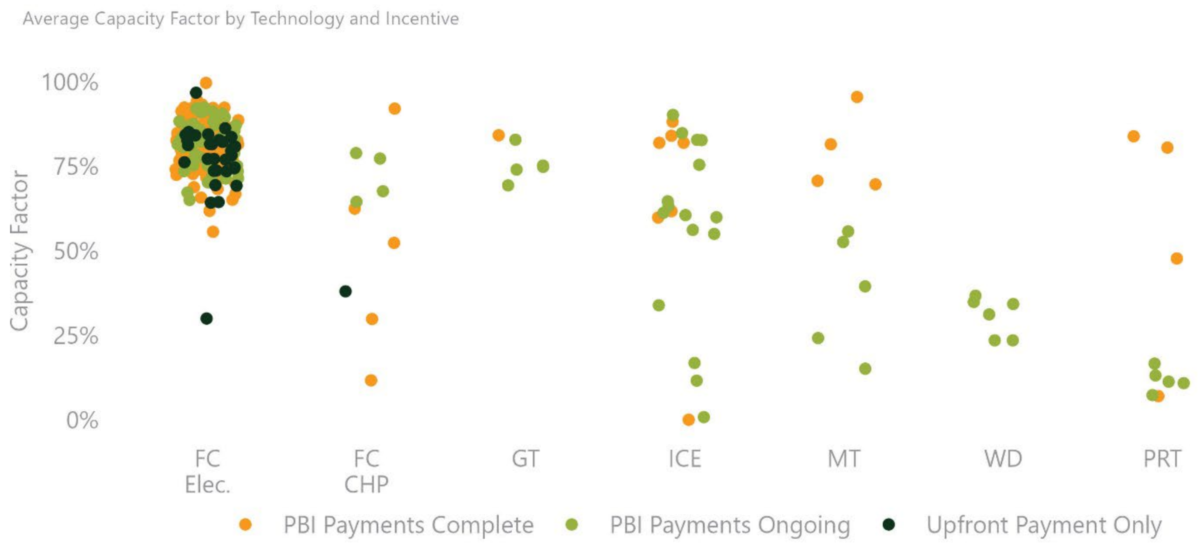


FIGURE C-26: AVERAGE 2021 GENERATION PROFILES BY EQUIPMENT TYPE AND SEASON

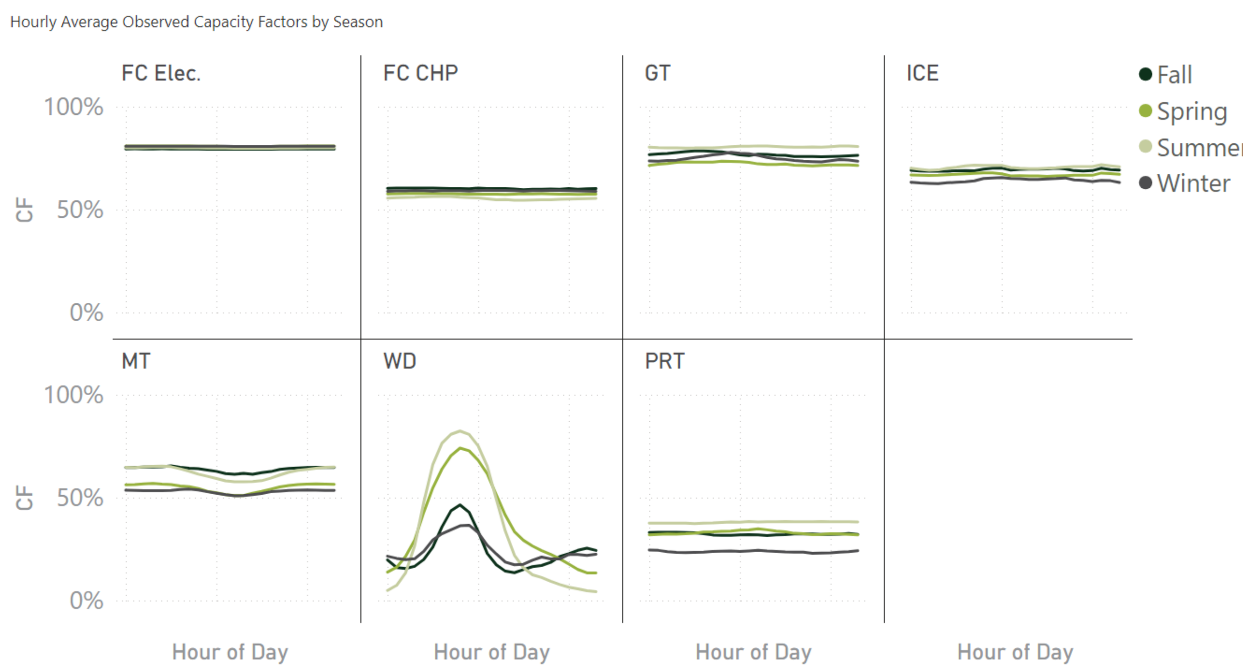
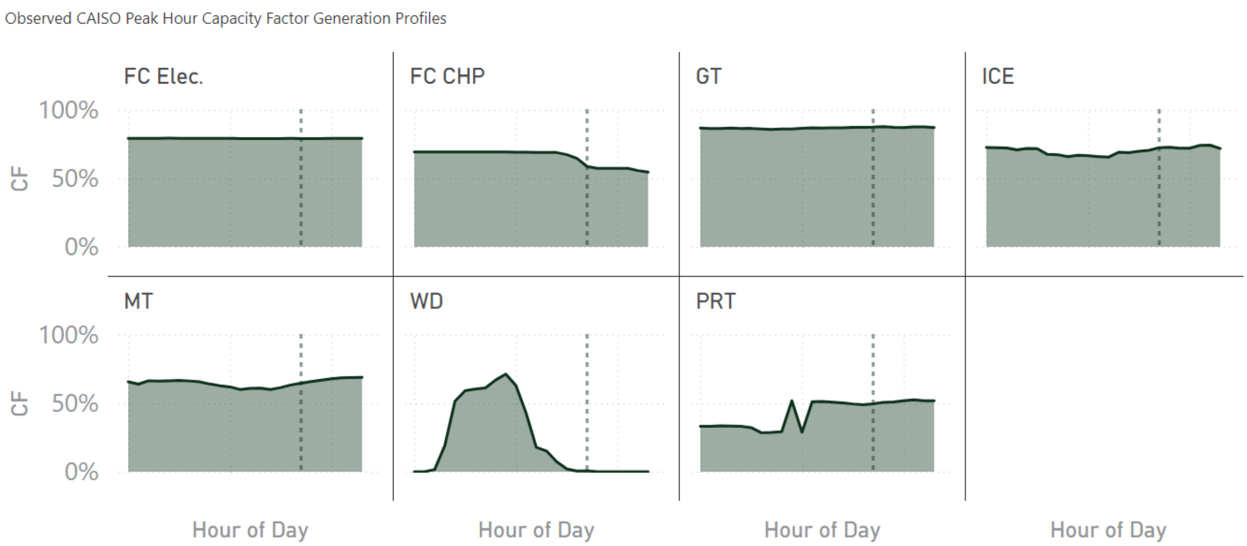


FIGURE C-27: 2021 OBSERVED CAISO PEAK DAY GENERATION PROFILES BY EQUIPMENT TYPE



Electrical, Thermal, and System Efficiency

FIGURE C-28: 2021 OBSERVED WEIGHTED AVERAGE ELECTRICAL, THERMAL, AND SYSTEM EFFICIENCIES BY TECHNOLOGY TYPE

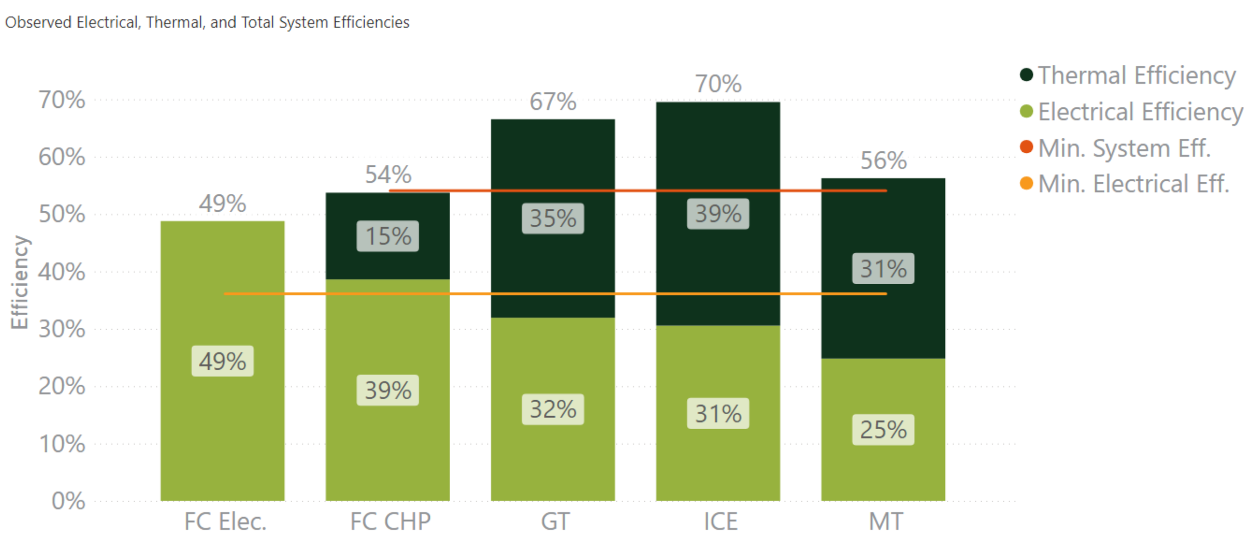


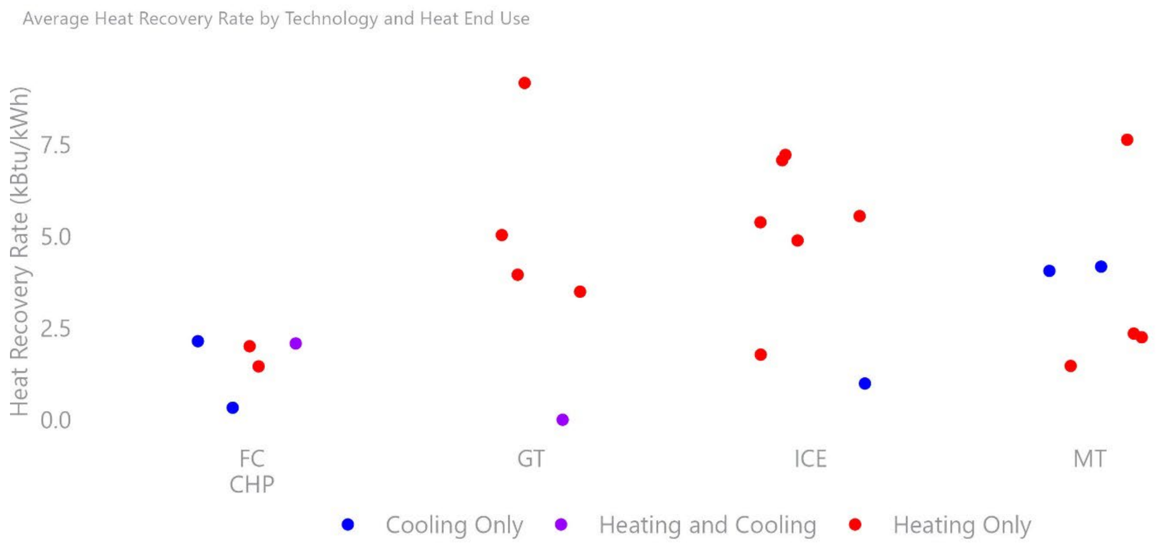
FIGURE C-29: DISTRIBUTION OF OBSERVED 2021 ELECTRICAL EFFICIENCIES BY GENERATION TECHNOLOGY AND INCENTIVE

Useful Heat Recovery

TABLE C-1: END USES SERVED BY USEFUL RECOVERED HEAT

End Use	Project Count	Rated Capacity [MW]	Percent of Rebated Capacity
Cooling Only	9	13	7%
Heating and Cooling	12	16	9%
Heating Only	112	150	84%

FIGURE C-30: DISTRIBUTION OF OBSERVED 2021 HEAT RECOVERY RATES BY GENERATION TECHNOLOGY AND END USE SERVED



Performance Summaries

FIGURE C-31: SUMMARY OF 2021 GENERATION PERFORMANCE METRICS BY EQUIPMENT TYPE

Observed Generation Performance Metrics

Equipment Type	Project Count	Rated Capacity [MW]	Avg. Electrical Generation [GWh]	Capacity Factor	Electrical Efficiency	System Efficiency
FC Elec.	209	68.18	1.86	80%	49%	
FC CHP	10	9.28	4.20	57%	39%	49%
GT	6	84.91	87.56	73%	32%	66%
ICE	25	28.29	5.27	61%	31%	70%
MT	9	5.72	2.03	55%	25%	58%
WD	6	9.07	4.24	31%		
PRT	9	3.02	1.01	25%		
WHP	0	0.00				
Total	**274**	**208.48**	**4.16**	**74%**	**46%**	**61%**

C.2 CUSTOMER IMPACTS

C.2.1 Energy Storage

Storage Dispatch Behavior

FIGURE C-32: PERCENT DAILY RESIDENTIAL DISCHARGE KWH (2021)

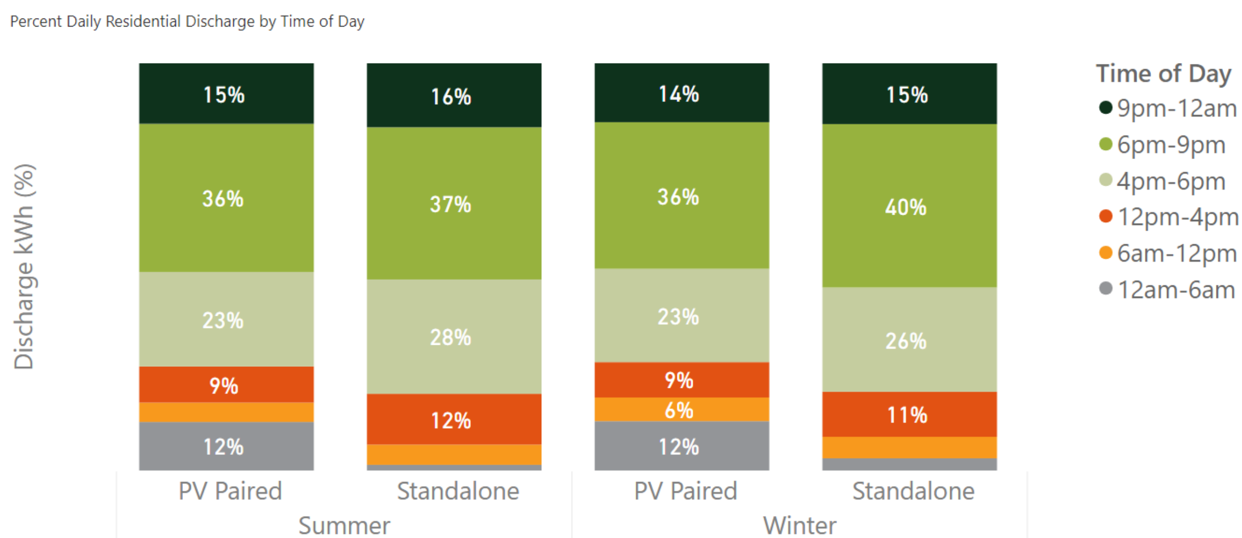


FIGURE C-33: PERCENT DAILY NONRESIDENTIAL DISCHARGE KWH (2021)

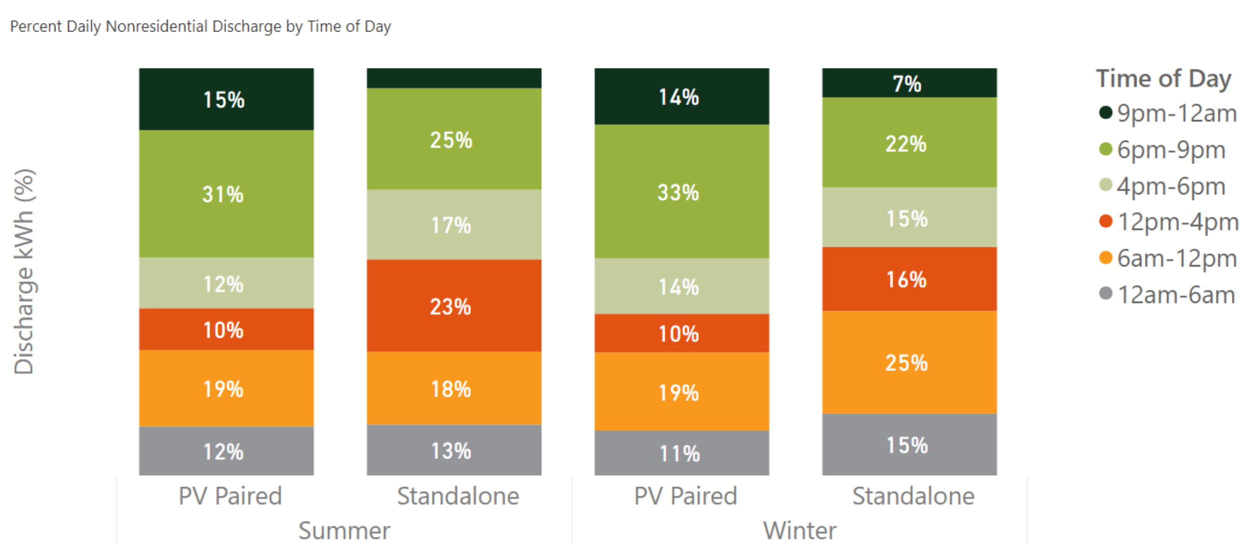


FIGURE C-34: PERCENT DAILY RESIDENTIAL CHARGE KWH (2021)

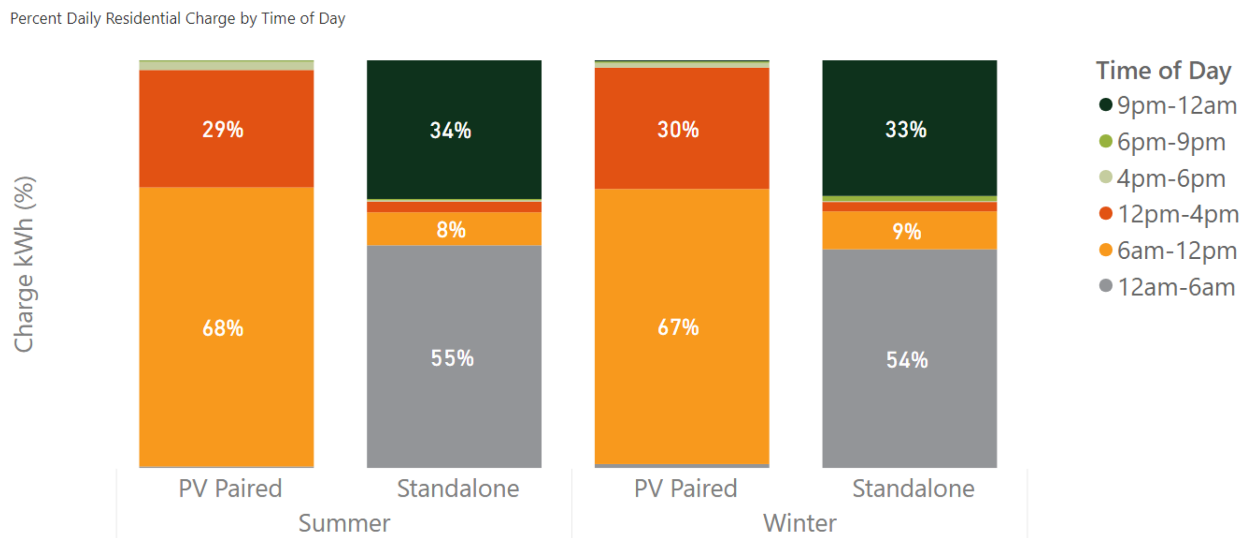


FIGURE C-35: PERCENT DAILY NONRESIDENTIAL CHARGE KWH (2021)

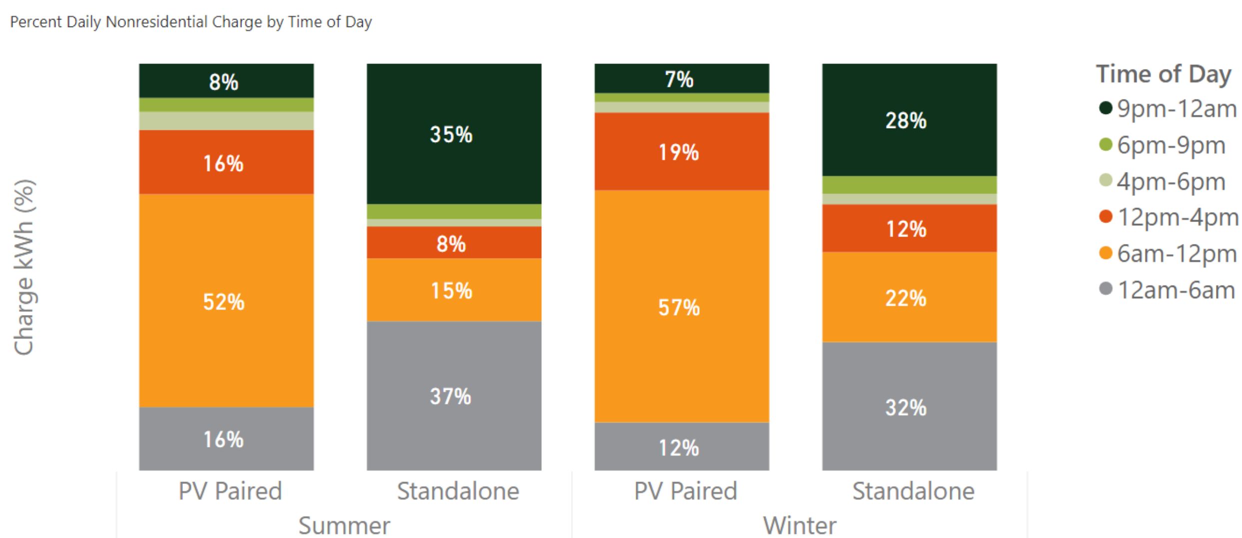


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FIGURE C-36: RESIDENTIAL DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY (2021)

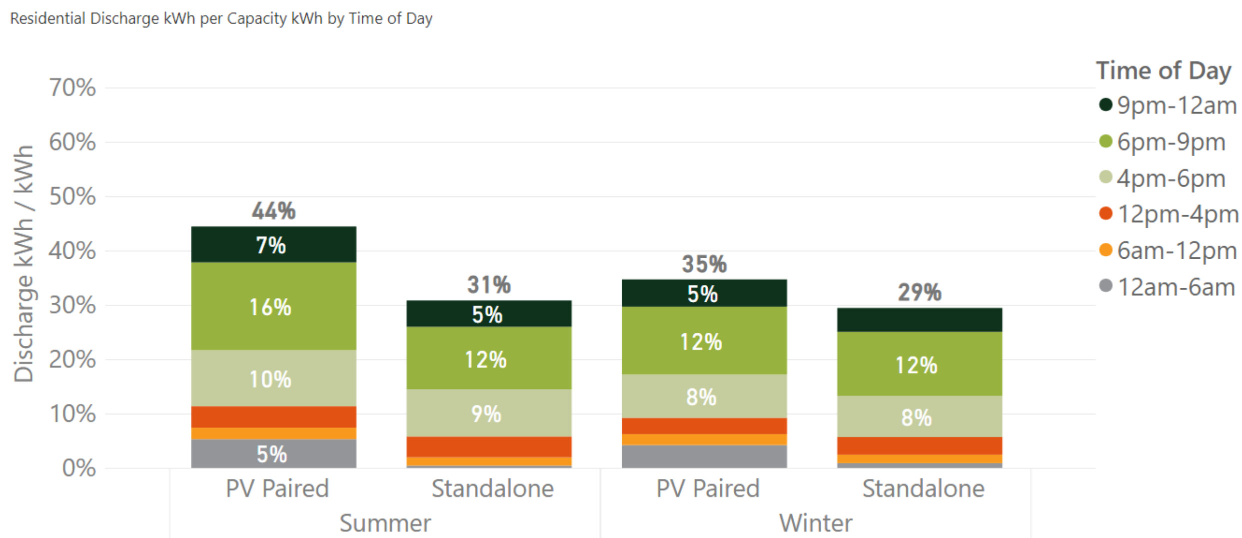

FIGURE C-37: NONRESIDENTIAL DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY (2021)

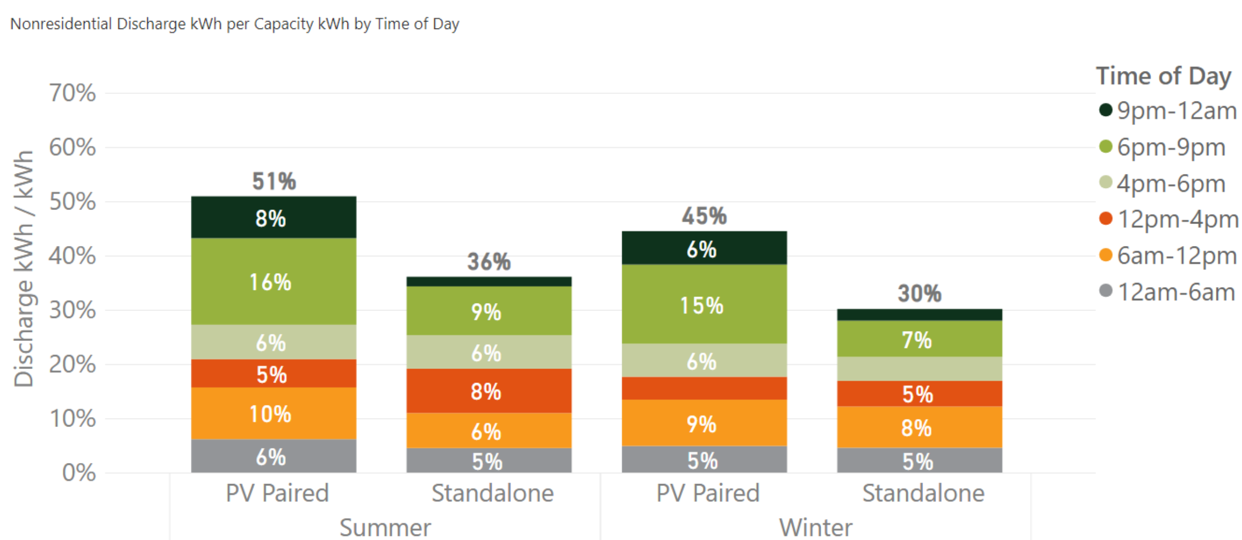

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FIGURE C-38: RESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY (2021)

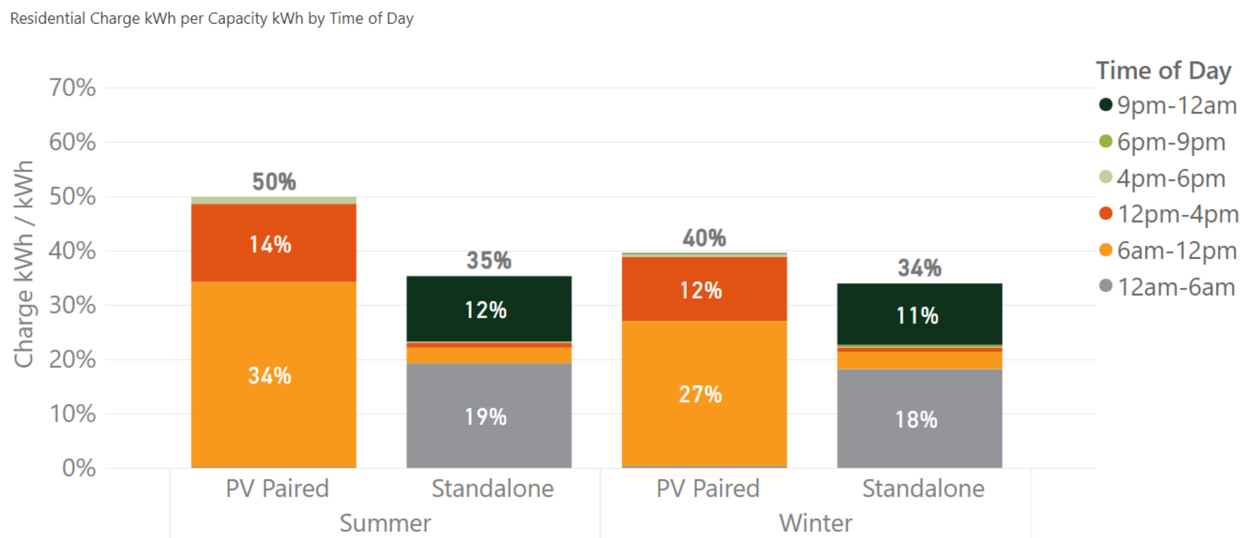


FIGURE C-39: NONRESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY (2021)

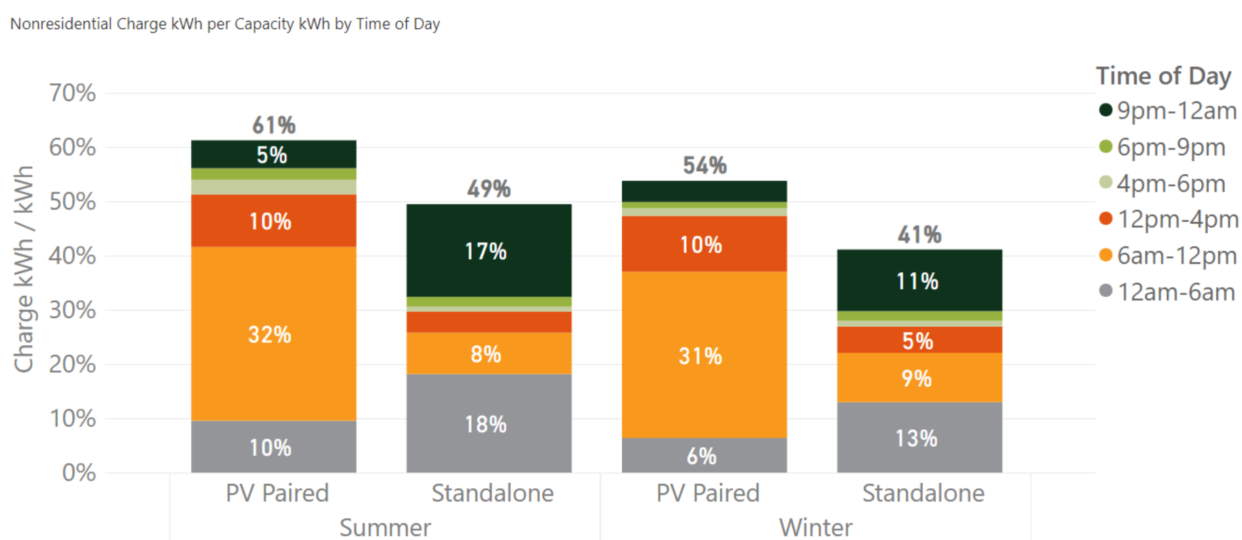


FIGURE C-40: DAILY NET DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND EQUIPMENT (2021)

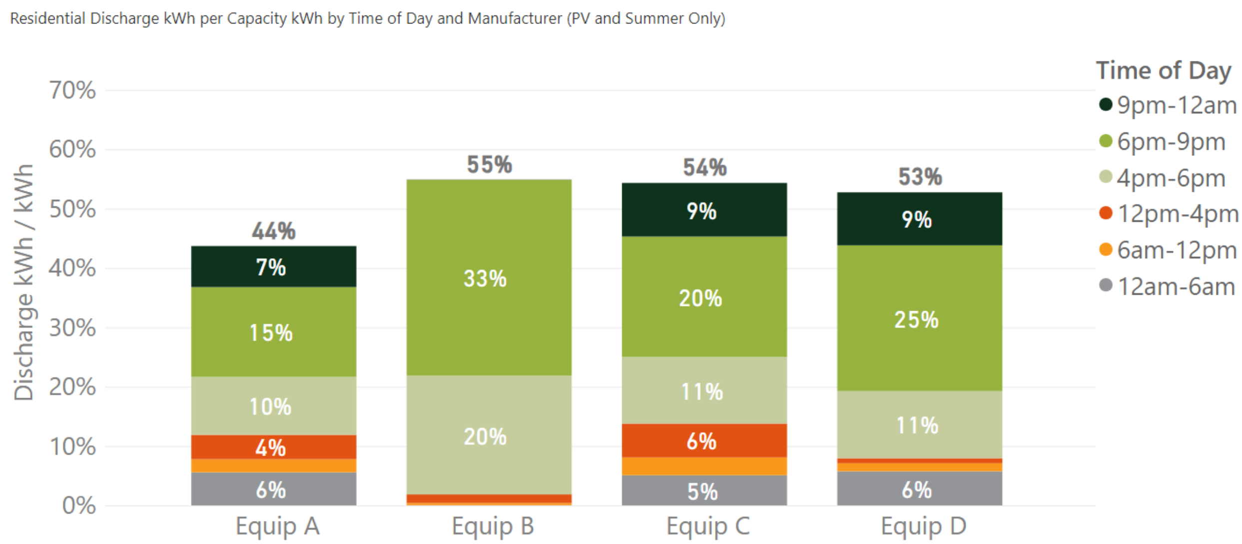


FIGURE C-41: DAILY NET DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND OPERATING MODE (2021)

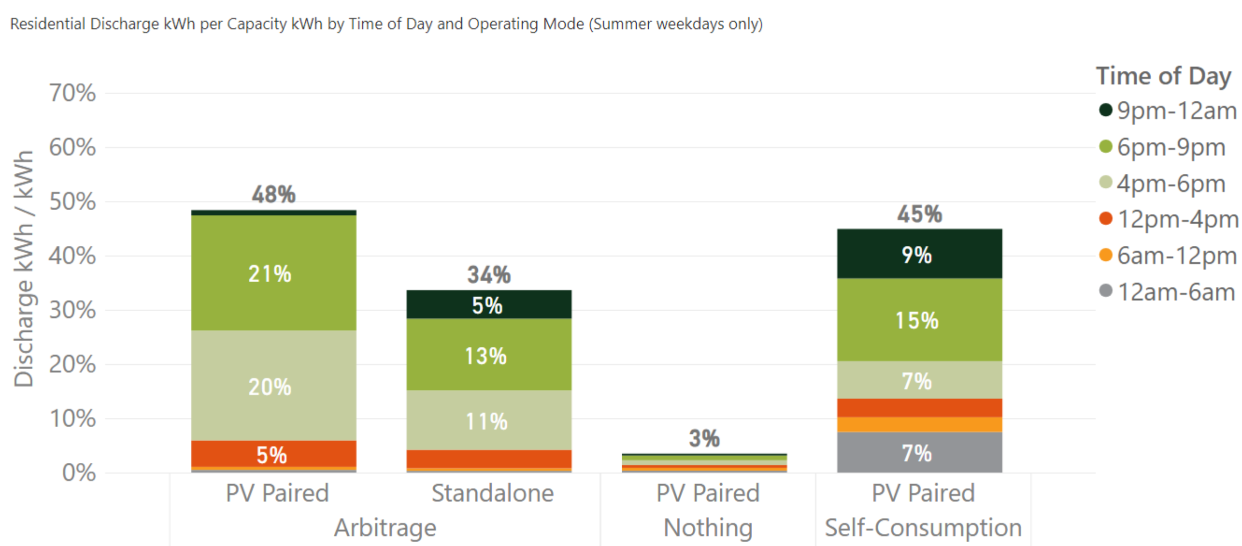


FIGURE C-42: AVERAGE HOURLY DISCHARGE (KWH) / CAPACITY (KWH) PV PAIRED RESIDENTIAL SYSTEMS (2021)

Discharge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	4%	5%	4%	3%	1%	1%	1%
February	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	4%	6%	5%	4%	2%	2%	1%
March	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	3%	4%	5%	5%	4%	3%	2%	2%
April	2%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	2%	3%	5%	5%	4%	3%	3%	2%
May	2%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	3%	3%	5%	5%	5%	3%	3%	2%
June	2%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	6%	6%	5%	3%	3%	2%
July	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	7%	6%	5%	3%	3%	2%
August	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	2%	5%	6%	7%	6%	5%	3%	2%	2%
September	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	6%	7%	6%	4%	3%	2%	1%
October	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%	1%	3%	5%	6%	5%	4%	3%	2%	2%
November	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	5%	4%	3%	2%	1%	1%
December	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	5%	3%	2%	1%	1%	1%

FIGURE C-43: AVERAGE HOURLY CHARGE (KWH) / CAPACITY (KWH) PV PAIRED RESIDENTIAL SYSTEMS (2021)

Charge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	0%	0%	0%	3%	5%	7%	7%	5%	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
February	0%	0%	0%	0%	0%	0%	0%	1%	4%	7%	9%	8%	6%	4%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
March	0%	0%	0%	0%	0%	0%	0%	1%	4%	8%	9%	8%	6%	4%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
April	0%	0%	0%	0%	0%	0%	0%	1%	5%	8%	10%	8%	6%	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
May	0%	0%	0%	0%	0%	0%	0%	2%	5%	9%	10%	8%	5%	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
June	0%	0%	0%	0%	0%	0%	0%	2%	6%	9%	10%	9%	6%	3%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%
July	0%	0%	0%	0%	0%	0%	0%	2%	5%	9%	10%	9%	6%	4%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%
August	0%	0%	0%	0%	0%	0%	0%	1%	4%	8%	10%	10%	7%	4%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%
September	0%	0%	0%	0%	0%	0%	0%	1%	3%	7%	10%	10%	7%	5%	3%	1%	1%	0%	0%	0%	0%	0%	0%	0%
October	0%	0%	0%	0%	0%	0%	0%	0%	3%	6%	8%	8%	6%	4%	3%	1%	0%	0%	0%	0%	0%	0%	0%	0%
November	0%	0%	0%	0%	0%	0%	0%	1%	3%	6%	8%	7%	5%	4%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
December	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	5%	4%	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%

FIGURE C-44: AVERAGE HOURLY DISCHARGE (KWH) / CAPACITY (KWH) STANDALONE RESIDENTIAL SYSTEMS (2021)

Discharge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	4%	6%	6%	5%	4%	2%	1%	1%
February	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	4%	3%	2%	1%	1%
March	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	4%	4%	5%	4%	2%	1%	1%
April	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	4%	5%	4%	2%	1%	1%
May	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	4%	4%	4%	3%	1%	1%
June	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	1%	1%	2%	4%	4%	4%	4%	4%	3%	2%	1%
July	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	5%	4%	4%	4%	4%	2%	2%	1%
August	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	2%	5%	5%	4%	4%	4%	2%	2%	1%
September	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	4%	4%	4%	4%	2%	2%	1%
October	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	3%	4%	4%	3%	2%	2%	1%
November	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	4%	4%	3%	2%	1%	1%
December	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	5%	5%	4%	4%	3%	2%	1%	1%

FIGURE C-45: AVERAGE HOURLY CHARGE (KWH) / CAPACITY (KWH) STANDALONE RESIDENTIAL SYSTEMS (2021)

Charge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	6%	7%	4%	3%	1%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	4%	2%	3%
February	8%	6%	3%	2%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	2%	4%
March	9%	5%	3%	1%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	5%	3%	4%
April	9%	5%	3%	1%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%	3%	5%
May	9%	5%	3%	1%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	2%	5%
June	11%	7%	3%	1%	0%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	5%
July	10%	6%	3%	1%	0%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	4%	3%	5%
August	10%	5%	2%	1%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%	4%	6%
September	11%	5%	1%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	6%
October	10%	5%	2%	1%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	2%	5%
November	10%	4%	2%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%	3%	5%
December	10%	5%	2%	1%	0%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	4%	4%	5%

FIGURE C-46: AVERAGE HOURLY DISCHARGE (KWH) / CAPACITY (KWH) PV PAIRED NONRESIDENTIAL SYSTEMS (2021)

Discharge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	1%	1%	1%	1%	1%	1%	3%	3%	2%	1%	0%	0%	1%	1%	1%	1%	2%	4%	4%	4%	4%	3%	1%	2%
February	1%	1%	1%	1%	1%	2%	4%	3%	1%	1%	0%	0%	0%	0%	1%	1%	2%	4%	5%	5%	4%	3%	1%	2%
March	1%	1%	1%	1%	1%	2%	4%	3%	1%	1%	1%	0%	0%	0%	1%	1%	1%	2%	4%	6%	5%	3%	1%	2%
April	1%	1%	1%	1%	1%	2%	4%	3%	1%	0%	0%	0%	0%	0%	1%	1%	2%	2%	3%	6%	6%	3%	1%	2%
May	1%	1%	1%	1%	1%	2%	3%	2%	1%	1%	0%	0%	0%	0%	1%	1%	2%	3%	4%	7%	7%	4%	2%	2%
June	1%	1%	1%	1%	1%	2%	4%	2%	1%	1%	0%	0%	1%	1%	1%	1%	2%	3%	3%	6%	6%	4%	2%	2%
July	1%	1%	1%	1%	1%	2%	4%	2%	1%	1%	0%	1%	1%	1%	1%	1%	3%	3%	4%	6%	6%	4%	2%	2%
August	1%	1%	1%	1%	1%	2%	3%	3%	2%	1%	1%	1%	1%	2%	2%	1%	3%	4%	4%	6%	6%	4%	2%	2%
September	0%	0%	1%	1%	1%	1%	3%	3%	2%	1%	1%	1%	2%	3%	1%	2%	3%	5%	5%	6%	5%	3%	2%	2%
October	1%	0%	1%	1%	0%	1%	2%	3%	2%	1%	1%	1%	2%	3%	1%	2%	3%	6%	6%	6%	5%	3%	1%	2%
November	0%	0%	1%	1%	0%	1%	2%	2%	1%	0%	0%	0%	2%	3%	1%	2%	3%	5%	5%	5%	5%	3%	1%	2%
December	0%	0%	0%	1%	0%	1%	2%	2%	1%	1%	0%	0%	2%	2%	1%	1%	3%	5%	4%	5%	4%	2%	1%	2%

FIGURE C-47: AVERAGE HOURLY CHARGE (KWH) / CAPACITY (KWH) PV PAIRED NONRESIDENTIAL SYSTEMS (2021)

Charge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	2%	2%	1%	2%	1%	1%	1%	1%	5%	8%	8%	6%	4%	3%	2%	1%	0%	0%	0%	0%	1%	2%	2%	2%
February	1%	1%	1%	1%	1%	1%	0%	2%	7%	8%	7%	6%	4%	2%	1%	1%	1%	0%	0%	0%	0%	1%	2%	1%
March	1%	1%	1%	1%	1%	0%	1%	2%	7%	9%	7%	5%	3%	2%	2%	1%	1%	1%	0%	0%	0%	1%	1%	1%
April	1%	1%	1%	1%	1%	0%	0%	2%	6%	8%	7%	6%	4%	3%	2%	1%	1%	1%	1%	0%	0%	1%	1%	1%
May	1%	1%	1%	1%	1%	0%	1%	3%	6%	8%	8%	7%	4%	2%	1%	1%	1%	1%	1%	0%	0%	1%	1%	1%
June	2%	2%	1%	1%	1%	1%	1%	4%	7%	8%	8%	6%	3%	2%	1%	1%	1%	1%	1%	0%	0%	1%	2%	2%
July	2%	2%	1%	1%	1%	1%	1%	4%	7%	9%	8%	6%	3%	2%	1%	1%	1%	1%	1%	0%	0%	1%	2%	2%
August	2%	2%	2%	2%	1%	1%	1%	3%	5%	7%	8%	6%	4%	2%	2%	2%	2%	2%	1%	1%	1%	2%	2%	2%
September	2%	2%	2%	2%	2%	1%	1%	2%	5%	7%	8%	7%	4%	3%	3%	2%	2%	1%	1%	0%	1%	2%	2%	2%
October	2%	2%	2%	1%	1%	1%	1%	1%	5%	8%	8%	7%	5%	3%	3%	2%	2%	1%	1%	0%	1%	1%	2%	2%
November	1%	1%	1%	1%	1%	0%	0%	2%	6%	8%	9%	7%	4%	2%	3%	1%	1%	0%	0%	0%	0%	1%	1%	1%
December	1%	1%	1%	1%	1%	1%	0%	1%	4%	7%	8%	7%	4%	3%	3%	1%	0%	0%	0%	0%	1%	1%	1%	1%

FIGURE C-48: AVERAGE HOURLY DISCHARGE (KWH) / CAPACITY (KWH) STANDALONE NONRESIDENTIAL SYSTEMS (2021)

Discharge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	1%	1%	1%	1%	1%	1%	2%	2%	1%	2%	2%	2%	2%	3%	1%	1%	2%	2%	3%	3%	3%	1%	1%	1%
February	1%	1%	1%	1%	1%	1%	2%	2%	1%	2%	3%	3%	2%	2%	1%	1%	2%	3%	3%	3%	2%	1%	1%	1%
March	1%	1%	1%	1%	1%	1%	2%	2%	1%	1%	2%	2%	2%	3%	1%	1%	2%	2%	2%	2%	2%	1%	1%	1%
April	1%	1%	1%	1%	1%	2%	2%	2%	1%	1%	2%	2%	2%	3%	1%	1%	2%	2%	2%	2%	2%	1%	1%	1%
May	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	1%	1%	1%	3%	1%	1%	3%	2%	2%	3%	3%	1%	1%	1%
June	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	5%	3%	2%	6%	4%	3%	3%	3%	1%	1%	1%
July	0%	1%	1%	1%	1%	1%	2%	1%	1%	2%	2%	1%	1%	4%	2%	1%	5%	4%	3%	4%	4%	1%	1%	0%
August	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	5%	2%	1%	4%	3%	3%	3%	3%	1%	0%	1%
September	1%	1%	1%	1%	1%	1%	2%	2%	1%	1%	2%	2%	2%	5%	2%	1%	4%	3%	3%	3%	3%	1%	1%	1%
October	1%	1%	1%	1%	1%	1%	2%	3%	1%	1%	1%	2%	2%	3%	1%	1%	2%	3%	2%	2%	2%	1%	1%	1%
November	0%	0%	0%	0%	1%	1%	2%	2%	1%	1%	2%	1%	2%	2%	1%	1%	2%	2%	2%	2%	2%	1%	0%	1%
December	0%	0%	0%	0%	0%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	0%	2%	2%	2%	2%	2%	1%	0%	1%

FIGURE C-49: AVERAGE HOURLY CHARGE (KWH) / CAPACITY (KWH) STANDALONE NONRESIDENTIAL SYSTEMS (2021)

Charge	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	4%	4%	4%	4%	3%	3%	2%	2%	3%	3%	2%	3%	2%	2%	2%	4%	2%	2%	2%	1%	2%	8%	6%	4%
February	5%	4%	4%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	4%	3%	2%	2%	1%	2%	9%	7%	4%
March	4%	3%	3%	3%	3%	3%	2%	2%	2%	3%	2%	3%	3%	3%	2%	2%	2%	2%	2%	1%	1%	5%	5%	4%
April	4%	4%	3%	3%	2%	2%	2%	2%	3%	3%	3%	3%	3%	3%	3%	3%	2%	1%	2%	1%	1%	7%	5%	4%
May	3%	3%	3%	3%	3%	3%	2%	2%	3%	3%	2%	3%	2%	2%	2%	2%	1%	2%	1%	1%	1%	6%	4%	3%
June	6%	5%	4%	4%	4%	3%	2%	2%	2%	2%	2%	2%	3%	3%	1%	2%	1%	1%	2%	3%	3%	8%	7%	9%
July	6%	5%	5%	4%	4%	3%	2%	2%	2%	2%	2%	2%	3%	2%	1%	2%	1%	2%	2%	2%	2%	7%	6%	6%
August	6%	5%	4%	4%	3%	3%	2%	2%	2%	2%	2%	2%	2%	3%	2%	3%	1%	3%	4%	3%	1%	7%	6%	7%
September	6%	5%	4%	4%	3%	3%	2%	2%	2%	3%	2%	2%	2%	3%	1%	4%	1%	3%	4%	2%	1%	6%	6%	6%
October	4%	4%	4%	4%	3%	3%	2%	1%	2%	3%	3%	3%	2%	2%	2%	3%	2%	2%	1%	1%	1%	5%	4%	4%
November	4%	3%	3%	3%	2%	2%	2%	1%	3%	2%	2%	2%	2%	3%	3%	3%	1%	1%	1%	1%	1%	4%	3%	3%
December	3%	3%	3%	2%	2%	2%	1%	1%	3%	2%	2%	2%	2%	2%	3%	2%	1%	1%	1%	1%	1%	4%	3%	3%

C.2.2 Generation

Average NCP Customer Demand Impacts

FIGURE C-50: 2021 OBSERVED AVERAGE MONTHLY NCP IMPACTS AS PERCENT OF REBATED CAPACITY

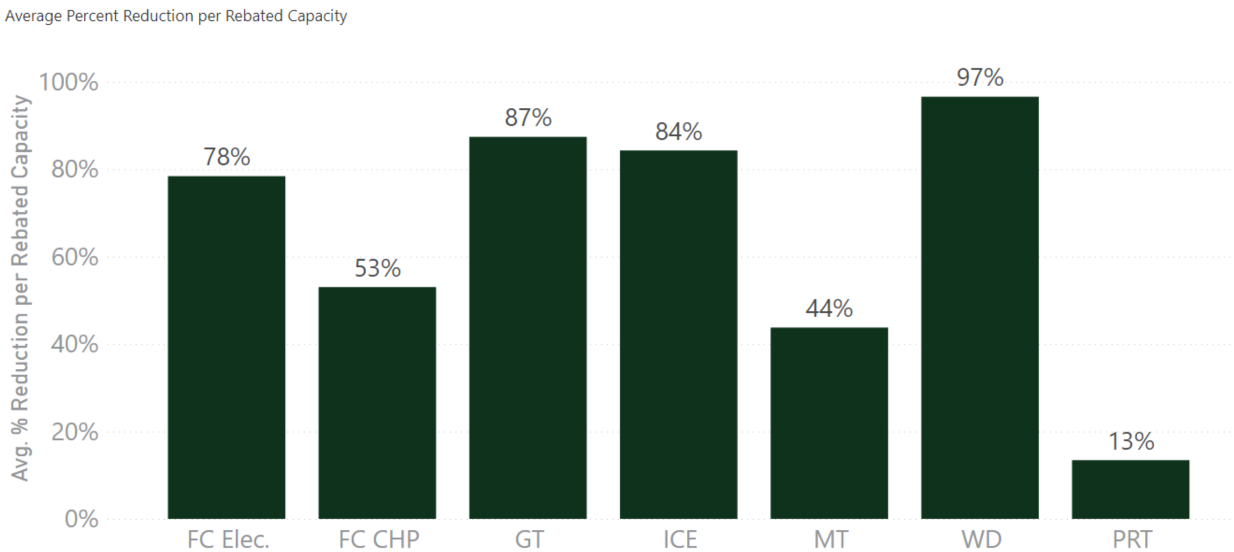
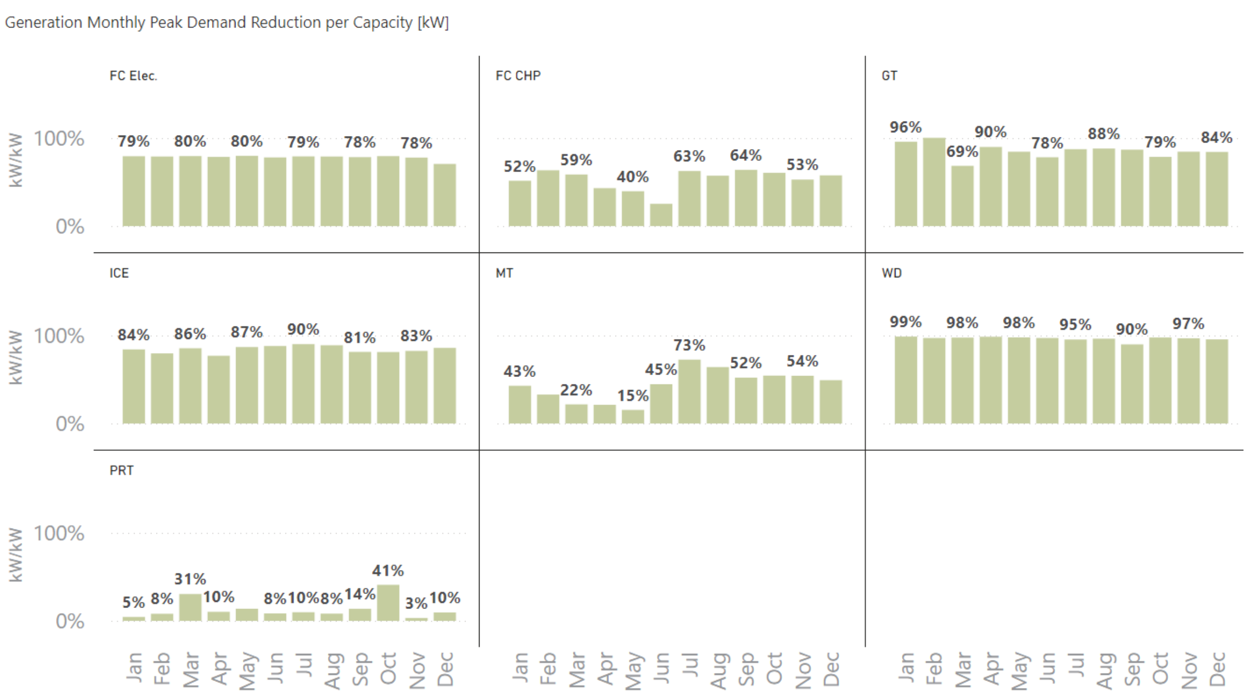


FIGURE C-51: 2021 OBSERVED MONTHLY NCP IMPACTS AS PERCENT OF REBATED CAPACITY



VERDANT

Natural Gas Impacts

FIGURE C-52: 2021 OBSERVED NATURAL GAS IMPACTS

C.3 CAISO AND IOU SYSTEM IMPACTS

TABLE C-2: 2021 CAISO AND IOU PEAK HOURS AND DEMAND (MW)

Peak Period	Peak Demand [MW]	Date	Hour [Local Time]
CAISO - Gross	43,789	September 8th, 2021	5PM – 6PM
CAISO – Net	39,372	September 8th, 2021	6PM - 7PM
PG&E	19,931	June 18th, 2021	6PM - 7PM
SCE	21,283	September 9th, 2021	3PM - 4PM
SDG&E	3,808	August 26th, 2021	5PM – 6PM

FIGURE C-53: 2021 LOAD DISTRIBUTION CURVES

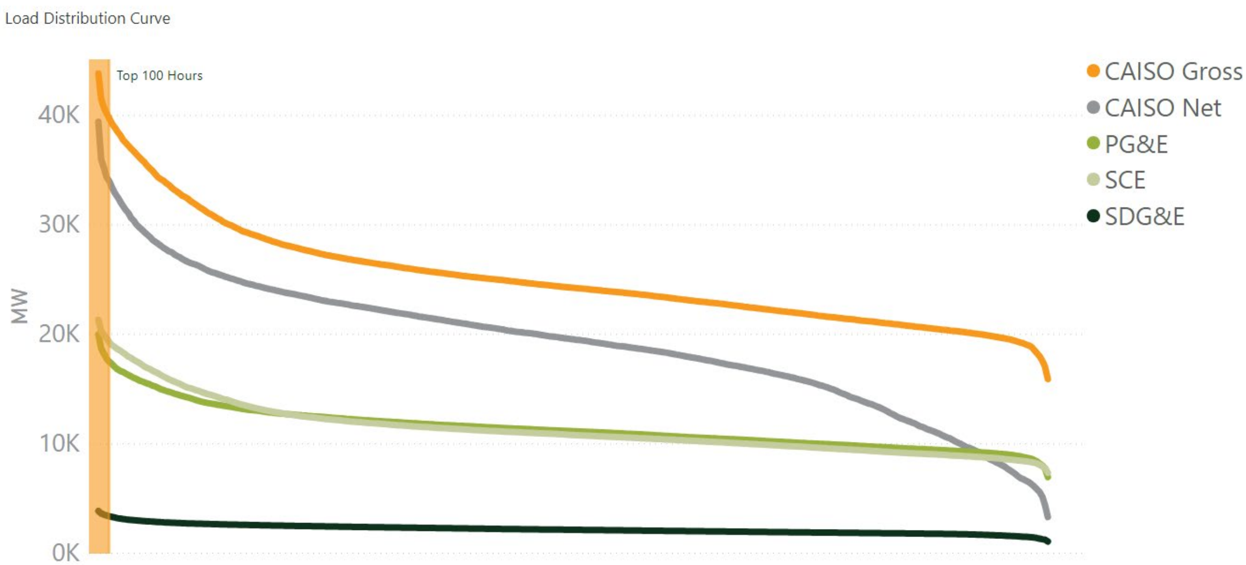


FIGURE C-54: 2021 TOP 100 HOUR DISTRIBUTIONS BY MONTH

Top 100 Hour Distributions by Month

Year	June	July	August	September	December
2021					
CAISO Gross	7	35	36	22	
CAISO Net	9	32	29	30	
PG&E	18	36	28	18	
SCE	4	31	42	23	
SDG&E	3	10	45	39	3

C.3.1 Energy Storage

CAISO System Impacts

FIGURE C-55: HOURLY STORAGE KWH PER KW – 2021 CAISO GROSS LOAD HOURS FOR NONRESIDENTIAL

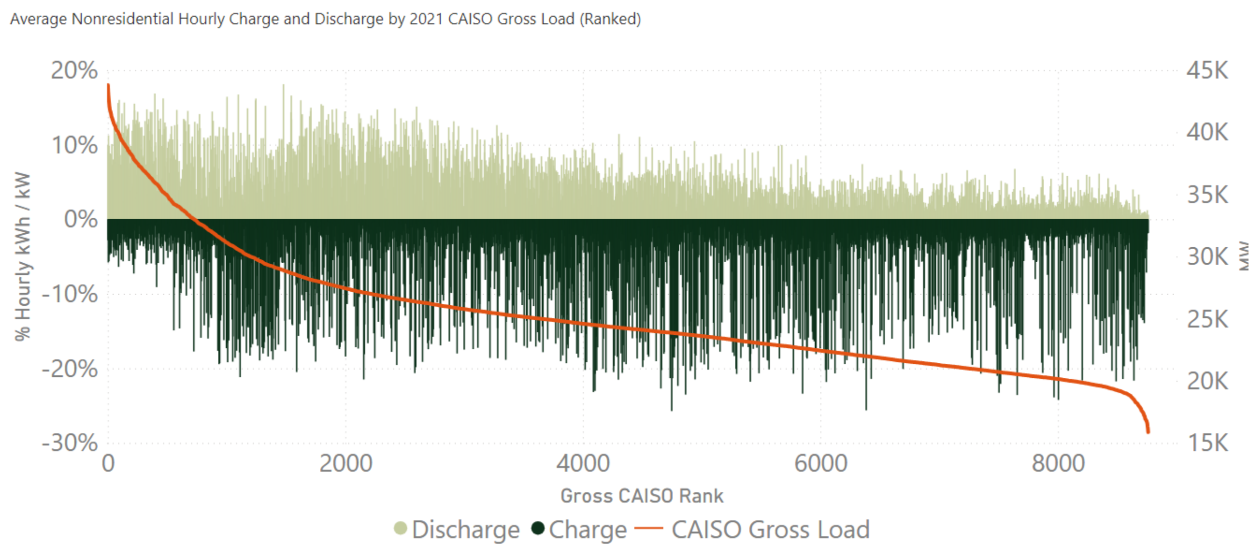


FIGURE C-56: HOURY STORAGE KWH PER KW – 2021 CAISO NET HOURS FOR NONRESIDENTIAL

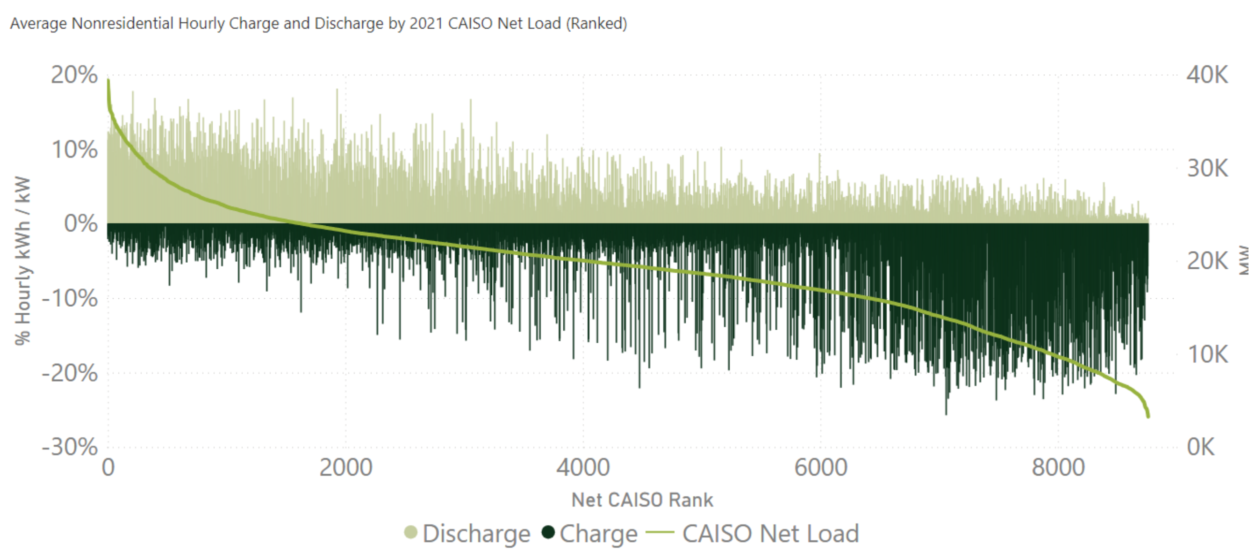


FIGURE C-57: HOURLY STORAGE KWH PER KW – 2021 CAISO GROSS LOAD HOURS FOR RESIDENTIAL

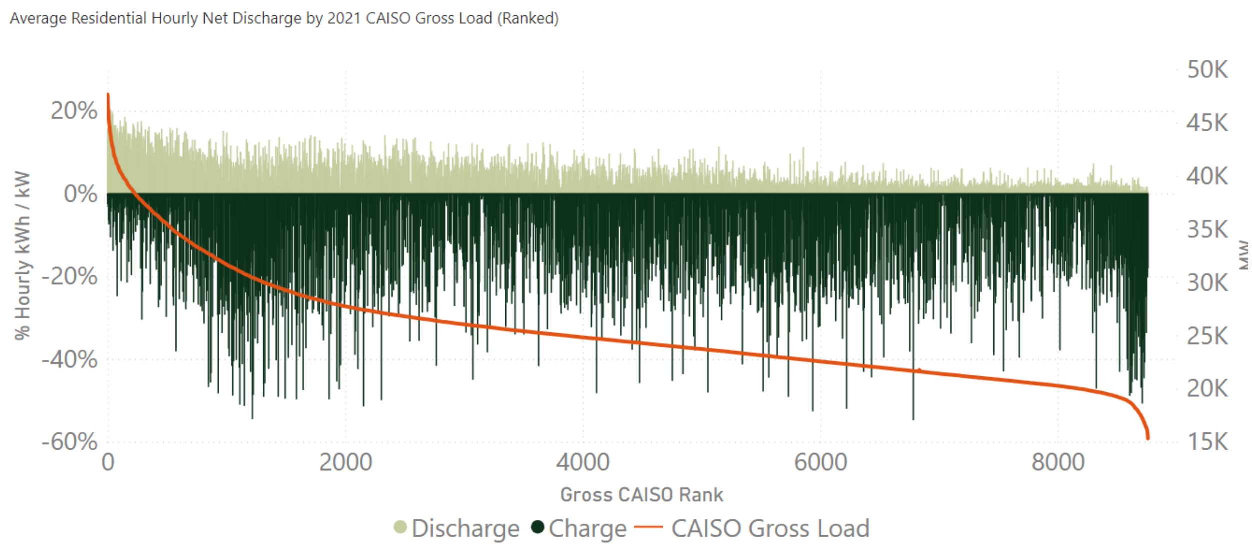


FIGURE C-58: HOURLY STORAGE KWH PER KW – 2021 CAISO NET HOURS FOR RESIDENTIAL

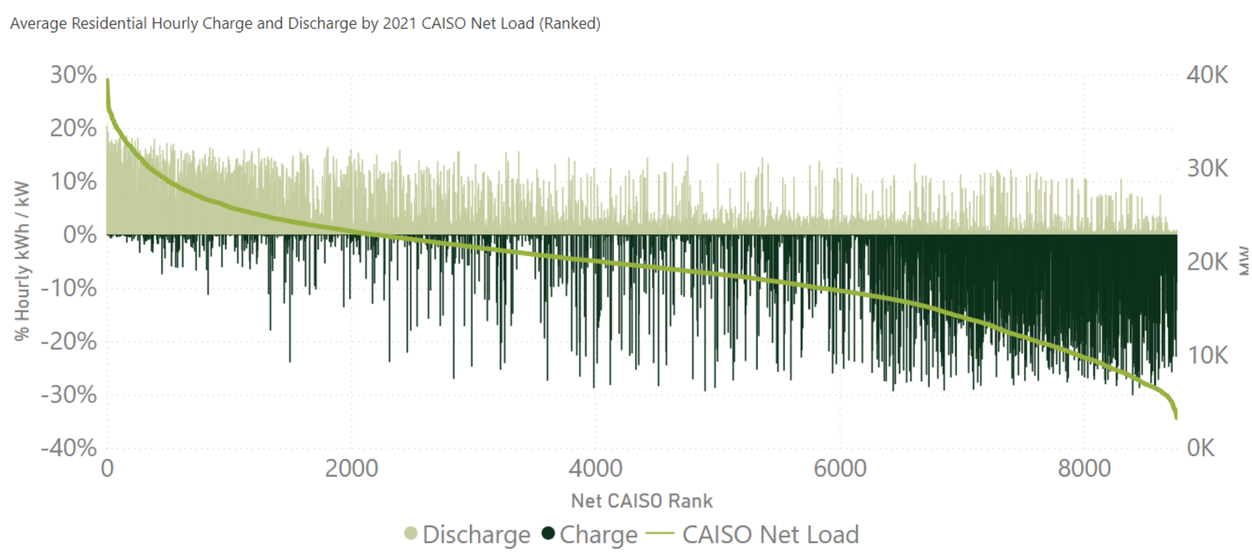


FIGURE C-59: HOURLY STORAGE KWH PER KW – CAISO TOP GROSS 100 HOURS FOR NONRESIDENTIAL (2021)

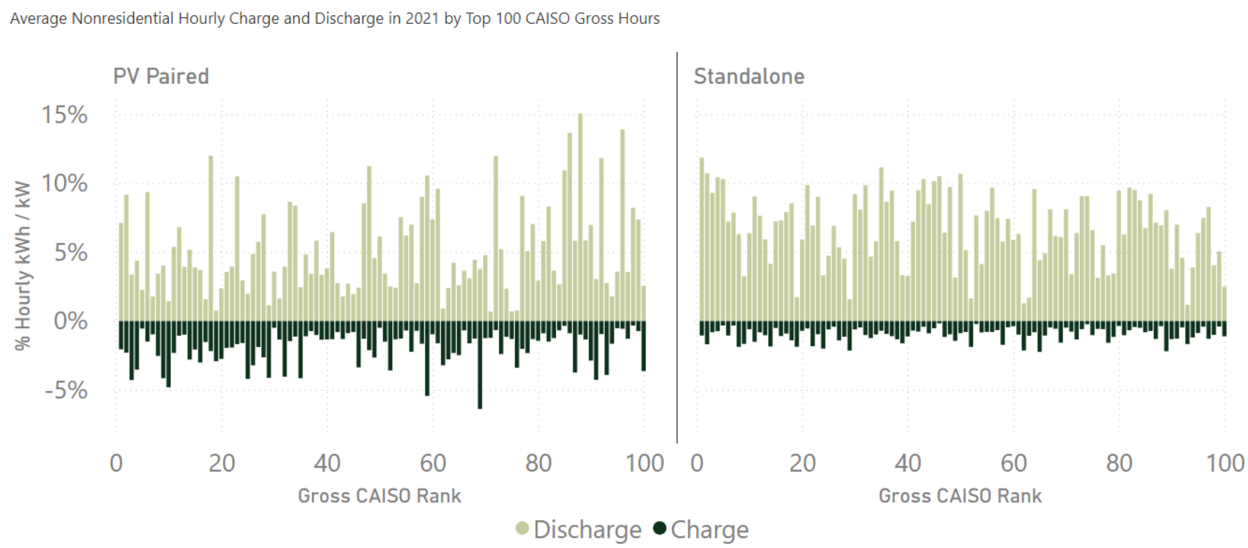


FIGURE C-60: HOURLY STORAGE KWH PER KW – CAISO TOP NET 100 HOURS FOR NONRESIDENTIAL (2021)

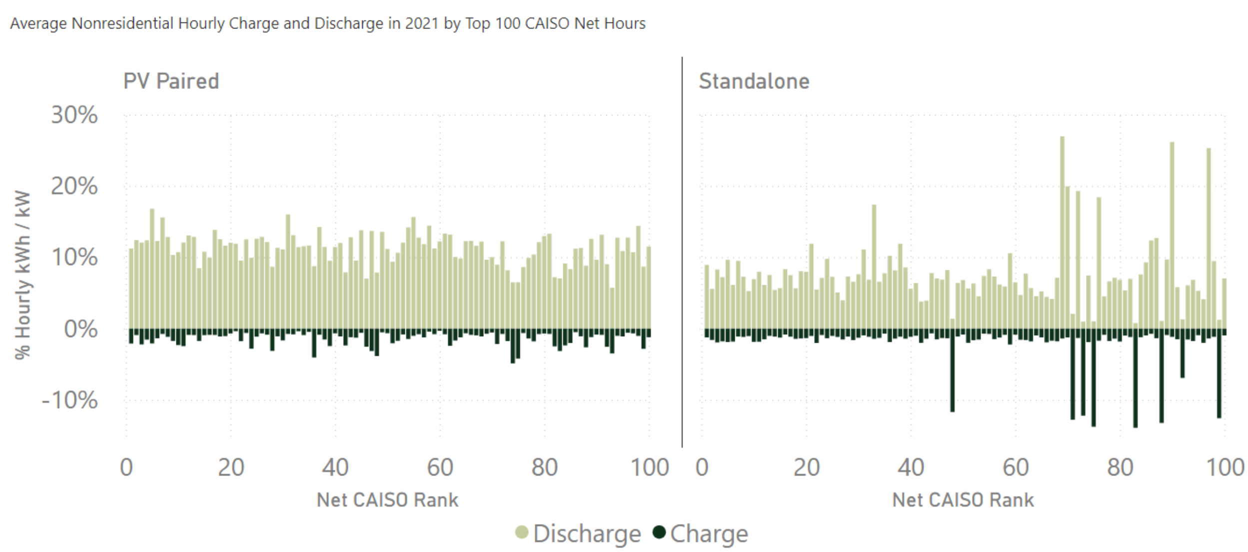


FIGURE C-61: HOURLY STORAGE KWH PER KW – CAISO TOP GROSS 100 HOURS FOR RESIDENTIAL (2021)

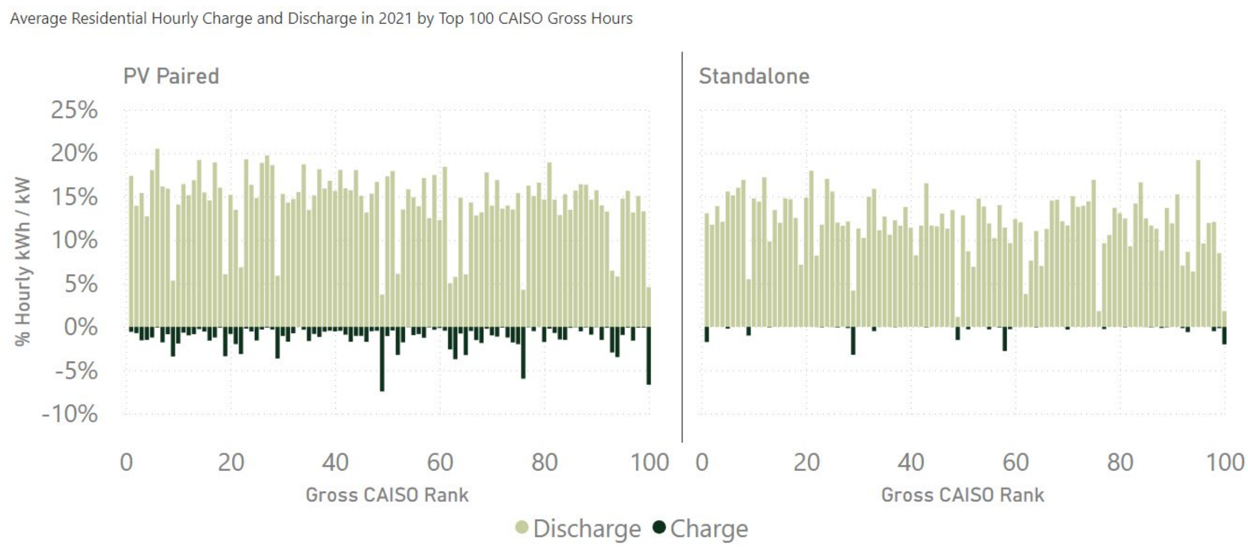
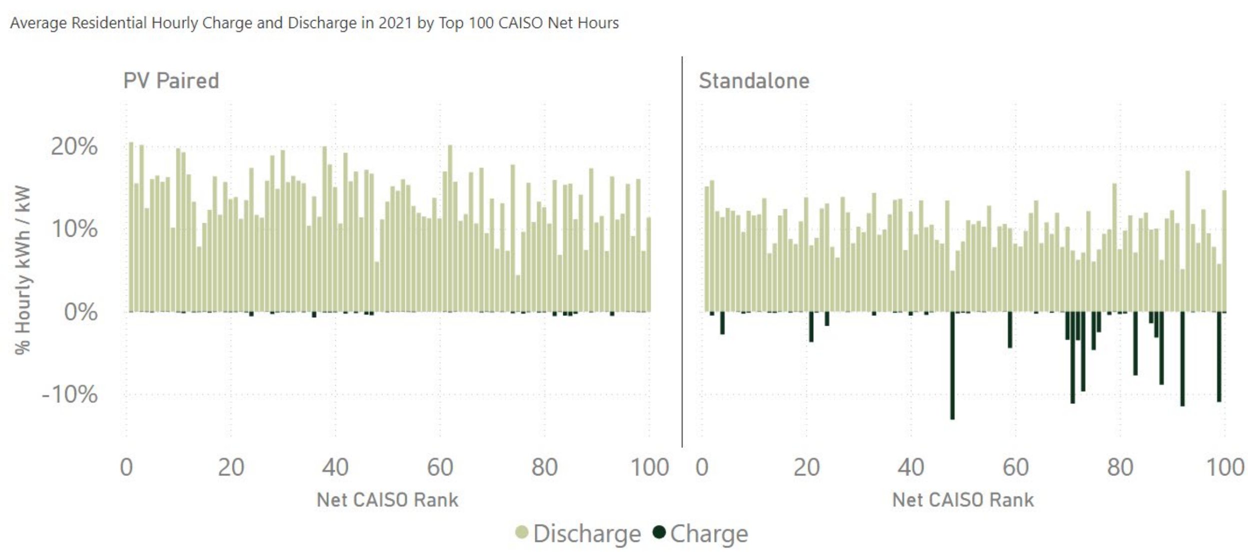


FIGURE C-62: HOURLY STORAGE KWH PER KW – CAISO TOP NET 100 HOURS FOR RESIDENTIAL (2021)



C.3.2 Generation

FIGURE C-63: 2021 OBSERVED CAISO GROSS PEAK DEMAND IMPACT PER REBATED CAPACITY [KW] BY INCENTIVE DESIGN

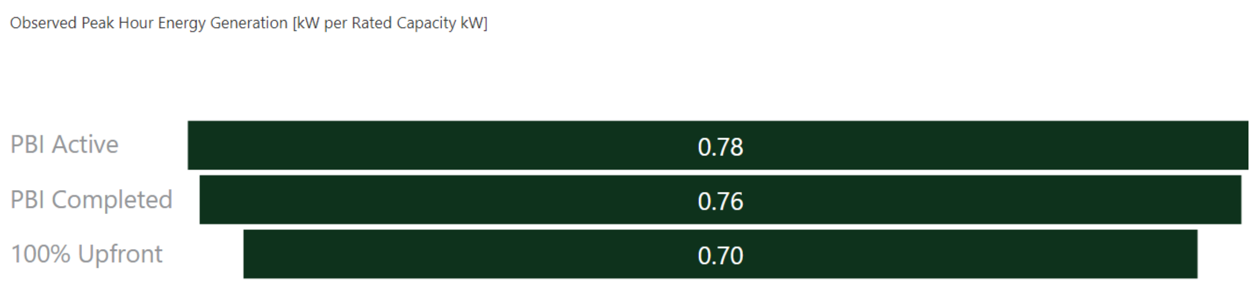


FIGURE C-64: 2021 OBSERVED CAISO GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE (TOTAL)

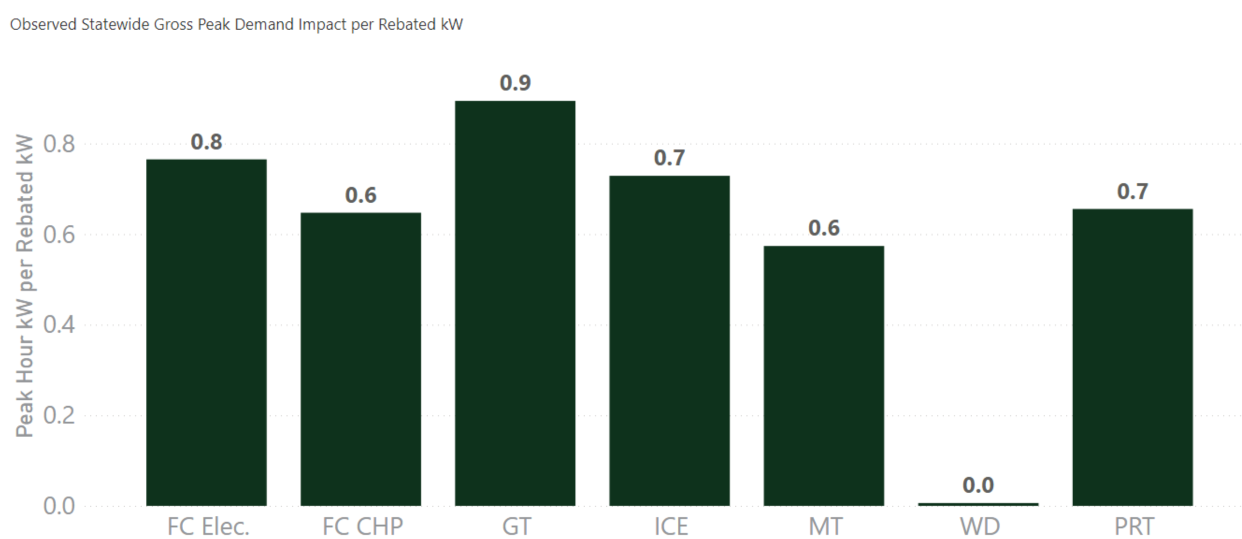


FIGURE C-65: 2021 OBSERVED CAISO GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE AND PA

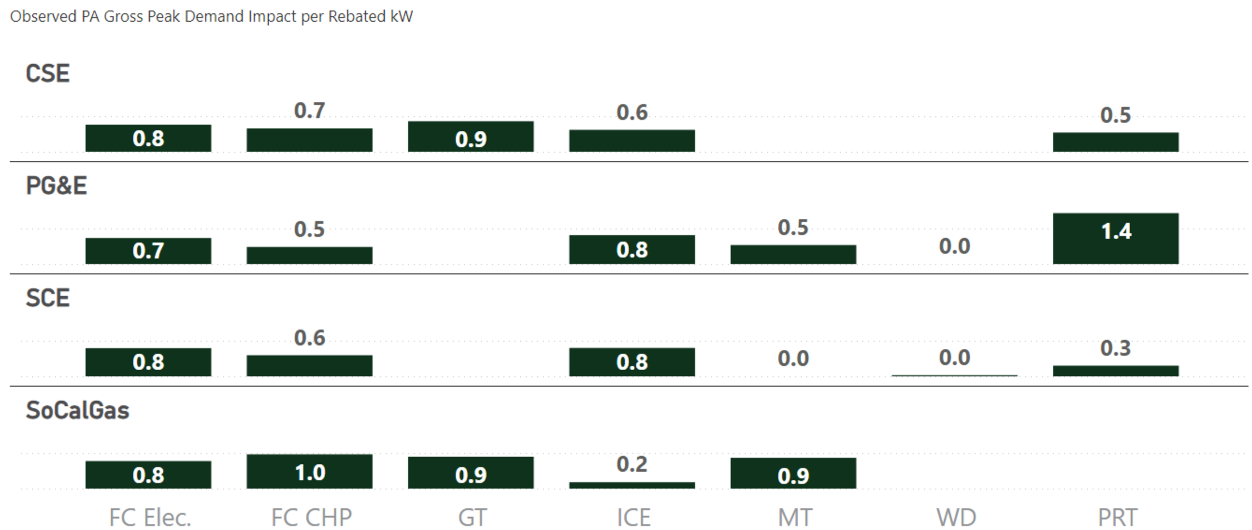


FIGURE C-66: 2021 OBSERVED IOU GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE AND ELECTRIC UTILITY

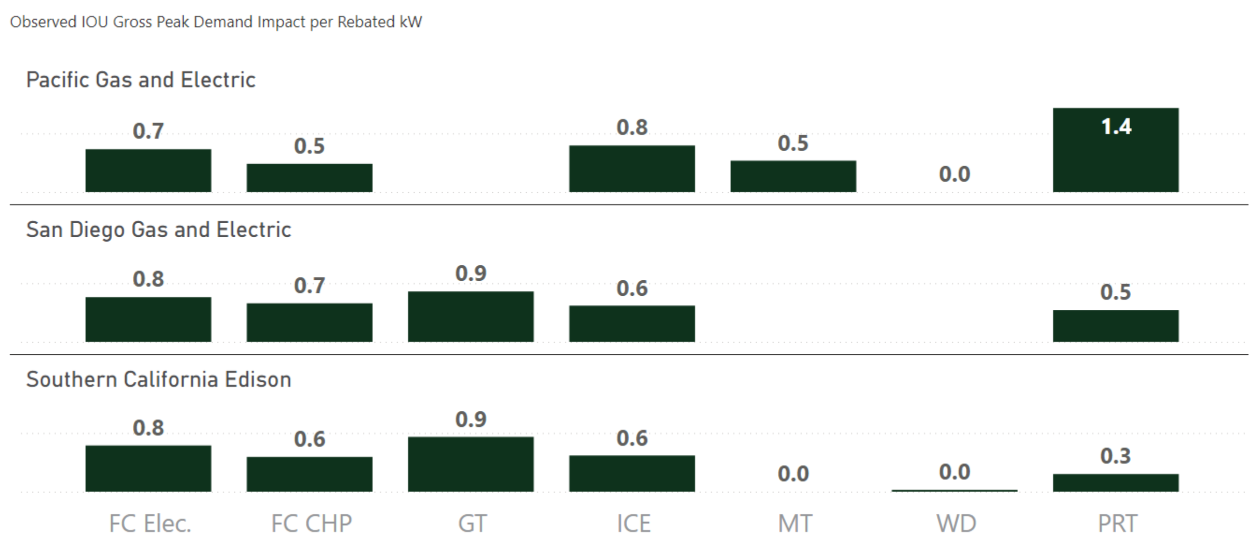


FIGURE C-67: 2021 OBSERVED PEAK HOUR GENERATION COMPARED TO AVERAGE TOP 100 HOUR GENERATION [PER KW]

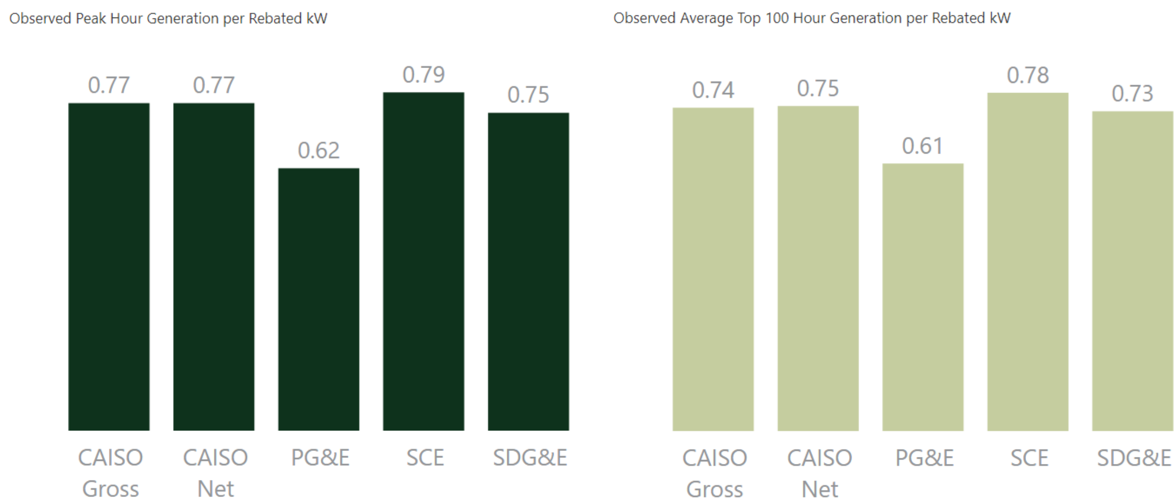
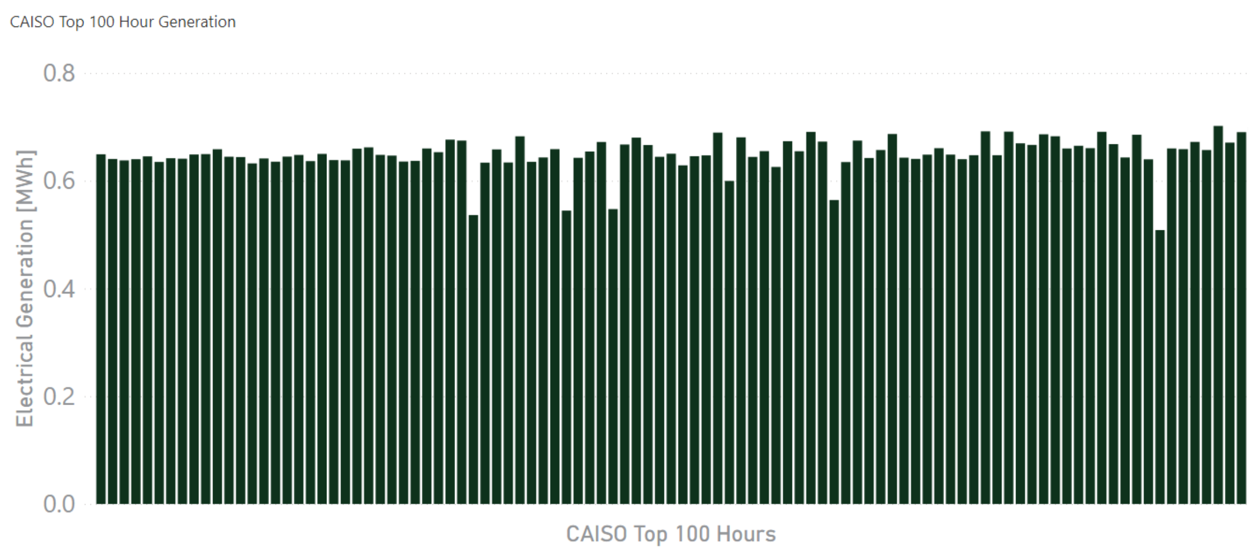


FIGURE C-68: OBSERVED CAISO TOP 100 HOUR GENERATION PER REBATED KW



C.4 ENVIRONMENTAL IMPACTS

C.4.1 Energy Storage

Nonresidential Storage

FIGURE C-69: GHG EMISSIONS (KG/KWH) FOR NONRESIDENTIAL SYSTEMS BY PAYMENT YEAR AND PV PAIRING (2021)

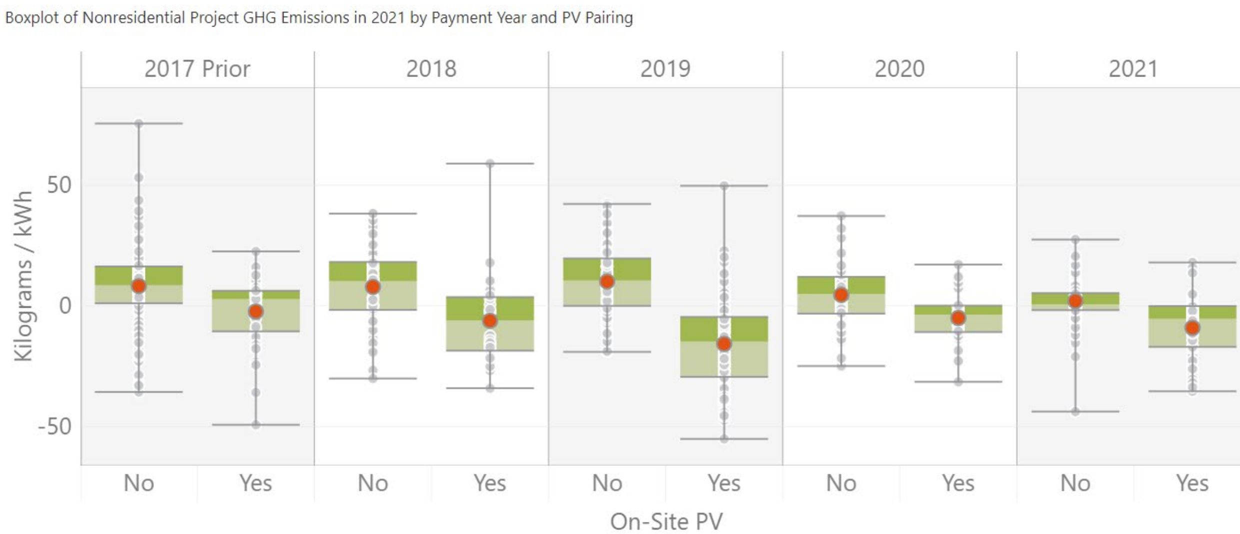


FIGURE C-70: NONRESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY SEASON AND PV PAIRING (2021)

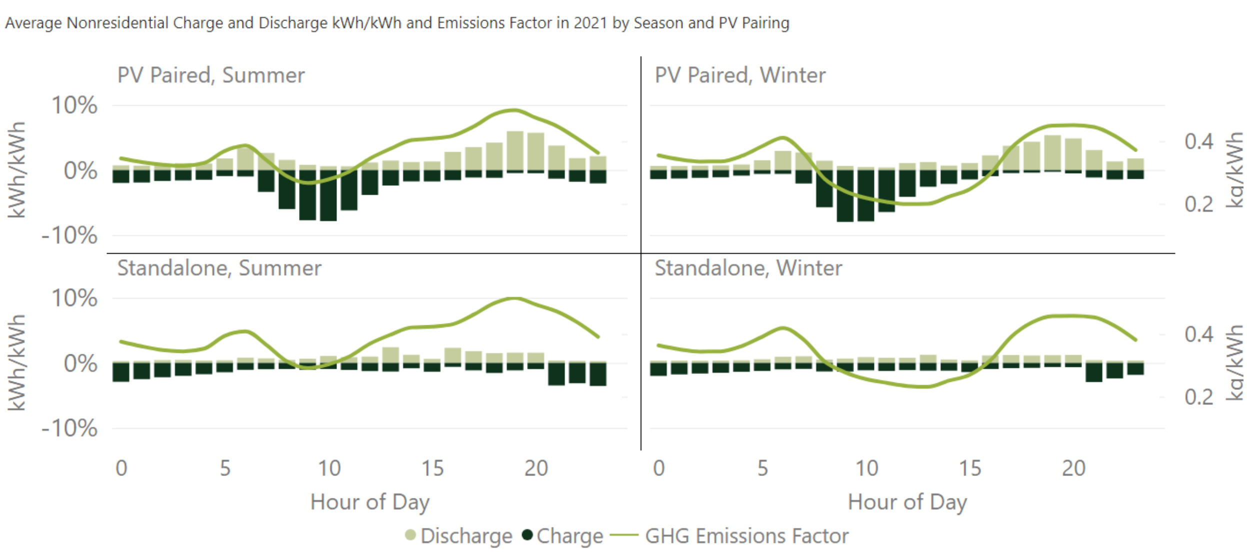


FIGURE C-71: NONRESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY SEASON AND PV PAIRING (2021)

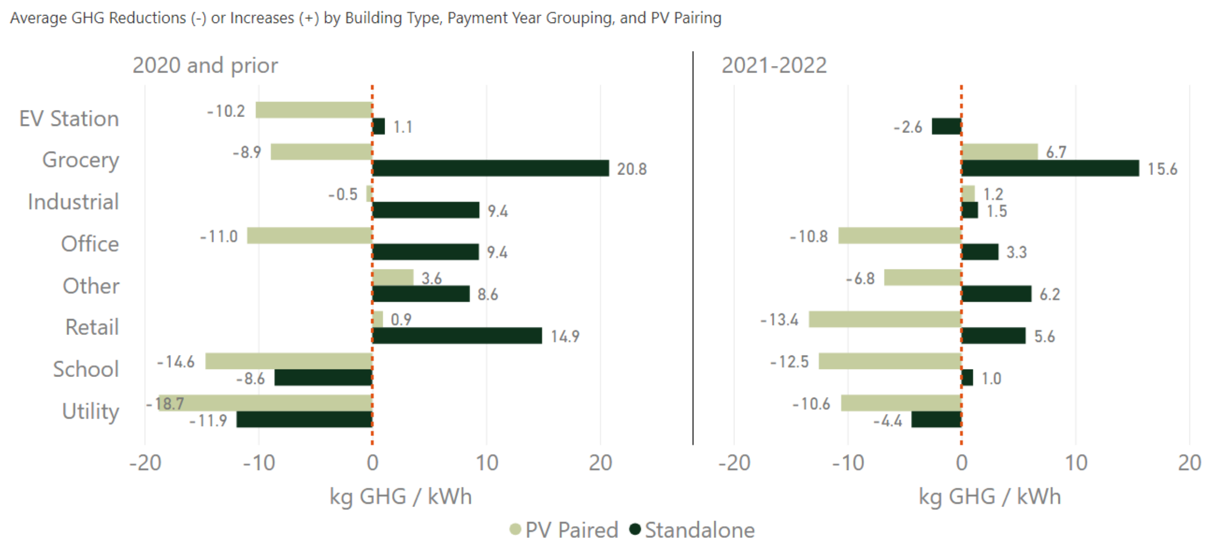
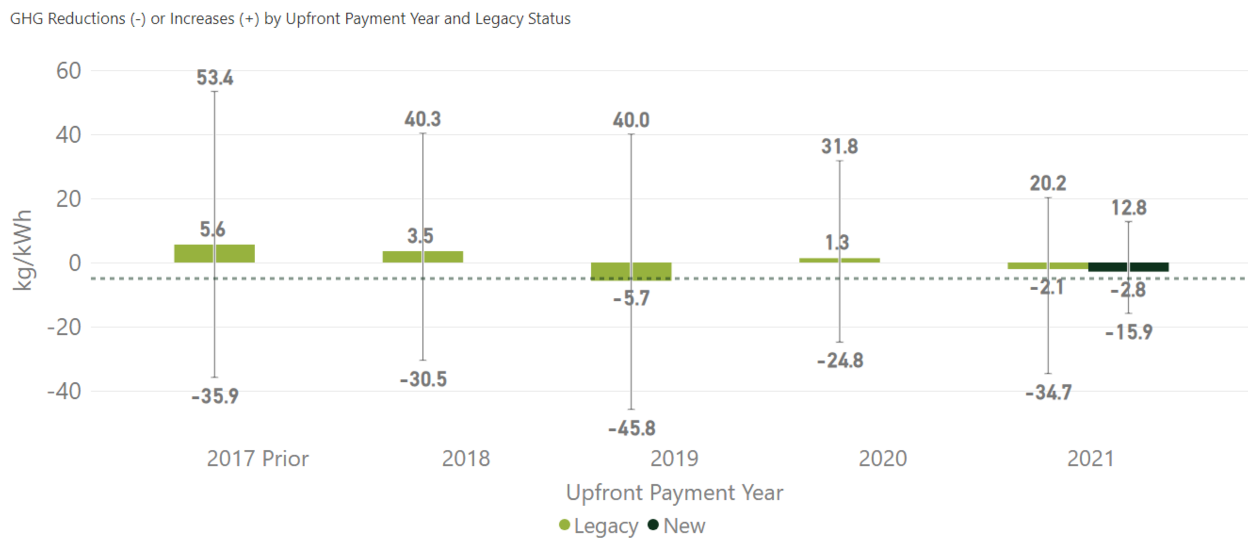


FIGURE C-72: NONRESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY LEGACY STATUS (2021)

FIGURE C-73: NONRESIDENTIAL GHG EMISSIONS BY PAYMENT YEAR AND LEGACY STATUS (2021)



Residential

FIGURE C-74: EMISSIONS (KG GHG/KWH) FOR RESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR (2021)

FIGURE C-75: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY SEASON AND PV PAIRING (2021)

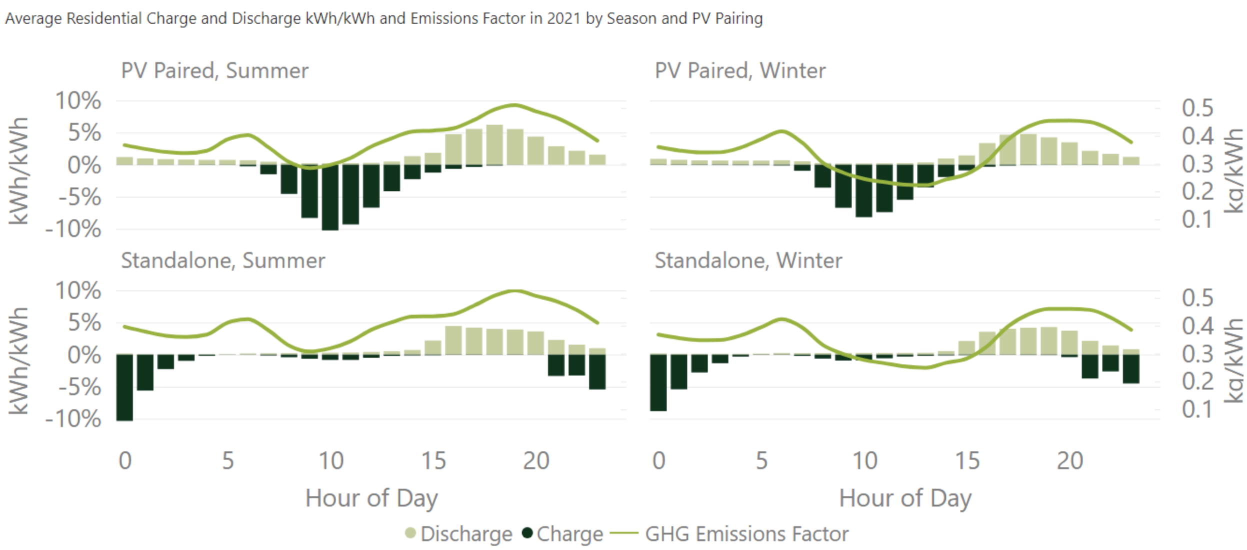


FIGURE C-76: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY SEASON AND EQUIPMENT (2021)

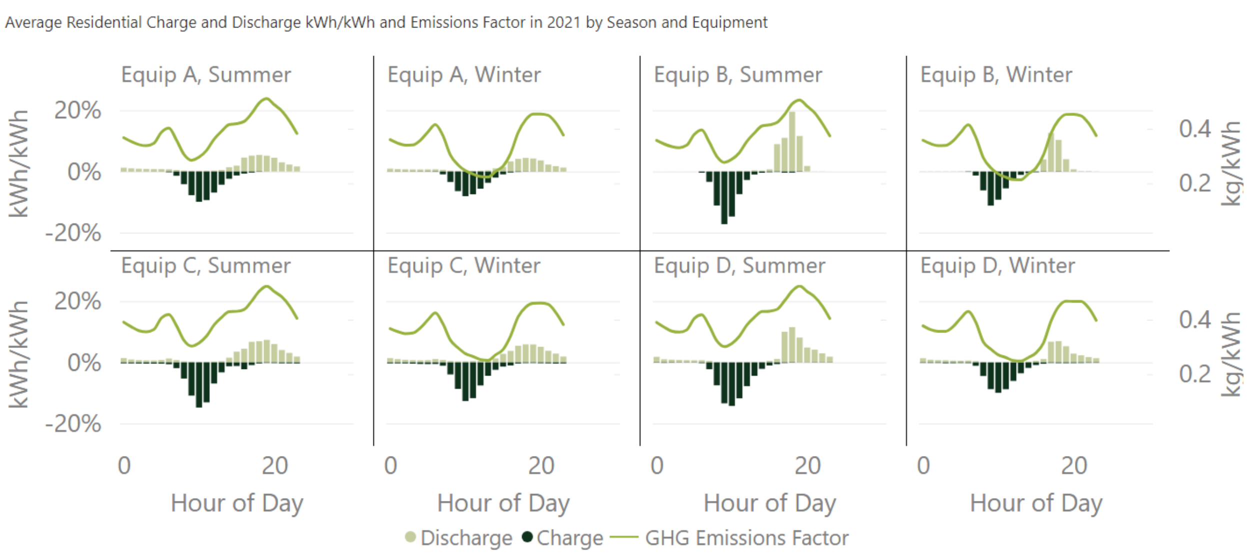


FIGURE C-77: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY OPERATING MODE (2021)

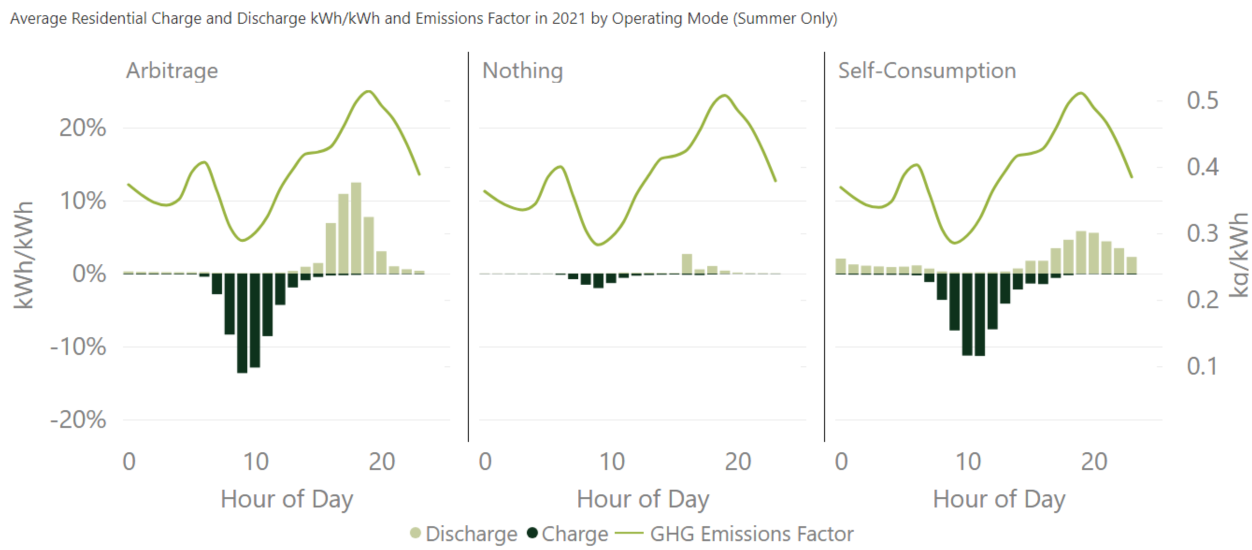


FIGURE C-78: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY PV PAIRING (2021)

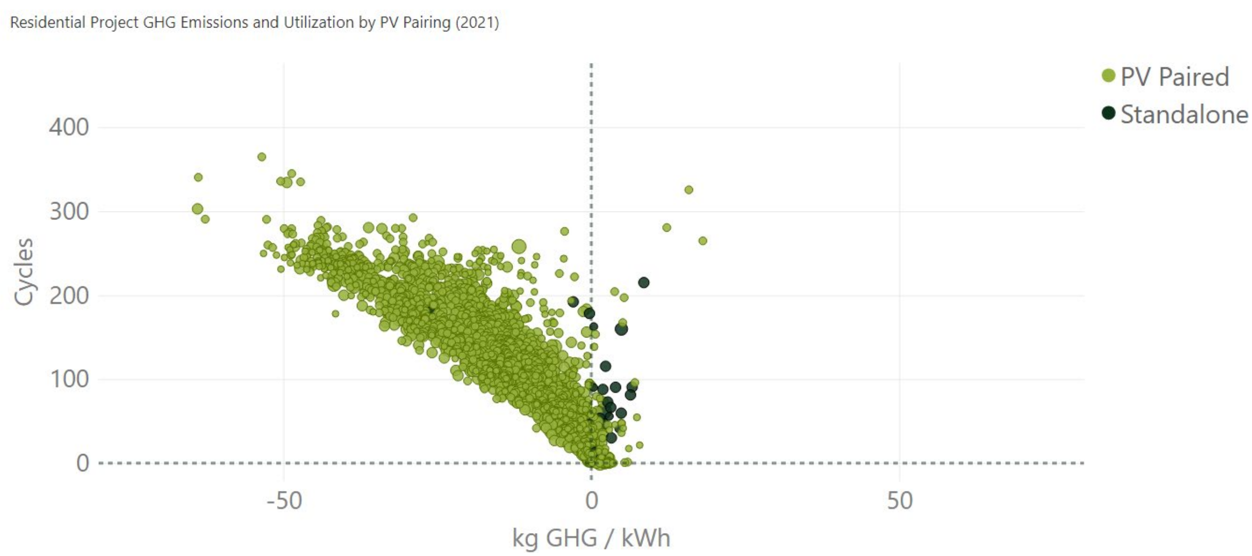


FIGURE C-79: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY OPERATING MODE (2021)

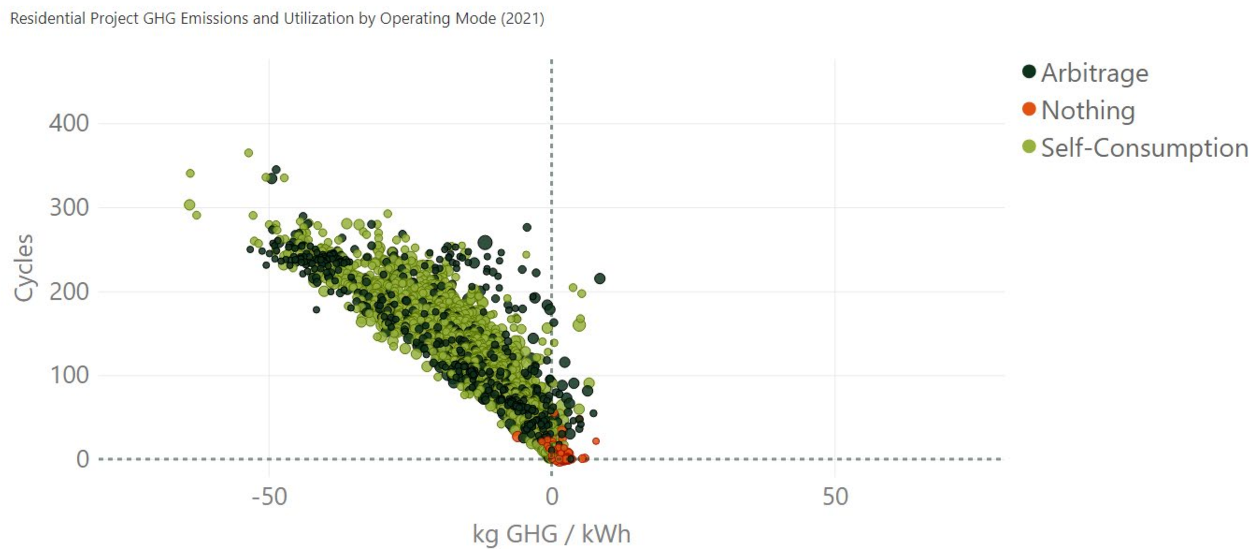
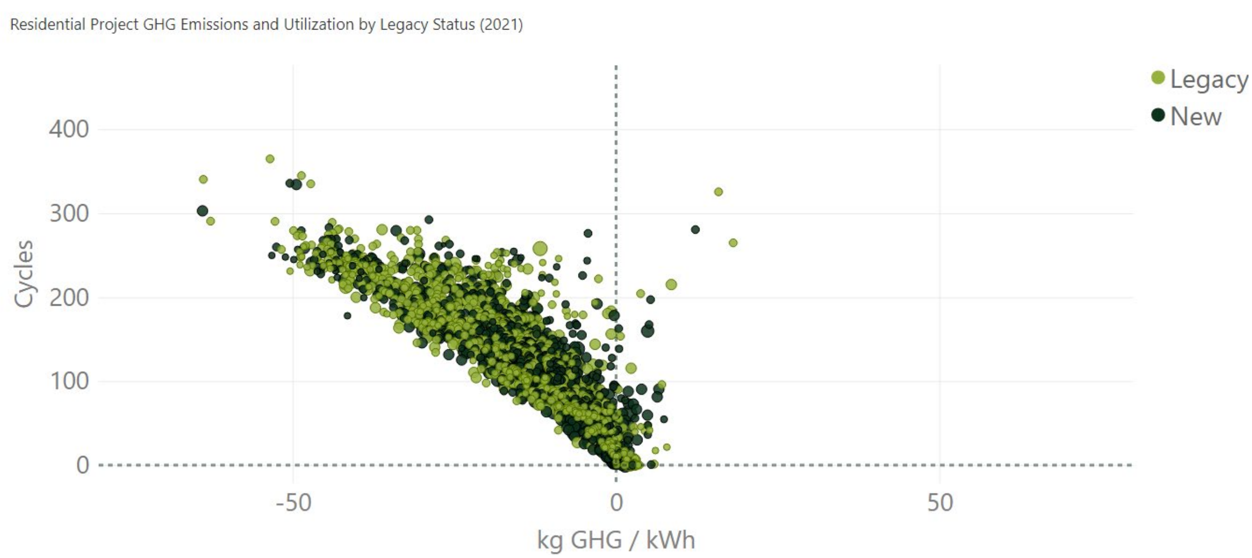


FIGURE C-80: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY LEGACY STATUS (2021)



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GHG Impact Summaries

FIGURE C-81: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY PA (2021)

PA	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
CSE	142	201	457	-2.9
PG&E	171	289	578	2.1
SCE	379	297	609	-2.3
SCG	38	406	863	-8.0
Overall	**730**	**282**	**586**	**-1.8**

FIGURE C-82: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA (2021)

PA	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
CSE	367	8	21	-18.0
PG&E	1195	8	22	-9.5
SCE	675	8	19	-20.8
SCG	28	8	20	-23.1
Overall	**2265**	**8**	**21**	**-14.2**

FIGURE C-83: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY PV PAIRING (2021)

On-site Generation	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
PV Paired	300	230	487	-8.7
Standalone	430	319	654	1.7
Overall	**730**	**282**	**586**	**-1.8**

FIGURE C-84: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA AND BY PV PAIRING (2021)

On-site Generation	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
PV Paired	2232	8	21	-14.5
Standalone	33	10	26	1.4
Overall	**2265**	**8**	**21**	**-14.2**

FIGURE C-85: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY LEGACY STATUS (2021)

Legacy Status	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
Legacy Projects	720	282	577	-1.8
New Projects	10	319	1177	-3.3
Overall	**730**	**282**	**586**	**-1.8**

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FIGURE C-86: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY LEGACY STATUS (2021)

Legacy Status	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
Legacy Projects	1067	7	18	-16.9
New Projects	1198	9	23	-12.2
Overall	**2265**	**8**	**21**	**-14.2**

FIGURE C-87: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY UPFRONT PAYMENT YEAR (2021)

Upfront Payment Year	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
2017 Prior	139	325	651	3.4
2018	91	271	540	-1.0
2019	238	184	378	-9.5
2020	107	367	793	1.3
2021	155	344	729	-2.6
Overall	**730**	**282**	**586**	**-1.8**

FIGURE C-88: SUMMARY OF RESIDENTIAL GHG IMPACTS BY UPFRONT PAYMENT YEAR (2021)

Upfront Payment Year	n Prj	Avg kW	Avg kWh	GHG (kg/kWh)
2018	154	6	16	-15.9
2019	278	7	16	-16.6
2020	489	7	18	-17.6
2021	1083	9	23	-13.6
2022	261	9	24	-8.8
Overall	**2265**	**8**	**21**	**-14.2**

C.4.2 Generation

Non-Renewable Generation Project Greenhouse Gas Impacts

FIGURE C-89: 2021 OBSERVED NON-RENEWABLE PROJECT GREENHOUSE GAS IMPACTS RATES BY TECHNOLOGY TYPE

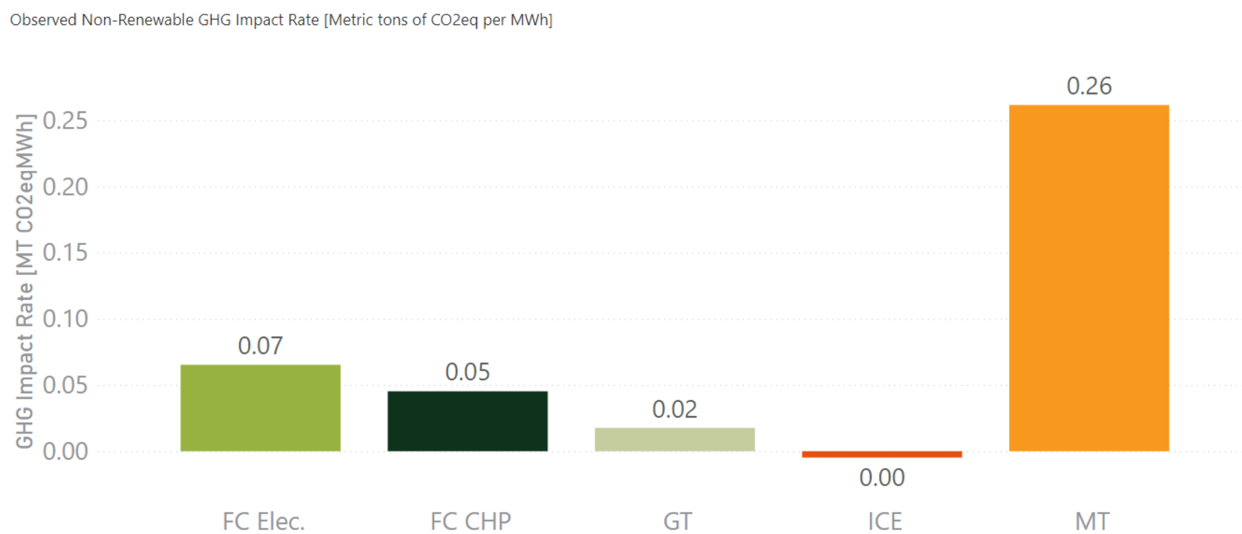
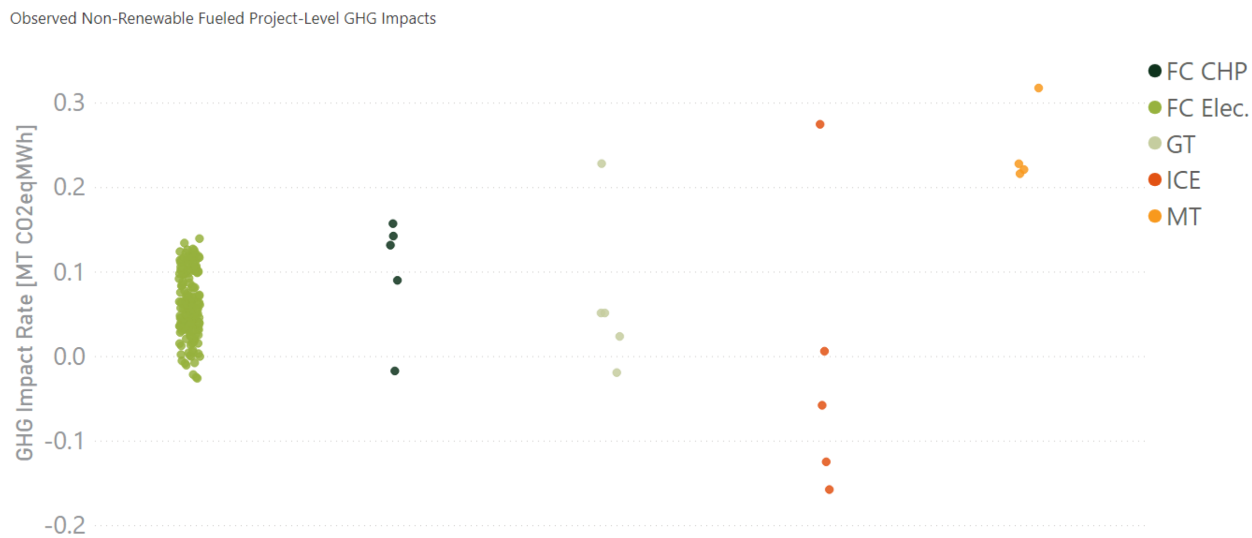


TABLE C-3: 2021 OBSERVED NON-RENEWABLE PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE

Equipment Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Cooling Services [D]	Total Avoided Emissions [E = B+C+D]	Emissions Impact [F=A-E]
Fuel Cell Electric	0.40	0.33	0	0	0.33	0.07
Fuel Cell CHP	0.48	0.35	0.08	0	0.43	0.05
Gas Turbine	0.71	0.32	0.38	0	0.69	0.02
Internal Combustion Engine	0.58	0.37	0.21	0	0.58	0
Microturbine	0.65	0.32	0.02	0.05	0.38	0.26
Total	**0.57**	**0.33**	**0.20**	**0**	**0.53**	**0.04**

FIGURE C-90: 2021 OBSERVED NON-RENEWABLE PROJECT-LEVEL GREENHOUSE GAS IMPACTS TECHNOLOGY TYPE



Renewable Biogas Project Impacts

FIGURE C-91: 2021 OBSERVED RENEWABLE PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE

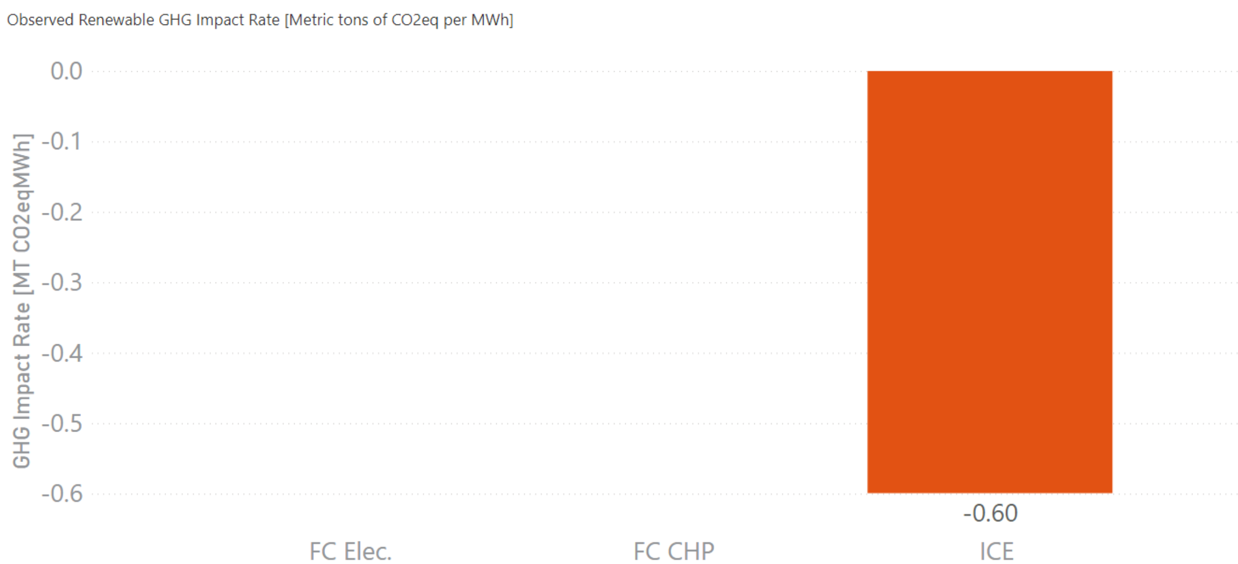


TABLE C-4: 2021 OBSERVED RENEWABLE PROJECT GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE

Equipment Type & Baseline Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Biogas Treatment [D]	Total Avoided Emissions [E = B+C+D]	Emissions Impact [F=A-E]
Internal Combustion Engine *(Flare)*	0.58	0.37	0.31	0.50	1.18	-0.60
Total	**0.58**	**0.37**	**0.31**	**0.50**	**1.18**	**-0.60**

Non-Fueled Projects Impacts

FIGURE C-92: 2021 OBSERVED NON-FUELED GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE

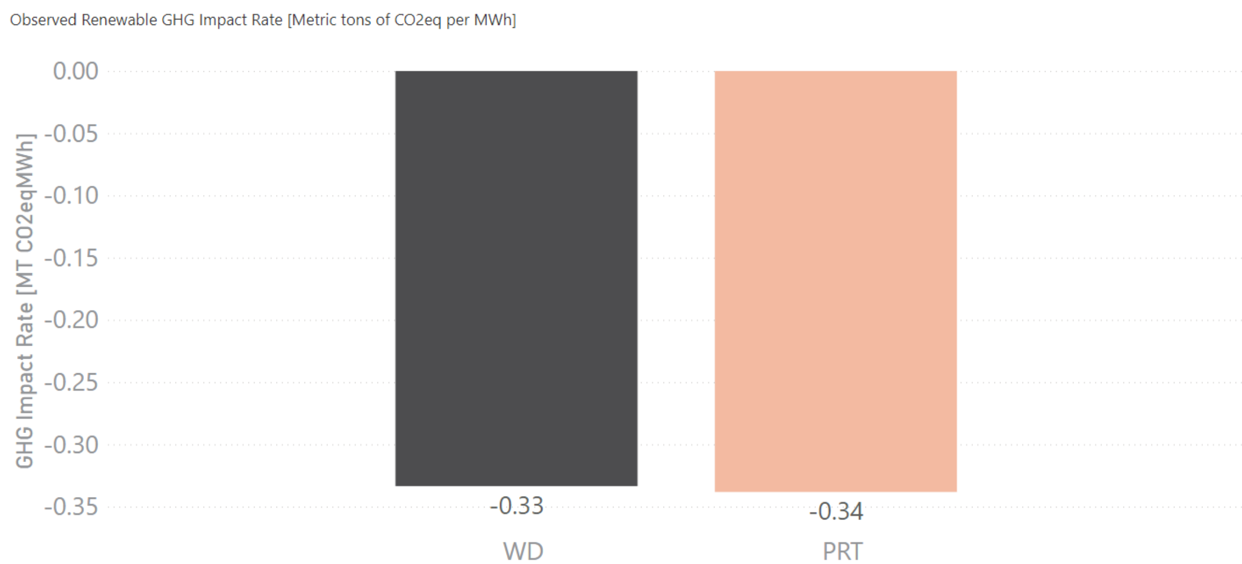


TABLE C-5: 2021 OBSERVED NON-FUELED PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE

Equipment Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Total Avoided Emissions [E = B]	Emissions Impact [F=A-E]
Wind	0	0.33	0.33	-0.33
Pressure Reduction Turbine	0	0.36	0.36	-0.36
Total	**0**	**0.34**	**0.34**	**-0.34**

C.5 UTILITY MARGINAL COST IMPACTS

C.5.1 Energy Storage

Nonresidential Utility Avoided Costs

FIGURE C-93: NONRESIDENTIAL AVOIDED COST $ PER CAPACITY KWH BY IOU (2021)

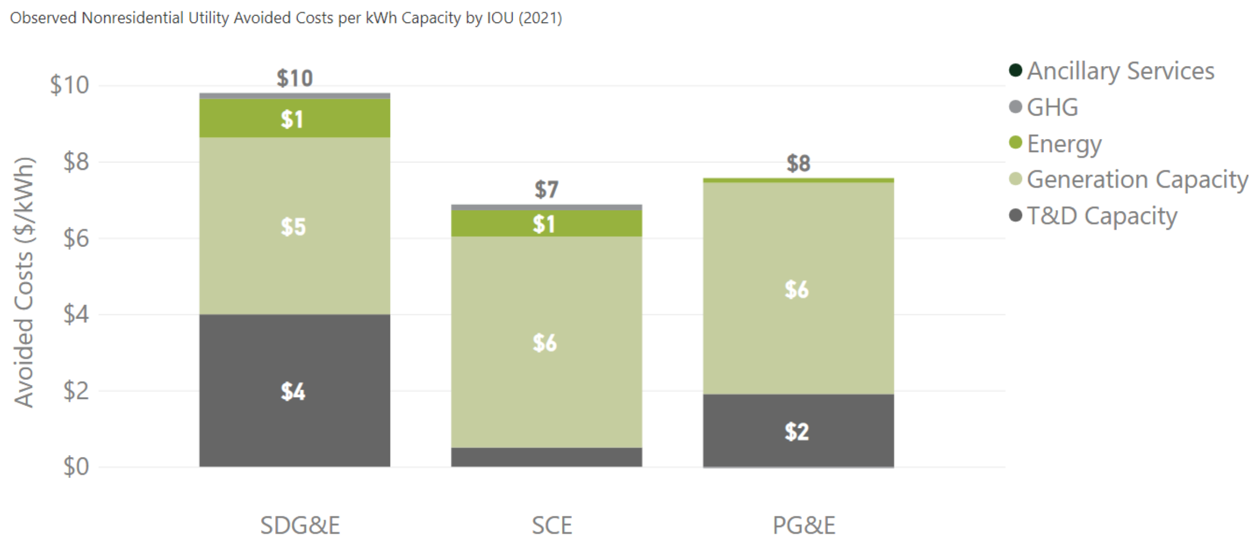


FIGURE C-94: NONRESIDENTIAL PROJECT AVOIDED COST $ PER CAPACITY KWH BY IOU (2021)

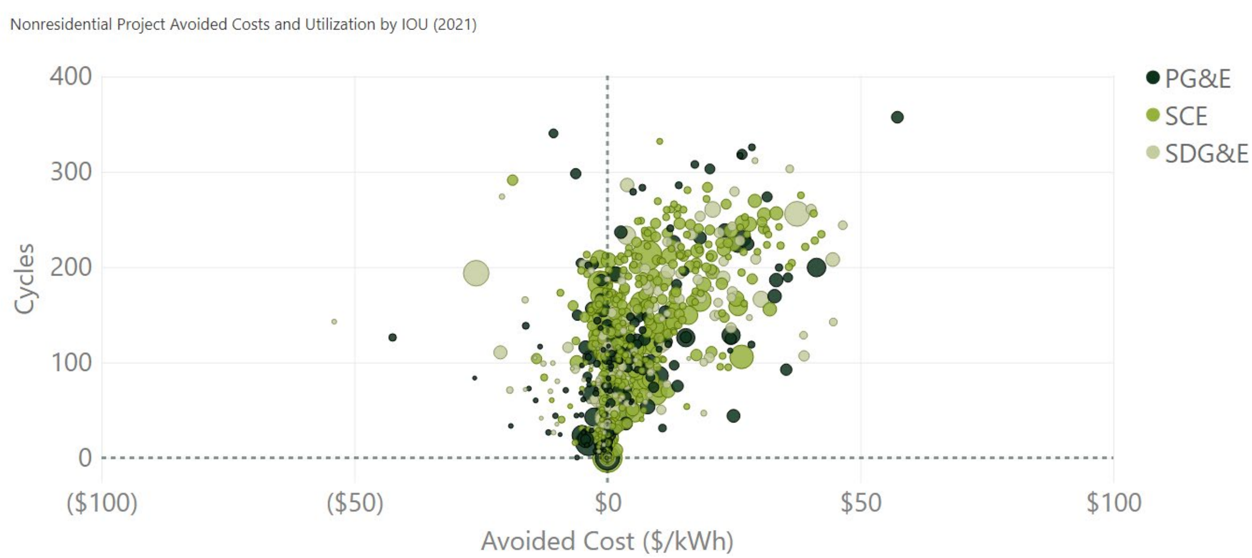


FIGURE C-95: BOX PLOT OF NONRESIDENTIAL AVOIDED COST $ PER CAPACITY KWH BY IOU AND PAYMENT YEAR (2021)

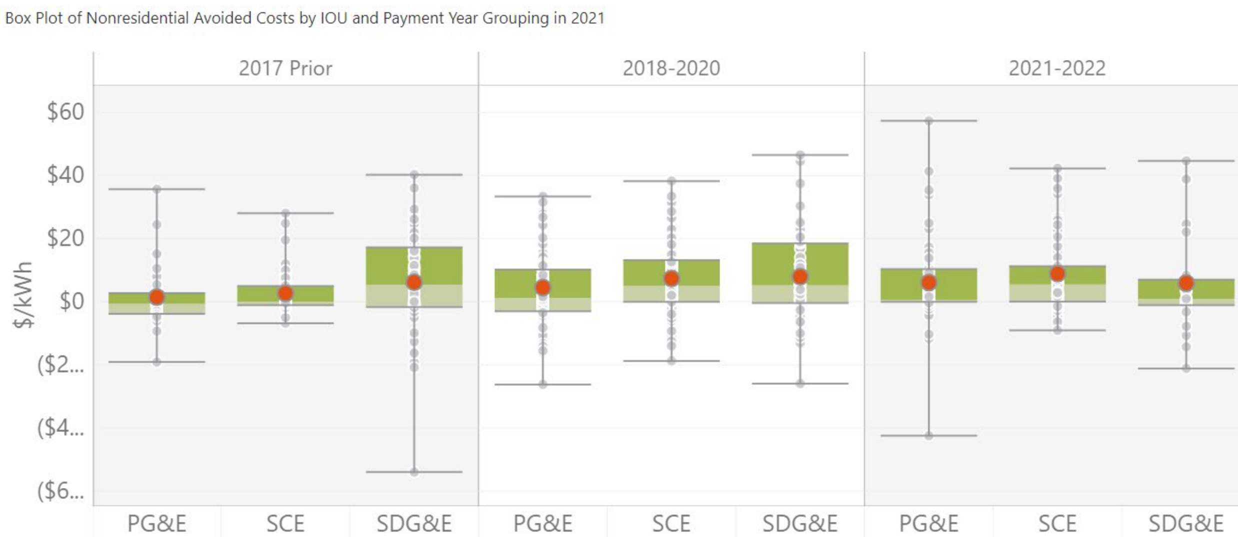
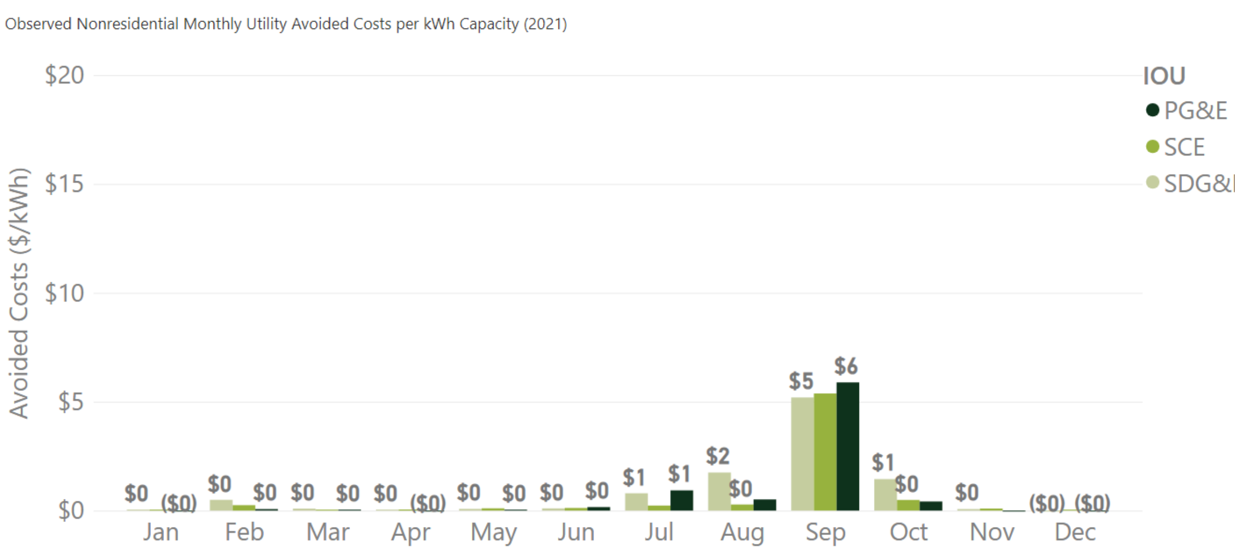


FIGURE C-96: NONRESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KW BY MONTH AND IOU (2021)



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Residential Utility Avoided Costs

FIGURE C-97: RESIDENTIAL MARGINAL AVOIDED COST $ PER KWH CAPACITY BY IOU (2021)

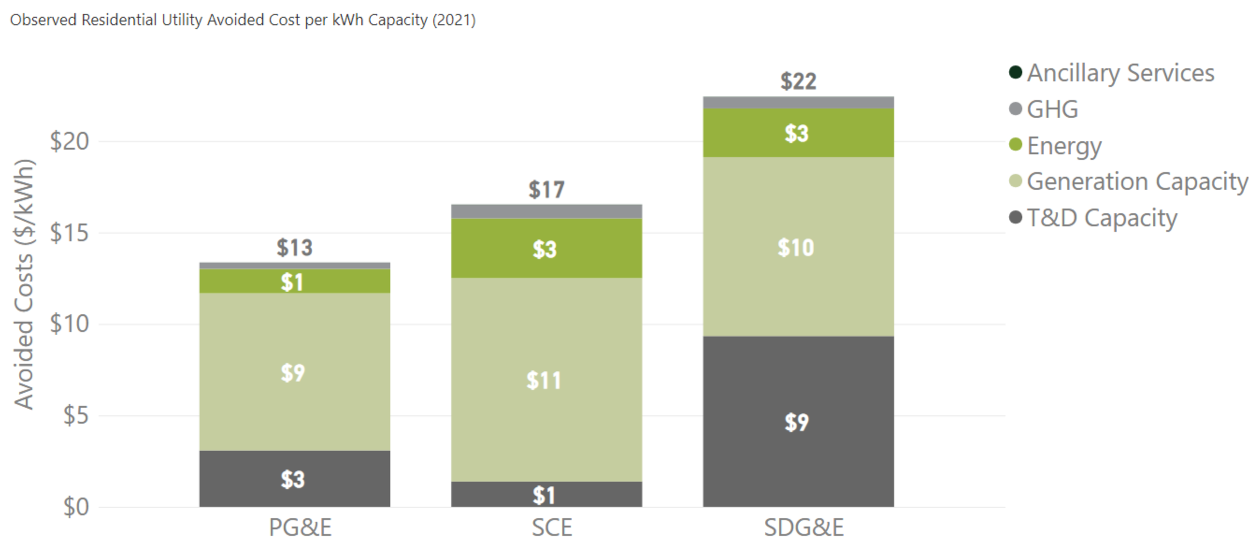


FIGURE C-98: RESIDENTIAL MARGINAL AVOIDED COST $ PER KWH CAPACITY BY PV PAIRING (2021)

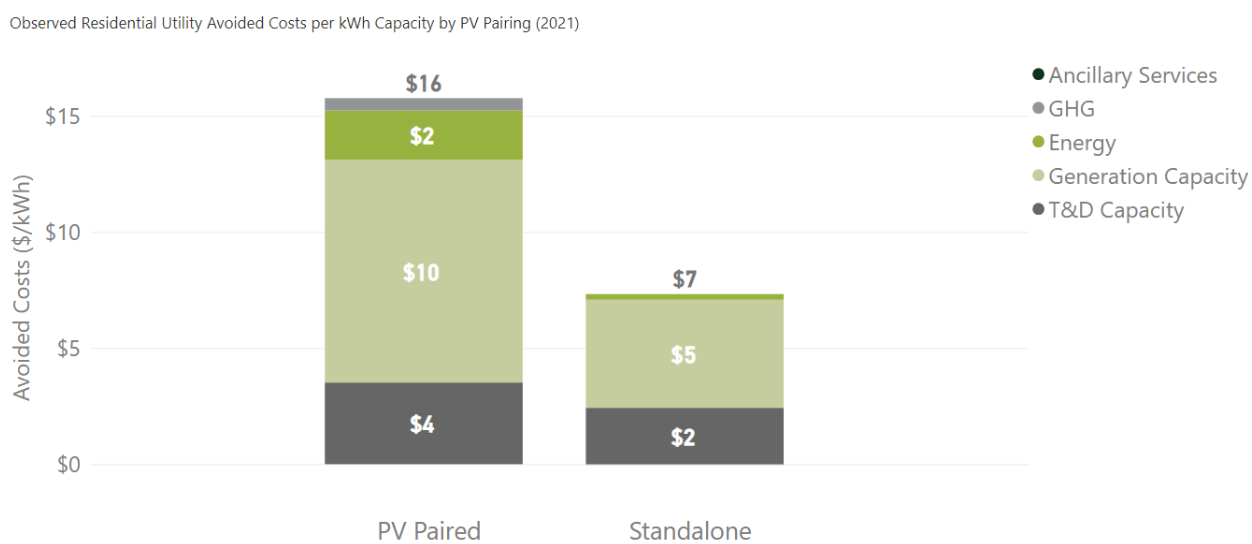


FIGURE C-99: RESIDENTIAL PROJECT AVOIDED COST $ PER CAPACITY KWH BY IOU (2021)

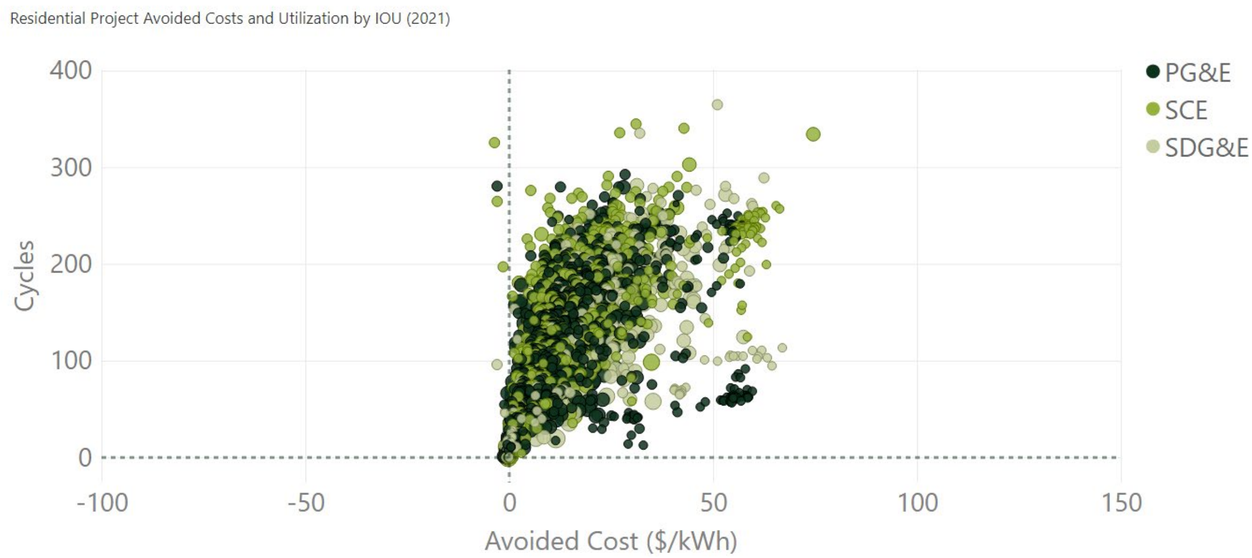


FIGURE C-100: BOX PLOT OF RESIDENTIAL AVOIDED COST $ PER CAPACITY KWH BY IOU AND PAYMENT YEAR (2021)

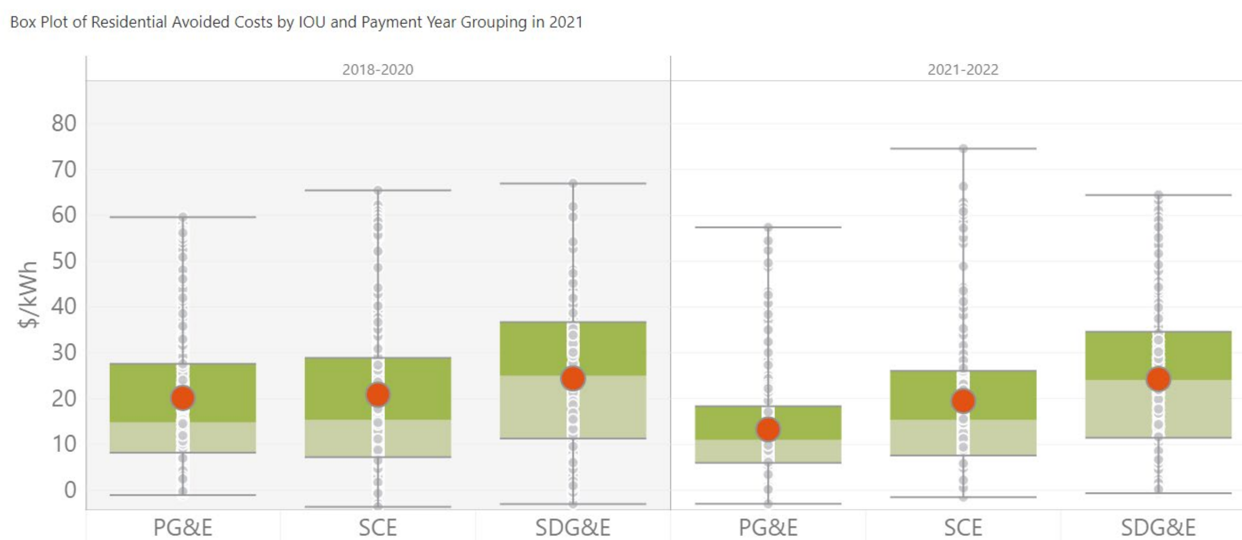
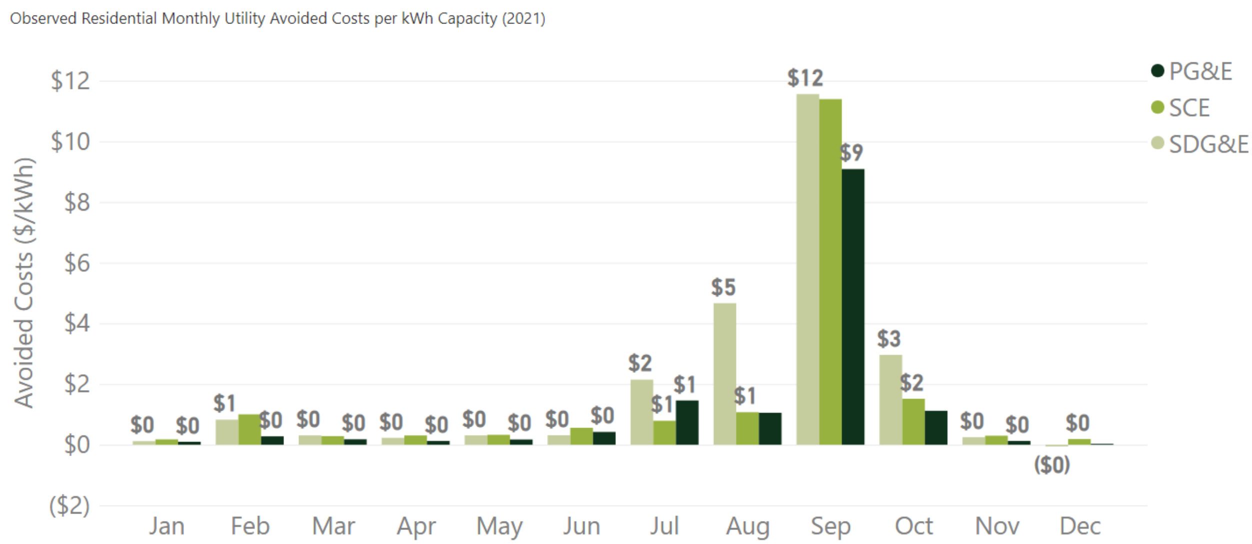


FIGURE C-101: RESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY MONTH AND IOU (2021)



Utility Avoided Cost Summaries

FIGURE C-102: SUMMARY OF 2021 NONRESIDENTIAL UTILITY AVOIDED COSTS ($/KWH)

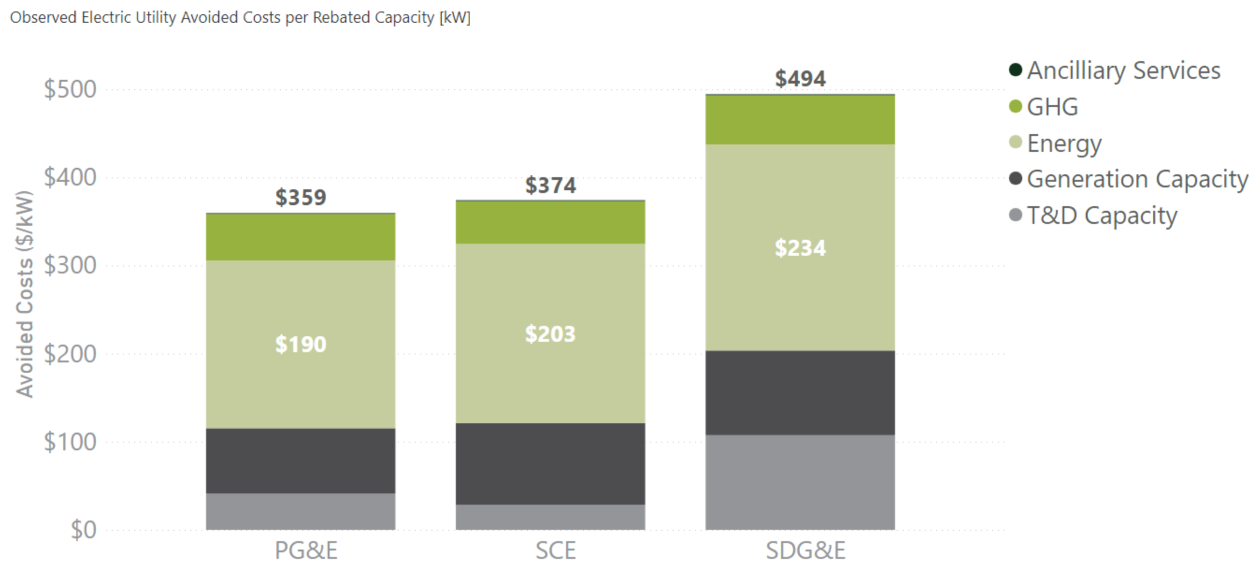
IOU	n Prj	Avg kW	Avg kWh	Anc Srvcs	Energy	GHG	Generation	T&D	Total
PG&E	171	289	578	$0	$0	($0)	$6	$2	$8
SCE	417	307	632	$0	$1	$0	$6	$1	$7
SDG&E	142	201	457	$0	$1	$0	$5	$4	$10
Overall	**730**	**282**	**586**	**$0**	**$1**	**$0**	**$5**	**$1**	**$7**

FIGURE C-103: SUMMARY OF 2021 RESIDENTIAL UTILITY AVOIDED COSTS ($/KWH)

IOU	n Prj	Avg kW	Avg kWh	Anc Srvcs	Energy	GHG	Generation	T&D	Total
PG&E	1195	8	22	$0	$1	$0	$9	$3	$13
SCE	701	8	19	$0	$3	$1	$11	$1	$17
SDG&E	369	8	21	$0	$3	$1	$10	$9	$22
Overall	**2265**	**8**	**21**	**$0**	**$2**	**$0**	**$9**	**$3**	**$16**

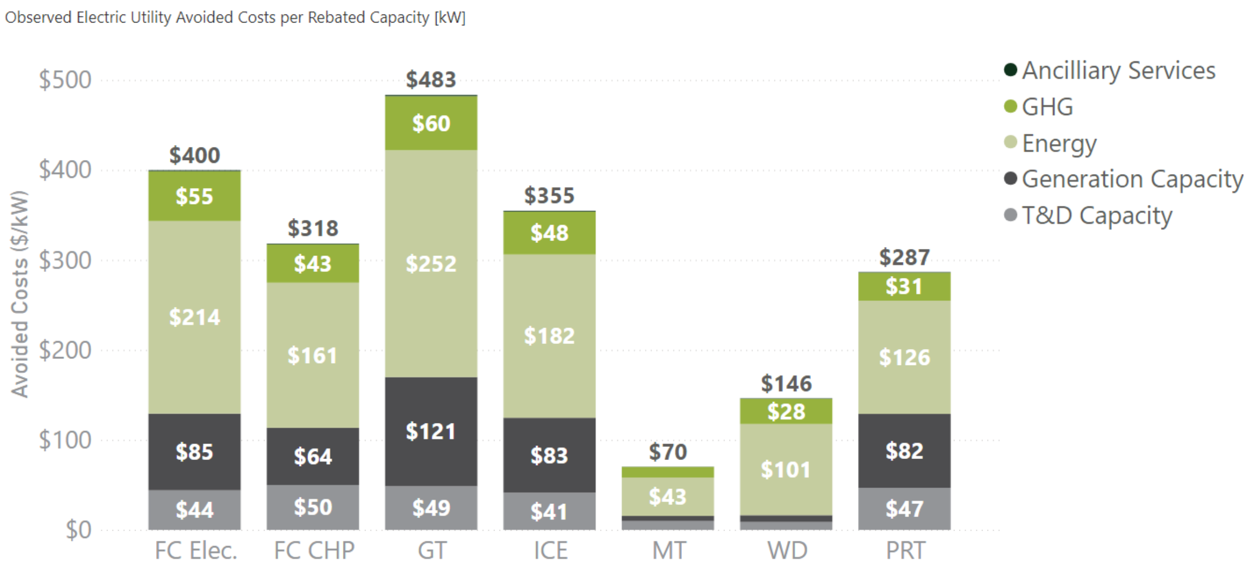
C.5.2 Generation

FIGURE C-104: 2021 OBSERVED GENERATION SYSTEM UTILITY AVOIDED COSTS BY IOU ($ PER REBATED KW)



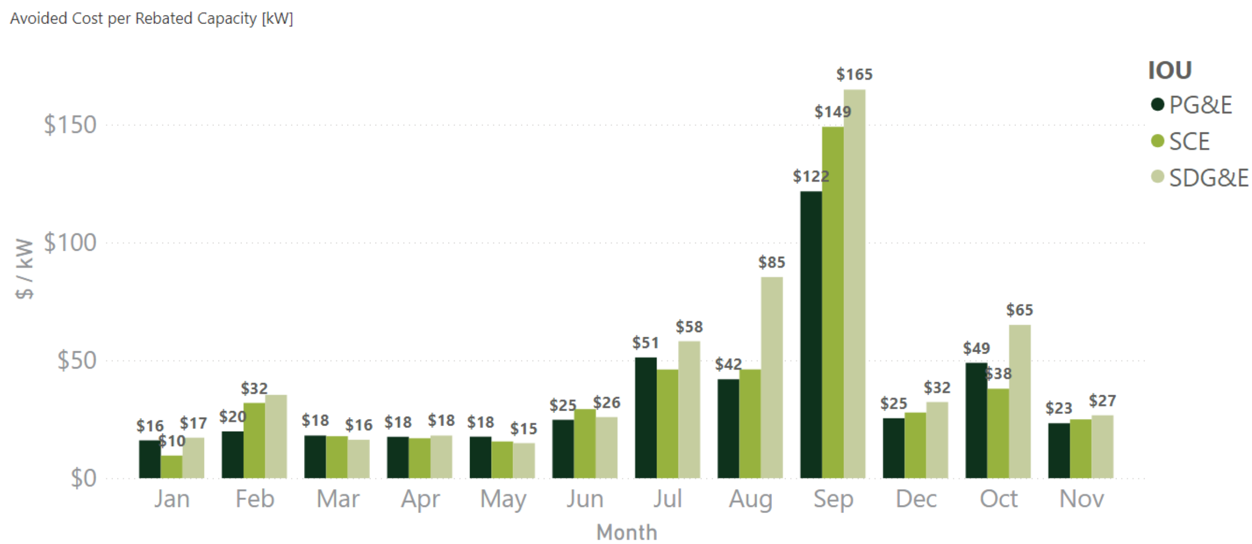
Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

FIGURE C-105: 2021 OBSERVED GENERATION SYSTEM UTILITY AVOIDED COSTS BY TECHNOLOGY TYPE ($ PER REBATED KW)



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

FIGURE C-106: 2021 OBSERVED GENERATION SYSTEM UTILITY AVOIDED BY IOU AND MONTH



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Utility Avoided Cost Generation Summaries

FIGURE C-107: 2021 GENERATION AVOIDED COST SUMMARY – BY UTILITY

Utility	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
PG&E	110	$1	$190	$53	$74	$41	$359
SCE	95	$1	$203	$49	$93	$28	$374
SDG&E	31	$1	$234	$56	$96	$107	$494
Overall	**236**	**$1**	**$202**	**$51**	**$86**	**$42**	**$382**

FIGURE C-108: 2021 GENERATION AVOIDED COST SUMMARY – BY EQUIPMENT TYPE

Equipment Type	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
FC CHP	7	$1	$161	$43	$64	$50	$318
FC Elec.	181	$1	$214	$55	$85	$44	$400
GT	3	$1	$252	$60	$121	$49	$483
ICE	24	$1	$182	$48	$83	$41	$355
MT	6	$0	$43	$12	$6	$10	$70
PRT	9	$1	$126	$31	$82	$47	$287
WD	6	$0	$101	$28	$8	$9	$146
Overall	**236**	**$1**	**$202**	**$51**	**$86**	**$42**	**$382**

FIGURE C-109: 2021 GENERATION AVOIDED COST SUMMARY – BY FUEL TYPE

Fuel Type	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
Non-Renewable	198	$1	$210	$53	$91	$44	$398
Other	16	$0	$95	$25	$23	$16	$161
Renewable	22	$1	$232	$61	$105	$50	$449
Overall	**236**	**$1**	**$202**	**$51**	**$86**	**$42**	**$382**

C.6 POPULATION IMPACTS

TABLE C-6: SAMPLE COMPOSITION OF 2021 SGIP STORAGE POPULATION BY CUSTOMER SECTOR

Customer Sector	Sample n	Population N	% of Projects Sampled	Sample Capacity (MWh)	Population Capacity (MWh)	% of Capacity Sampled
Nonresidential	923	1,145	81%	442	497	89%
Residential	2,266	24,728	9%	47	434	11%
Total	**3,189**	**25,873**	**12%**	**489**	**931**	**52%**

TABLE C-7: SAMPLE COMPOSITION OF 2021 SGIP GENERATION POPULATION BY TECHNOLOGY TYPE

Technology Type	Sample n	Population N	% of Projects Sampled	Sample Capacity [MW]	Population Capacity [MW]	% of Capacity Sampled
Fuel Cell Electric	209	316	66%	68	131	52%
Fuel Cell CHP	10	68	15%	9	25	37%
Gas Turbine	6	8	75%	85	99	86%
Internal Combustion Engine	25	48	52%	28	50	56%
Microturbine	9	18	50%	6	15	42%
Wind	6	26	23%	9	33	28%
Pressure Reduction Turbine	9	9	100%	3	3	100%
Waste Heat to Power	0	1	0%	0	0	0%
Total	**274**	**494**	**55%**	**208**	**354**	**59%**

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TABLE C-8: 2021 STORAGE POPULATION ELECTRIC ENERGY IMPACTS

Customer Sector	N	Population Discharge (MWh)	Population Charge (MWh)	Population Net Discharge (MWh)	Population RTE
Nonresidential	1,145	57,614	70,001	-12,387	82%
Residential	24,728	5,738	6,611	-872	87%
Total	**25,873**	**63,352**	**76,611**	**-13,259**	**83%**

TABLE C-9: 2021 GENERATION POPULATION ELECTRIC ENERGY IMPACTS

Technology Type	Population N	Population Generation [GWh]	Population CF	Population Electrical Efficiency	Population System Efficiency
Fuel Cell Electric	316	837	77.2%	48.4%	48.4%
Fuel Cell CHP	68	70	14.5%	38.4%	54.0%
Gas Turbine	8	657	72.6%	30.7%	78.1%
Internal Combustion Engine	48	272	55.6%	32.7%	71.1%
Microturbine	18	66	53.7%	26.0%	49.3%
Wind	26	79	23.8%	--	--
Pressure Reduction Turbine	9	10	26.6%	--	--
Waste Heat to Power	1	0	--	--	--
Total	**494**	**1990**	**--**	**--**	**--**

TABLE C-10: 2021 ENERGY STORAGE CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS AND NET PEAK HOUR)

Customer Sector	Population N	Population Gross Peak Hour Net Discharge [MW]	Population Net Peak Hour Net Discharge [MW]
Nonresidential	1,145	18.5	18.8
Residential	24,728	28.1	37.2
Total	**25,873**	**46.7**	**56.0**

TABLE C-11: 2021 GENERATION CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS AND NET PEAK HOUR)

Technology Type	Population N	Population Gross Peak Hour Generation [MW]	Population Net Peak Hour Generation [MW]
Fuel Cell Electric	294	91.35	60.90
Fuel Cell CHP	47	8.63	7.68
Gas Turbine	8	88.58	88.42
Internal Combustion Engine	48	36.26	15.18
Microturbine	18	7.30	5.24
Wind	24	0.17	3.21
Pressure Reduction Turbine	9	1.90	1.37
Waste Heat to Power	1	0	0
Total	**449**	**234.19**	**181.99**

TABLE C-12: 2021 ENERGY STORAGE CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 200 GROSS AND NET HOURS)

Customer Sector	Population N	Population Gross Top 100 Hour Net Discharge [MW]	Population Net Top 100 Hour Net Discharge [MW]
Nonresidential	1,145	12.2	15.6
Residential	24,728	20.5	21.0
Total	**25,873**	**32.6**	**36.6**

TABLE C-13: 2021 GENERATION CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 100 GROSS AND NET HOURS)

Technology Type	Population N	Population Average Gross Top 100 Hour Generation [MWh]	Population Average Net Top 100 Hour Generation [MWh]
Fuel Cell Electric	305	93.5	62.5
Fuel Cell CHP	56	7.9	7.1
Gas Turbine	8	82.0	88.0
Internal Combustion Engine	48	35.2	17.8
Microturbine	18	7.6	5.9
Wind	26	3.5	1.7
Pressure Reduction Turbine	9	1.4	1.5
Waste Heat to Power	1	0	0
Total	**471**	**231.1**	**184.5**

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TABLE C-14: 2021 ENERGY STORAGE POPULATION GREENHOUSE GAS IMPACTS

Customer Sector	N	Population Impact (MT CO_2)	Capacity MWh	MT / Capacity MWh
Nonresidential	1,145	-1,282	497	-2.6
Residential	24,728	-5,648	434	-13.0
Total	**25,873**	**-6,930**	**931**	**-7.4**

TABLE C-15: 2021 GENERATION POPULATION GREENHOUSE GAS IMPACTS

Technology Type	Fuel Type	Baseline Type	Population N	Population GHG Impact [MT CO_{2eq}]	GHG Impact Rate [MT CO_{2eq}/MWh]
Fuel Cell Electric	Non-Renewable Gas	N/A	316	47,298	0.12
Fuel Cell CHP	Renewable Gas	Flare	7	-3,825	-0.34
	Non-Renewable Gas	N/A	61	5,956	0.25
Gas Turbine	Renewable Gas	Flare	1	-39,274	-0.58
	Non-Renewable Gas	N/A	7	10,198	0.02
Internal Combustion Engine	Renewable Gas	Flare	25	-74,548	-0.53
		Vent	6	-104,076	-5.73
	Non-Renewable	N/A	17	2,174	0.02
Microturbine	Renewable Gas	Flare	7	-3,261	-0.47
	Non-Renewable Gas	N/A	9	11,769	0.25
	Other	Flare	2	-6,126	-0.54
Wind	Other	N/A	26	-24,932	-0.32
Pressure Reduction Turbine	Other	N/A	9	-3,386	-0.34
Waste Heat to Power	Other	N/A	1	0	0
Total	--	--	**493**	**-182,034**	**-0.09**

TABLE C-16: 2021 ENERGY STORAGE UTILITY MARGINAL COST IMPACTS

Customer Sector	Population N	Population Impact (Avoided Cost $)
Nonresidential	1,145	$3,522,656
Residential	24,728	$6,887,040
Total	**25,873**	**$10,409,696**

TABLE C-17: 2021 GENERATION UTILITY MARGINAL COST IMPACTS

Technology Type	Population N	Population Impact (Avoided Cost $)
Fuel Cell Electric	316	$50,780,911
Fuel Cell CHP	68	$3,731,499
Gas Turbine	8	$27,565,455
Internal Combustion Engine	48	$18,654,576
Microturbine	18	$3,784,300
Wind	26	$4,030,268
Pressure Reduction Turbine	9	$938,139
Waste Heat to Power	1	$0
Total	**494**	**$109,485,148**

APPENDIX D GREENHOUSE GAS IMPACTS ESTIMATION METHODOLOGY

This section describes the methodology used to estimate the impacts on greenhouse gas (GHG) emissions from the operation of Self-Generation Incentive Program (SGIP) projects. The GHGs considered in this analysis are limited to carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants that are potentially affected by the operation of SGIP projects.

Hourly GHG impacts are calculated for each SGIP project as the difference between the GHG emissions under observed conditions and assumed counterfactual baseline conditions. Baseline GHG emissions are those that would have occurred in the absence of the SGIP project. SGIP storage projects change the timing of demand for electricity from power plants. Because GHG emission rates from power plants vary, this shifting of electricity demand by storage projects changes the total quantity of emissions. SGIP generation projects displace baseline GHG emissions by satisfying site electric loads as well as heating/cooling loads, in some cases. SGIP generation projects fueled with biogas may reduce emissions of CH_4 in cases where venting of the biogas directly to the atmosphere would have occurred in the absence of the SGIP project.

The calculation of GHG impacts in terms of CO_2 equivalent (CO_2eq)[1] by date and time (hereafter referred to as "hour") is summarized by Equation D-1.

$$\Delta GHG_{i,h} = sgipGHG_{ih} - enoPP_{ih} - basePPchlr_{ih} - baseBlr_{ih} - baseBio_{ih}$$ **EQUATION D-1**

Negative GHG impacts (*ΔGHG*) indicate reduction in GHG emissions. Other terms in the equation represent SGIP system emissions (*sgipGHG*), power plant emissions (*enoPP*), baseline emissions associated with operations of heating and cooling equipment (*basePPchlr, baseBlr*), and baseline emissions associated with biogas (*baseBio*). Not all SGIP projects include all of the above variables. Inclusion is determined by the SGIP distributed generation technology and fuel type. For energy storage systems the equation simplifies to Equation D-2.

$$\Delta GHG_{i,h} = -enoPP_{ih}$$ **EQUATION D-2**

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1 Carbon dioxide equivalency describes, for a given mixture and amount of greenhouse gas, the amount of CO_2 that would have the same global warming potential (GWP), when measured over a specific time period (100 years). This approach must be used to accommodate cases where the assumed baseline is venting of CH_4 to the atmosphere directly.

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Detailed explanations of each of the equation terms are provided below.

SGIP Generation System GHG Emissions (*sgipGHG*)

For generation projects utilizing natural gas or renewable biogas fuel, GHGs are released by the SGIP system.

SGIP emission rates for SGIP projects that use natural gas fuel were calculated as:

$$sgipGHG_{ih} = Fuel_{ih} \times \frac{1ft^3CH_4}{935\ Btu} \times \frac{1lbmole\ CH_4}{379\ ft^3} \times \frac{1lbmole\ CO_2}{1lbmole\ CH_4} \times \frac{44lbs\ CO_2}{1lbmole\ CO_2} \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2} \qquad \textbf{EQUATION D-3}$$

SGIP emission rates for SGIP projects that use renewable biogas fuel were calculated as:

$$sgipGHG_{ih} = eno_{ih} \times \frac{3412\ Btu}{kWh} \times \left(\frac{1}{EFF_T}\right) \times \frac{1lbmole\ CH_4}{379\ ft^3} \times \frac{1lbmole\ CO_2}{1lbmole\ CH_4} \times \frac{44lbs\ CO_2}{1lbmole\ CO_2} \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2} \qquad \textbf{EQUATION D-4}$$

Where:

$sgipGHG_{ih}$	=	CO_2 emitted by SGIP project *i* during hour *h* [Metric ton/hr]
$Fuel_{ih}$	=	fuel consumption of SGIP project *i* during hour *h* [Btu]
eno_{ih}	=	electrical net output of SGIP project *i* during hour *h* [kWh]
EFF_T	=	measured electrical efficiency of technology T (see Table D-1). [Dimensionless fractional efficiency]

TABLE D-1: ELECTRICAL EFFICIENCY BY TECHNOLOGY TYPE USED FOR GHG EMISSIONS CALCULATION

	Electrical Efficiency [Eff_T]
Fuel Cell Electric	0.52
Fuel Cell CHP	0.29
Internal Combustion Engine	0.34
Microturbine	0.28
Gas Turbine	0.36

* Based on the lower heating value (LHV) metered data collected from SGIP projects

Central Station Electric Power Plant GHG Emissions (enoPP)

This section describes the methodology used to calculate impacts on CO_2 emissions from electric power plants. The methodology involves combining emission rates (in metric tons of CO_2 per kWh of electricity generated) that are service territory- and hour-specific with information about the magnitude and timing of SGIP system operation.

The service territory of the SGIP project is considered in the development of emission rates by accounting for whether the site is located in Pacific Gas and Electric's (PG&E's) territory (northern California) or in Southern California Edison's (SCE's) or Center for Sustainable Energy's (CSE's) territory (southern California). Variations in climate and electricity market conditions have an effect on the demand for electricity. This in turn affects the emission rates used to estimate the avoided CO_2 release by central station power plants. Lastly, timing of electricity generation affects the emission rates because the mix of high and low efficiency plants differs throughout the day. The larger the proportion of low efficiency plants used to generate electricity, the greater the avoided CO_2 emission rate.

The GHG Signal calculated by WattTime is used for estimating GHG impacts of SGIP systems. The CPUC-approved methodology that WattTime uses to calculate the GHG Signal assumes:

- The emissions of CO_2 from a conventional power plant depend upon its heat rate, which in turn is dictated by the plant's efficiency, and
- The mix of high and low efficiency plants in operation is reflected in the price and demand for electricity at that time.

The premise for hourly CO_2 emission rates calculated by WattTime is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of electricity reflect the market demand for electricity. As demand for electricity increases, all else being equal, the price of electricity will rise. To meet the higher demand for electricity, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission rate for CO_2. In other words, one can expect an emission rate representing the release of CO_2 associated with electricity purchased from the utility company to be higher during peak hours than during off-peak hours. Similarly, when prices are very low or negative, the CO_2 emission rate is assumed to be zero and implies renewable curtailment on the margin. Power plant emissions are calculated according to Equation D-5.

$$enoPP_{ih} = CO_2EF_{ih} \times eno_{ih} \times \frac{1\ MWh}{1000\ kWh}$$

EQUATION D-5

Where:

$enoPP_{ih}$	=	power plant GHG emissions impact for SGIP project *i* for hour *h* [Metric Ton CO_2/hr]

CO_2EF_{ih}	=	power plant GHG emissions per unit of electric energy for SGIP project *i* for hour *h* [Metric Ton CO_2/MWh]. Value from WattTime SGIP GHG Signal. https://sgipsignal.com/sgipmoer/ Version 2
eno_{ih}	=	electrical net output of SGIP project *i* during hour *h* [kWh/hr] For battery storage systems, negative while charging, positive while discharging. For generation systems, positive while generating electricity.

The equations used by WattTime to calculate values of CO_2EF are presented below for the sake of completeness and to provide context for the approaches used for some of the marginal costs (e.g., marginal wholesale electricity cost) discussed in Appendix E. For the impact evaluation, the CO_2EF values resulting from these equations were downloaded from an API maintained by WattTime.

First solve for Heat Rate *HR*:

$$HR\frac{\text{Btu}}{\text{kWh}} = \frac{\left(LMP\frac{\$}{\text{MWh}} - VOM\frac{\$}{\text{MWh}}\right)\frac{1\text{MWh}}{1000\text{kWh}}}{\left(GasP\frac{\$}{\text{MMBtu}} + GasTransP\frac{\$}{\text{MMBtu}} + EF\frac{\text{MT CO2}}{\text{MMBtu}}CapTradeP\frac{\$}{\text{MT CO2}}\right)\frac{1\text{MMBtu}}{1{,}000{,}000\text{Btu}}} \qquad \textbf{EQUATION D-6}$$

Where:

HR Implied heat rate of marginal generator (electrical conversion efficiency of a power plant consuming natural gas)

Units: Btu / kWh

LMP Price for electricity in the wholesale real-time market

Interval: 5 minutes

Units: $ / MWh

Source: CAISO OASIS real-time 5-minute locational marginal price for utility DLAPs. From menu at:

Prices—Energy Prices — Interval Locational Marginal Prices

DLAPs as ‘NODE_ID’ values:

- DLAP_PGAE-APND
- DLAP_SCE-APND
- DLAP_SDGE-APND

VOM Variable Operating and Maintenance Costs of a natural gas plant

Units: $ / MWh

Source: 2021 Avoided Cost Calculator

GasP Price for commodity gas
Interval: Daily
Units: $ / MMBtu HHV
Source: Natural Gas Intelligence (NGI)

GasTransP Price to transport natural gas
Units: $ / MMBtu HHV
Source: 2021 Avoided Cost Calculator

EF Emissions Factor for natural gas
Value: 0.0530703704
Units: MT CO_2 / MMBtu HHV
Source: 2021 Avoided Cost Calculator

CapTradeP Price associated with cap and trade compliance
Units: $ / MT CO_2
Source: CAISO OASIS Green House Gas Allowance Price (published daily).

Emissions are directly proportional to Heat Rate *HR* and calculated as:

$$CO_2EF\frac{\text{MT CO2}}{\text{MWh}} = HR\frac{\text{Btu}}{\text{kWh}}\frac{\text{1MMBtu}}{\text{1,000,000Btu}}\frac{\text{1000kWh}}{\text{1MWh}}EF\frac{\text{MT CO2}}{\text{MMBtu}}$$ **EQUATION D-7**

Electric Power Plant Operations Corresponding to Electric Chiller Operation (*basePPchlr*)

An absorption chiller may be used to convert heat recovered from SGIP CHP projects into chilled water to serve buildings or process cooling loads. As absorption chillers are assumed to replace the use of electric chillers that operate using electricity from a central power plant, there are avoided CO_2 emissions associated with these cogeneration facilities. The electricity that would have been serving an electric chiller in the absence of the cogeneration system was calculated as:

$$chlrElec_{ih} = Chilller_i \times heat_{ih} \times COP \ \times effElecChlr \times \left(\frac{1tonhrCooling}{12Mbtu}\right)$$ **EQUATION D-8**

Where:

$chlrElec_{ih}$	=	the electricity of a power plant that would be needed to provide baseline electric chiller for SGIP CHP project *i* for hour *h* [kWh]
$Chiller_i$	=	allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating and cooling, or cooling only), as determined from installation verification inspection reports (see Table D-2).

$heat_{ih}$	=	quantity of useful heat recovered for SGIP CHP project *i* for hour *h* from metering or ratio analysis [MBtu]
COP	=	0.6 – assumed efficiency of the absorption chiller using heat from SGIP CHP project [$Mbtu_{out}/Mbtu_{in}$]
effElecChlr	=	0.634 - assumed efficiency of the baseline new standard efficiency electric chiller [kWh/tonhr·Cooling]

TABLE D-2: ASSIGNMENT OF CHILLER ALLOCATION FACTOR

Project Design	$Chiller_i$
Heating and Cooling	0.5
Cooling Only	1
Heating Only	0

Baseline GHG Emissions from Power Plant Operations for chiller operations

The location- and hour-specific CO_2 emissions rate, when multiplied by the electricity requirements of a baseline chiller, estimates the hourly emissions avoided.

$$basePpChiller_{ih} = CO_2EF_{ih} \times chlrElec_{ih}$$

EQUATION D-9

Where:

$basePpChiller_{ih}$	=	the baseline power plant GHG emissions avoided due to SGIP CHP project *i* delivery of cooling services for hour *h* [Metric Ton CO_2/hr]

Boiler GHG Emissions (*baseBlr*)

A heat exchanger is typically used to transfer useful heat recovered from SGIP CHP projects to building or process heating loads. Using recovered heat in lieu of natural gas in this manner helps reduce CO_2 emissions. The equation below describes impacts of SGIP CHP projects providing heating services.

$$baseBlr_{ih} = Boiler_i \times heat_{ih} \times effHx \times \frac{1}{effBlr} \times \frac{1ft^3CH_4}{935\ Btu} \times \frac{1{,}000\ Btu}{1\ Mbtu} \times \frac{1\ lbmoleCO_2}{1lbmoleCH_4} \times \frac{44\ lbs\ CO_2}{1lbmole\ CO_2} \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2}$$

EQUATION D-10

Where:

$baseBlr_{ih}$	=	CO_2 emissions of the baseline natural gas boiler for SGIP CHP project *i* for hour *h* [Metric tons CO_2/hr]
effBlr	=	0.8 - assumed efficiency of the baseline natural boiler, based on previous cost effectiveness evaluations [$Mbtu_{out}/Mbtu_{in}$]
$Boiler_I$	=	allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating and cooling, or cooling only), as determined from installation verification inspections report (see Table D-3).

$heat_{ih}$	=	the quantity of useful heat recovered for SGIP CHP project *i* for hour *h* from metering or ratio analysis [MBtu]
effHX	=	0.9 – assumed efficiency of the SGIP CHP project's primary heat exchanger

TABLE D-3: ASSIGNMENT OF BOILER ALLOCATION FACTOR

Project Design	$Boiler_i$
Heating and Cooling	0.5
Cooling Only	0
Heating Only	1

Biogas GHG Emissions (*baseBio*)

Distributed generation projects powered by renewable biogas carry an additional GHG reduction benefit. The baseline treatment of biogas is an influential determinant of GHG impacts for renewable-fueled SGIP projects. Baseline treatment refers to the typical fate of the biogas in lieu of use for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared).

There are two common sources of biogas found within the SGIP: landfills and digesters. Digesters in the SGIP to date have been associated with water resource recovery facilities (WRRF), food processing facilities, and dairies. Because of the importance of the baseline treatment of biogas in the GHG analysis, these facilities were contacted in 2009 to more accurately estimate baseline treatment. This resulted in the determination that venting is the customary baseline treatment of biogas for dairy digesters, and flaring is the customary baseline for all other renewable fuel sites. Baseline treatments of biogas for different biogas sources and facility types are described below.

For dairy digesters the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2,000 dairies in California, conventional manure management practice for flush dairies[2] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into CO_2 and CH_4. These lagoons are typically uncovered, so all CH_4 generated in the lagoon escapes into the atmosphere. Currently, there are no statewide requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for

2 Most dairies manage their waste via flush, scrape, or some mixture of the two processes. While manure management practices for any of these processes will result in CH_4 being vented to the atmosphere, flush dairies are the most likely candidates for installing anaerobic digesters (i.e., dairy biogas projects).

volatile organic compounds. This information and the site contacts support a biogas venting baseline for dairies.

For other digesters, including WRRFs and food processing facilities, the baseline is not quite as straightforward. There are almost 250 WRRFs in California, and the larger facilities (i.e., those that could generate 1 MW or more of electricity) are typically required to capture and destroy methane; therefore, flaring is used as the biogas baseline.

Defining the biogas baseline for landfill gas recovery operations presented a challenge in past SGIP impact evaluations. California law requires most landfills with at least 450,000 tons of waste in place to collect and either flare or use their gas. Installation verification inspection reports and renewable-fueled distributed generation landfill site contacts verified that they would have flared their CH_4 in the absence of the SGIP. Therefore, the biogas baseline assumed for landfill facilities is flaring of the $CH_{4.}$

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for renewable fuel use incentives was expanded to include “directed biogas” projects. Deemed renewable fuel use projects, directed biogas projects were eligible for higher incentives under the SGIP. Directed biogas projects purchased biogas fuel that is produced at another location. The procured biogas was processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased gas was not likely to be delivered and used at the SGIP renewable fuel use project, directed biogas projects were treated as renewable fuel use projects for GHG impacts purposes.

All directed biogas projects included in the 2021-2022 impacts evaluation have met their contractual procurement requirements for biogas and are assumed to no longer procure renewable fuel. For GHG impacts purposes these projects were assumed to use natural gas during 2021-2022. The requirements lasted five years after the upfront payment date for PY10 and earlier projects, and 10 years after the upfront payment date for PY11 and later projects.

GHG Emissions of Flared Biogas

Methane is naturally created in landfills, wastewater treatment plants, and dairies. If not captured, the CH_4 escapes into the atmosphere contributing to GHG emissions. Capturing the CH_4 provides an opportunity to use it as a fuel. When captured CH_4 is not used to generate electricity or satisfy heating or cooling loads, it is burned in a flare.

In situations where flaring occurs, baseline GHG emissions comprise CO_2 only. The flaring baseline was assumed for the following types of biogas projects:

- Facilities using digester gas (with the exception of dairies),

- Landfill gas facilities, and

The assumption is that the flaring of CH_4 would have resulted in the same amount of CO_2 emissions as occurred when the CH_4 was captured and used in the SGIP project to produce electricity.

$$baseBio_{ih} = sgipGHG_{ih}$$

EQUATION D-11

GHG Emissions of Vented Biogas

Methane capture and use at renewable fuel use facilities where the biogas baseline is venting avoids release of CH_4 directly into the atmosphere. The venting baseline was assumed for all dairy digester SGIP projects. Biogas consumption is typically not metered at SGIP projects. Therefore, CO_2eq emission rates were calculated by assuming an electrical efficiency.

$$baseBio_{ih} = eno_{ih} \times \frac{3412\ Btu}{kWh} \times \frac{1}{EFF_T} \times \frac{1 ft^3 CH_4}{935\ Btu} \times \frac{1 lbmole CH_4}{379\ ft^3 CH_4} \times \frac{16 lbs CH_4}{lbmole CH_4} \times \frac{1\ metric\ ton}{2{,}205\ lbs} \times \frac{21\ metric\ tons\ CO_2}{1\ metric\ ton\ CH_4}$$

EQUATION D-12

Where:

$baseBio_{ih}$	=	CO_2eq emissions of the baseline methane emissions for SGIP CHP project *i* for hour *h* [Metric tons CO_2/hr]
EFF_T	=	electrical efficiency of technology T (see Table D-1).

APPENDIX E ELECTRIC UTILITY AVOIDED COSTS

Evaluation of SGIP impacts includes impacts on electric utility costs. These impacts are not measured directly. Information from secondary sources is incorporated to estimate these impacts. The approach used to estimate electric utility avoided costs is described in this appendix. Key data sources are summarized below.

E3 Avoided Cost Calculator (ACC). ACC forecasts of distribution capacity costs, transmission capacity costs, and generation capacity costs were included in the impacts evaluation. The ACC is primarily used as a planning tool rather than for impacts evaluation, as it contains 31-year forecasts (2022-2052) for costs and emissions. The forecasts are based on assumed, typical weather and market conditions. However, these forecasts are suitable for estimating marginal avoided costs of the three capacity costs due to the long-term nature of capacity expansion. Additionally, assumptions from the ACC are incorporated into calculation of the GHG Signal (see Appendix D), as well as into several cost components as described below.

CAISO Real-Time Locational Marginal Price Data (RT-LMP). Real-time LMPs serve as the measure of marginal electric energy prices in the impacts evaluation in order to maintain consistency with the GHG Signal and estimates of GHG impacts. In the RT-LMP data, Energy costs and GHG Cap & Trade costs are bundled together and reported as the 'Energy' price. To maintain consistency with ACC methods, the RT-LMP values are separated into Energy and GHG components.

WattTime SGIP GHG Signal. Values of the GHG Signal are used to estimate Cap & Trade costs. Data sources for the GHG signal include the ACC and CAISO data (see Appendix D for detailed description of GHG Signal).

Each of the components of electric utility marginal costs is described below.

E.1 ENERGY

$$Energy \frac{\$}{\text{MWh}} = LMP - CO_2EF \times CapTradeP$$

EQUATION E-1

Where:

Energy Portion of marginal total electricity price *LMP* (including GHG cap & trade) attributable to power plant fuel and operations, and not attributable to cap & trade costs

Units: $ / MWh

LMP Real-time locational marginal price of electricity
Units: $ / MWh
Source: CAISO OASIS

CO_2EF Marginal power plant GHG emissions factor
Units: $ / MWh
Source: https://sgipsignal.com/sgipmoer/ Version 2

CapTradeP Maginal cost of compliance with the California Air Resrouces Board's cap-and-trade system.
Units: $ / MT CO2
Source: CAISO OASIS GHG allowance daily price

E.2 GHG CAP & TRADE

$$GHGcapTrade\,\frac{\$}{\mathrm{MWh}} = CO_2EF\,\frac{\mathrm{MT\ CO2}}{\mathrm{MWh}} \times CapTradeP\,\frac{\$}{\mathrm{MT\ CO2}} \times LossRate$$ **EQUATION E-2**

Where:

GHGcapTrade Portion of total CAISO locational marginal energy price (including GHG) attributable to GHG Cap & Trade
Units: $ / MWh

LossRate Electricity distribution loss factor
Value: 1.0724
Units: Dimensionless
Source: 2022 ACC, Sheet 'Losses', Cells R8:R8766

E.3 LOSSES

$$Losses\,\frac{\$}{\mathrm{MWh}} = Energy \times (LossRate - 1)$$ **EQUATION E-3**

Where:

Losses Electrical losses
Units: $ / MWh

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E.4 GHG ADDER

$$GHG_{adder}\frac{\$}{\mathrm{MWh}} = CO_2EF\frac{\mathrm{MT\ CO2}}{\mathrm{MWh}} \times GHG_{adder\_fc}\frac{\$}{\mathrm{MT\ CO2}} \times LossRate$$ **EQUATION E-4**

Where:

GHG

GHG_{adder} The non-monetized carbon price beyond the cost of cap-and-trade allowances, reflecting the cost of further reducing carbon emissions

Units: $ / MWh

GHG_{adder_fc} GHG Adder Price Forecast

Value: 2021 = 7.3544

2022 = 7.9664

Units: $ / MT CO_2

Source: 2022 ACC, Sheet 'Emissions', Cells R13:S13

E.5 GHG PORTFOLIO REBALANCING

$$GHG_{rebalancing}\frac{\$}{\mathrm{MWh}} = -CI\frac{\mathrm{MT\ CO2}}{\mathrm{MWh}} \times GHGadderP\frac{\$}{\mathrm{MT}} \times LossRate$$ **EQUATION E-5**

Where:

$GHG_{rebalancing}$ Result of utility resource plan adjustments for added distributed energy resources and achievement of annual emissions intensity targets

Units: $ / MWh

CI Allowable carbon intensity

Value: 2021 = 0.18390

2022 = 0.18404

Units: MT CO_2 / MWh

Basis: Nominal $US

Source: 2022 ACC, Sheet 'Emissions', Cells R21:S21

E.6 ANCILLARY SERVICES

$$AncillarySrvcs\frac{\$}{\mathrm{MWh}} = Energy \times ASfactor$$ **EQUATION E-6**

Where:

AncillarySrvcs Ancillary services costs

Units: $ / MWh

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ASfactor Ancillary services factor (as fraction of Wholesale Energy)

Value: 2021 = 0. 00505803

2022 = 0. 00226098

Units: Dimensionless

Source: 2022 ACC, Sheet 'AS Procurement', Cells D4:E4

E.7 METHANE LEAKAGE

$$MethaneLeakage = (CO_2EF \times GHG_{total} - CI \times GHG_{adder}) \times LeakRate \times LossRate$$ **EQUATION E-7**

Where:

MethaneLeakage Cost of methane leakage

Units: $ / MWh

LeakRate Upstream in-state methane leakage factor (as fraction of Wholesale Energy)

Value: 0.0557

Units: Dimensionless

Basis: 100-year active GWP time horizon

Source: 2022 ACC, Sheet 'Methane Leakage', Cell C4

And:

$$GHG_{total} \frac{\$}{\mathrm{MT}} = CapTradeP + GHG_{adder\_fc}$$ **EQUATION E-8**

Where:

GHG_{total} New Total GHG Value

Units: $ / MT

E.8 GENERATION, DISTRIBUTION, AND TRANSMISSION CAPACITY

The estimation of marginal costs of generation, distribution, and transmission capacity is a long-term planning undertaking that is fundamentally different from estimation of marginal costs such as Energy or Cap & Trade, for which transparent and immediate markets exist to satisfy real-time demands. As no alternatives to the ACC are readily available, values from the ACC are used for SGIP impacts evaluation.

They are not used directly however, because the values in the ACC are based on typical meteorological year weather. To align the cost values with weather actually observed during 2021-2022 the values from the ACC were rank ordered prior to merging into the SGIP data. The results was that the highest capacity costs from the ACC were assigned to the hours when actual 2021-2022 grid loads were highest.

E.9 SUMMARY

Final sources of data for evaluation of SGIP 2021-2022 electric utility marginal cost impacts are summarized in the table below.

Cost Element	**Data Sources for SGIP Impacts Evaluation**
Energy	CAISO for Energy (with GHG)
GHG Cap & Trade	CAISO GHG Allowance
GHG Adder	ACC for GHG Adder Factor
GHG Rebalancing	ACC for Carbon Intensity Factor
Ancillary Services	ACC for constants, CAISO for Energy (with GHG), WattTime for emissions
Losses	
Methane Leakage	ACC for constants, WattTime for emissions
Generation Capacity	2022 ACC Data for 2021-2022 Rank-ordered based on CAISO DLAP grid loads
Transmission Capacity	
Distribution Capacity	