SELF-GENERATION INCENTIVE PROGRAM

2020 SGIP ENERGY STORAGE IMPACT EVALUATION

Submitted to:
Pacific Gas and Electric Company
SGIP Working Group

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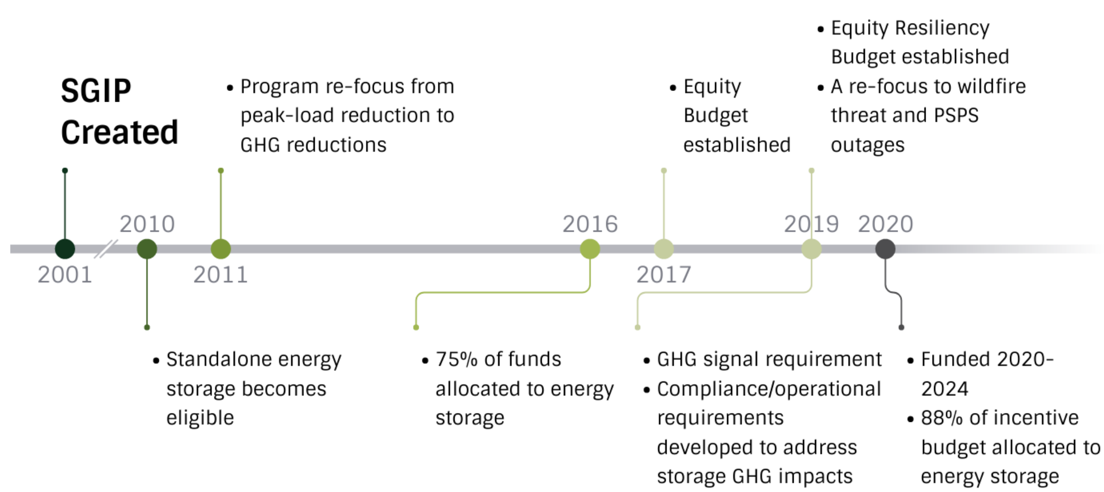
1 EXECUTIVE SUMMARY

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.

History of Energy Storage in the SGIP

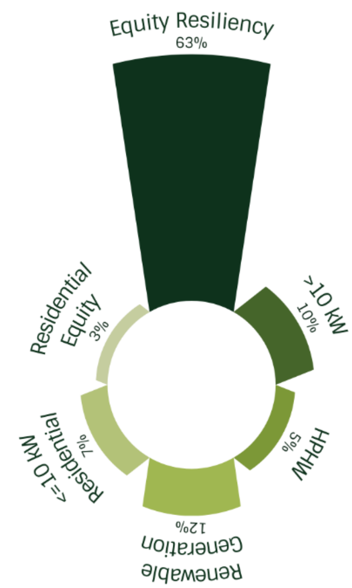
The SGIP was initially designed to provide incentives for distributed generation technologies to help address peak electricity problems in California. The program has been revised and extended multiple times since 2001, with eligibility requirements, program administration and incentive levels all changing over time. Over the years, the program focus has transitioned from peak-load reduction to greenhouse gas (GHG) reductions as climate change has moved to the forefront of statewide public policy. Figure 1-1 presents a brief history of energy storage in the SGIP.

FIGURE 1-1: HISTORY OF ENERGY STORAGE IN THE SGIP



In 2016, 75% of the SGIP budget was allocated to energy storage and the program began experiencing a significant increase in participation. Standalone energy storage was the predominant configuration in the program from its nascent years, but new budget categories with differing incentive levels allowed newer, more sophisticated energy storage configurations access into the program across multiple sectors. After annual impact evaluations revealed that storage behavior was leading to increases in GHG emissions, the SGIP adopted GHG emission reduction requirements and developed compliance and operational requirements for project developers. More recently, the program has re-focused to equity and customer resiliency as wildfire threats have compelled utilities to exercise their authority to carry out public safety power shutoffs (PSPS).

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. In previous years the 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, primarily in the equity resiliency budget category. Most of the storage budget (63% of the total SGIP budget) is allocated to this newly created budget category with incentives reaching $1 per watt-hour (Wh) of capacity. The remainder of the budget was carved out for other storage customer sectors, heat pump hot water heaters (HPHW) and renewable generation technologies (inset figure).



Measurement and Evaluation Plan

To help measure and evaluate the progress and impacts of the SGIP, the CPUC has directed the PAs to develop measurement and evaluation (M&E) plans. The most recent M&E plan was developed for program years (PY) 2016-2020. The M&E plan develops key performance metrics and program requirements, many of which are measured and tracked through impact evaluations. These impact evaluations serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet its goals. The plan calls for several metrics to be reported at the program level. The M&E plan also called for annual impact evaluations that are focused specifically on energy storage. At the time, energy storage projects represented 75% of all SGIP reservation funding, so annual evaluations were thought to provide stakeholders and decision-makers with more regular updates on how these technologies were performing. ***The purpose of this study is to satisfy the requirements of the M&E plan for 2020 and assess the ability of storage technologies to meet SGIP objectives to provide environmental benefits, improve operations of the grid, and achieve market transformation.***

Performance Metrics and High-Level Evaluation Findings

Figure 1-2 presents several of the performance metrics Verdant evaluated to fulfill the requirements set forth in the M&E plan along with some high-level findings, by customer sector. These findings are summarized below and discussed in more detail throughout this report.

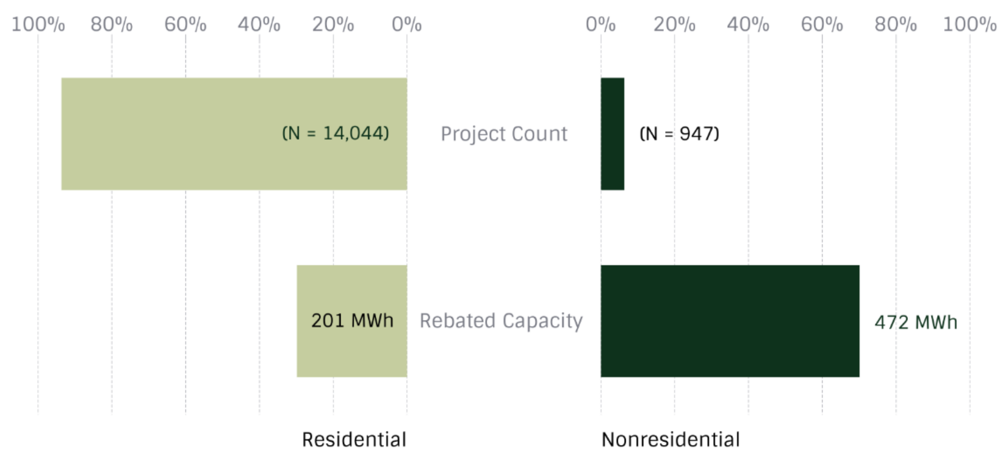
FIGURE 1-2: PERFORMACE METRICS AND EVALUATION FINDINGS

Metric	Nonresidential Findings	Residential Findings
Observed Performance Impacts		
• Roundtrip efficiencies (RTE) • Capacity Factors • Discharge Cycles	• 80% RTE for nonresidential systems • 6% capacity factor • 126 annual cycles	• 86% RTE for residential systems • 6% capacity factor • 130 annual cycles
Observed Customer Impacts		
• Customer peak demand impacts • Customer on-peak time-of-use arbitrage • Customer bill savings • Storage behavior where paired with on-site PV	• Nonresidential customers are reducing noncoincident peak demand and **realizing demand savings** ($/kW) on their bill • They are incurring increased energy charges ($/kWh) • Demand charge savings greater than energy charge increases • Storage **paired with PV is charging from excess PV generation**	• Residential customers are realizing **bill savings from TOU energy arbitrage and solar self-consumption** • Most savings come during summer periods when systems are utilized more often and on-peak energy price differentials are highest • Storage **paired with PV is charging from excess PV generation**
Observed CAISO and Grid Impacts		
• Storage impacts throughout top CAISO peak hours • Differentiated between CAISO gross peak and net peak hours	• Nonresidential systems are **discharging throughout both CAISO net and gross top hours** • Differences by faciilty – more significant discharge throughout net peak hours for primary/secondary schools	• Residential systems are **discharging throughout both CAISO net and gross top hours** • Differences by project developer and system manufacturer
Observed Environmental Impacts		
• Storage charge and discharge behavior in relation to marginal GHG emissions • Calculate kilograms (kg) / capacity kWh increases (+) or reductions (-)	• Nonresidential systems, on average, are **increasing emissions** as a fleet (1.3 kg/kWh) • Emission **increases are much less than previous evaluations** • **Systems paired with PV are reducing emissions** – most prominently in primary/secondary schools • Systems utilized more often are better equipped to reduce emissions	• Residential systems are **decreasing emissions** as a fleet (-11.0 kg/kWh) • Consistent with previous evaluations, but in greater magnitudes • Almost all residential systems are paired with PV, especially those installed in the past four years
Observed Utility Avoided Cost Impacts		
• Avoided utility cost using the 2021 Avoided Cost Calculator • Overall avoided marginal costs and by category (generation, T&D, energy, etc)	• Nonresidential system behavior provided an **avoided cost benefit to all IOUs** • Most savings realized in a few very capacity constrained hours in late summer	• Residential storage behavior provided an avoided cost benefit to all IOUs • Again, **savings realized most significantly throughout specific capacity constrained hours**
Observed Customer Reliability Impacts		
• Quantify storage behavior throughout public safety power shutoff (PSPS) events	• Very few sampled nonresidential systems experienced PSPS events	• Residential storage is **providing resiliency to customers** • We observe some reductions in household consumption throughout events, but **solar + storage allows customers to ride out multi-day events** • We observe a **reduction in PV output throughout events**

Studied Population

The energy storage population subject to evaluation represents all projects (cumulative) which have received an upfront SGIP incentive from the inception of the program through December 31, 2020. By the end of 2020, the SGIP provided incentives for **14,991 projects**[1] representing roughly **673 MWh of rebated capacity**. As of December 31, 2020, all but three are electrochemical (battery) energy storage technologies.[2] Figure 1-3 shows the breakdown in sector by project count and rebated capacity. While residential systems subject to evaluation in 2020 represent the vast majority by project count (94%), the majority of the SGIP storage rebated capacity (70%) is installed at nonresidential customer sites.

FIGURE 1-3: PROJECT COUNT AND REBATED CAPACITY BY CUSTOMER SECTOR



Evaluation Approach

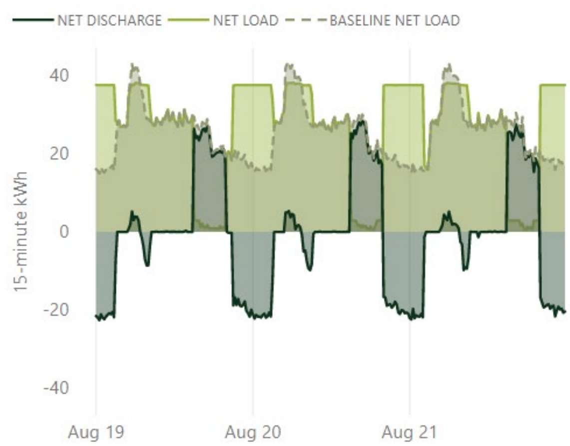
This evaluation examines the performance of energy storage systems by quantifying the observed impacts of systems throughout 2020. Verdant collected metered storage charge and discharge data and customer electric load profiles from residential and nonresidential SGIP participants. Some of the impacts and metrics discussed in this report are developed to better understand the efficiency of the system or how well utilized the system was throughout the year. These metrics, such as the roundtrip efficiency or capacity factor, can be calculated directly from storage charge and discharge data.

Other impacts, such as customer bill impacts, involve making assumptions about a customer's consumption had they not installed the energy storage system. Quantifying these impacts requires developing counterfactuals – how would a customer service load in a baseline where no storage exists – and comparing that baseline to what was observed. The latter value is metered and can be directly

1 This represents an increase of roughly 70% in project count since 2019 alone.

2 Three thermal energy storage technologies have also received incentives.

measured. The former value is a calculated one – taking the metered net load with storage and subtracting out the influence of storage. In other words, Verdant assumes no behavioral change resulting from the customer's installation of battery storage.



If a customer is discharging their battery (+), they are reducing the need to service load from the grid. When a customer is charging the battery (-), they are increasing their load relative to a baseline of no storage (inset figure). If the emissions *avoided* during storage discharge are greater than the emission *increases* during storage charging, then the customer can realize GHG reductions. Furthermore, if a storage system was discharging to service load at a home, it was reducing the power needed from the grid at that moment. A customer could realize bill savings relative to the counterfactual if discharging occurred during high-priced hours and charging occurred during lower-priced hours.[3]

Evaluation Findings, Conclusions and Recommendations

This report is the fourth annual evaluation of energy storage systems rebated by the SGIP. The quantity and variety of storage systems that participate in SGIP has changed considerably since the first SGIP energy storage evaluation report covering calendar year 2017. Changing eligibility rules, evolving retail rates, and the availability of a GHG signal have all impacted the operation of SGIP energy storage systems. Annual SGIP evaluations provide an important feedback mechanism to assess the effectiveness of policy changes and track how storage dispatch is changing in response to technology improvements.

The nonresidential results of this evaluation are largely consistent with observations from the 2019 SGIP energy storage evaluation. However, a new fleet of nonresidential systems paired with solar PV generators is providing benefits throughout the past two evaluations that were previously unrealized. Trends that were evident with residential systems in 2019 have continued into 2020, and with a much larger fleet of residential systems in the SGIP population, the overall impacts have increased substantially.

Below we present key findings and conclusions from this evaluation based on metered data collected from a representative sample of residential and nonresidential customers (Section 4). Where possible, we also

3 This is referred to as energy arbitrage. Billed energy savings are realized when the total dollars saved from discharging exceeds the total dollars incurred from charging the system, along with any energy losses associated with roundtrip efficiency.

provide considerations and recommendations that could inform future policy and program design. Many of these findings reveal how storage behavior during 2020 was meeting or falling short of SGIP goals and objectives. In-depth findings and analyses can be found in Section 5 of this report.

Findings: Greenhouse Gas Emissions

Overall, SGIP storage systems operating during 2020 contributed to a net reduction in GHG for the first time in program history, but nonresidential systems continue to be net emitters, although to a lesser extent than previous evaluation years. Figure 1-4 plots the decrease (-) or increase (+) in emissions for each customer sector – along with the total program impact – from the past three evaluations. We observed an increase in both sectors in 2018 and a total net increase in 2019, even though residential systems – as a sector – reduced emissions. In 2020, the increased residential reductions combined with lower nonresidential increases, contributed to a program level reduction of 1,547 metric tons of GHG. During 2020, residential systems decreased GHG emissions by 11.0 kilograms for each kWh of capacity and nonresidential systems increased emissions by roughly 1.3 kilograms for each kWh of capacity.

FIGURE 1-4: GHG EMISSIONS BY EVALUATION YEAR AND CUSTOMER SECTOR

Storage systems paired with on-site PV realized far more significant GHG emissions reductions than standalone energy storage systems. The reasons for the program-level emission reductions are multi-faceted, but the increased share of storage systems paired with PV is a significant factor. Residential and nonresidential storage systems paired with on-site solar generation are charging almost exclusively from on-site solar. Residential customers who claim the Investment Tax Credit (ITC) for solar and storage are required to charge their system exclusively from solar generation. Nonresidential customers are required to charge at least 75% from solar. We observed residential systems charging from solar 99.8% of the time and nonresidential systems at 96.0% of the time. Morning PV generating hours align well with periods of low grid-level marginal emissions, so charging during this period provides systems a greater opportunity to reduce overall emissions throughout the year. Roughly 50% of all nonresidential projects were paired or co-located with solar PV in 2020. We observed 68% of those sampled nonresidential systems reducing GHG emissions, while 16% of standalone systems reduced emissions in 2020. Almost all sampled residential systems are paired with on-site PV, with over 90% of systems reducing GHG emissions in 2020.

Conclusions and Recommendations: Greenhouse Gas Emissions

The improvement in GHG emissions from the residential systems suggests that the sector has turned a corner since being a net emitter during 2018. The current population of storage systems is generally behaving as expected – charging during solar PV generation hours (and low grid marginal emissions hours) to maximize the federal ITC. The ITC is set to expire in 2024, so it's important that **storage developers continue to offer a PV self-consumption operating mode even if the tax credit expires and is not renewed by Congress.**

SGIP participants claiming the ITC for battery storage are required to charge from PV for the first five years. It will be important to **continue monitoring and studying customers beyond this five-year period** to determine if there is a significant behavior change that is impacting program GHG and avoided cost benefits. Finally, emerging technologies from **new manufacturers should be closely evaluated to ensure their GHG emissions profile mirrors what we have seen** from the current cohort of systems.

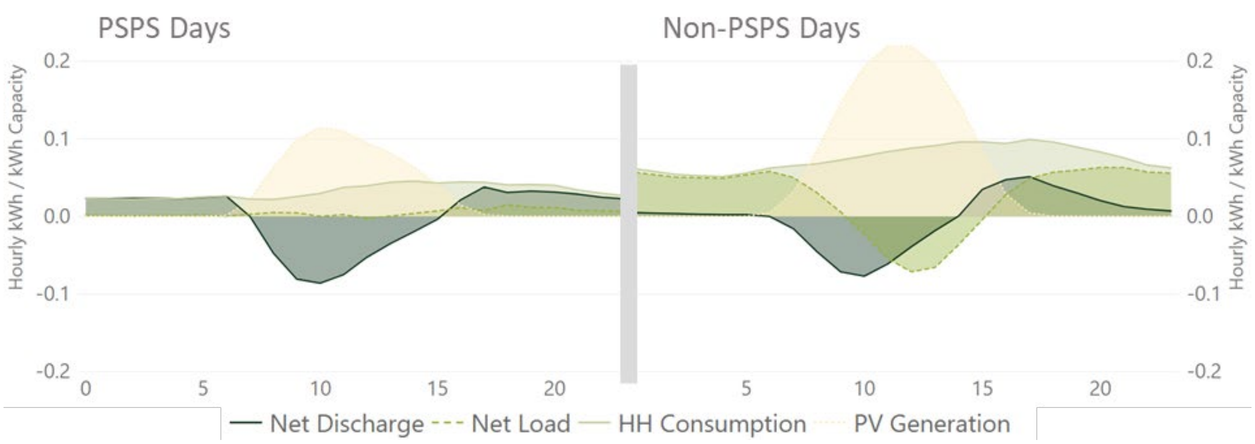
Nonresidential projects as a group remain overall GHG emitters through 2020. Projects rebated recently and paired with solar PV have achieved substantial GHG emissions reductions which, in turn, have driven average nonresidential emissions down. D. 19-08-001 also adopted GHG emission reduction requirements and developed compliance and operational pathways for project developers to achieve GHG reductions. These pathways include: 1) meeting the program's round-trip efficiency and capacity factor requirements set forth at the time of project approval, 2) enrolling in demand response (DR) programs or an approved storage rate, or 3) following the GHG signal. Given the timing of this evaluation, it is too early to tell if any of these pathways are more advantageous as a means of driving projects towards GHG reductions than the others. **We recommend that the 2021 Storage Impact Evaluation explore differences across these pathways** to provide more actionable and grounded recommendations for future GHG emissions reduction performance and compliance.

Moving forward, we reiterate the increased benefit observed from storage projects that align their charging hours with on-site solar PV generation. The nonresidential market has naturally gravitated towards paired systems (rather than standalone storage), perhaps due to the increased emphasis on resiliency. We believe it is premature and potentially heavy-handed regulation to require all nonresidential storage projects to be paired with PV going forward. However, **standalone projects should face higher levels of scrutiny during the application process** to ensure that their charge/discharge behavior is conducive to GHG reductions. Information from future impact evaluations regarding the efficacy of **GHG reduction pathways should be incorporated into future program eligibility requirements**.

Findings: Residential Customer Resiliency and PSPS Events

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. Figure 1-5 provides the average hourly net discharge, net load, household consumption and PV generation for customers experiencing PSPS outages across all IOUs and those same impacts on non-outage weekdays during the same season. We observe a reduction in both PV generation[4] and household consumption during outages, but an increase in storage utilization. The paired solar and storage allow affected customers to maintain some level of reliability throughout grid de-energization events.

FIGURE 1-5: AVERAGE HOURLY IMPACTS FOR CUSTOMERS ON PSPS DAYS AND NON-EVENT DAYS



Standalone systems provide very limited resiliency benefits and customers without paired solar PV typically exhibit drastically reduced consumption during outages. For customers with paired on-site solar we observe much higher levels of consumption during the outage, closer to typical household consumption. We also observe a greater magnitude of charging from some energy storage systems prior to a PSPS event, likely in anticipation of the outage, and deep charging again once the power is restored. Customers experiencing PSPS outages are provided updates and alerts from their utility with estimated

[4] We observe a reduction in peak and overall solar PV generation throughout the PSPS events and while islanding 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.

power shutoff and restoration times. In response to those alerts customers will charge outside of on-site solar generating hours, which uses grid energy.

Conclusions and Recommendations: Residential Customer Resiliency and PSPS Events

We recommend continued evaluation of battery storage performance before, during, and after outages/PSPS events to better understand how both standalone and paired PV systems dispatch during these events. As customers increasingly rely on battery storage for reliability during outages and new products enter the market, it is important to **provide public information on the abilities of these technologies to deliver resiliency benefits, especially for customers with underlying medical conditions**. Program administrators and utilities **must prepare for a future where there are more PSPS outages** extending earlier and later into the fire season, more customers affected by these outages, and more customers with BTM energy storage resources installed, all responding to these events in a similar manner. **Decision makers should consider the reduced resiliency value of standalone storage relative to the greater resiliency provided by storage paired with solar PV.**

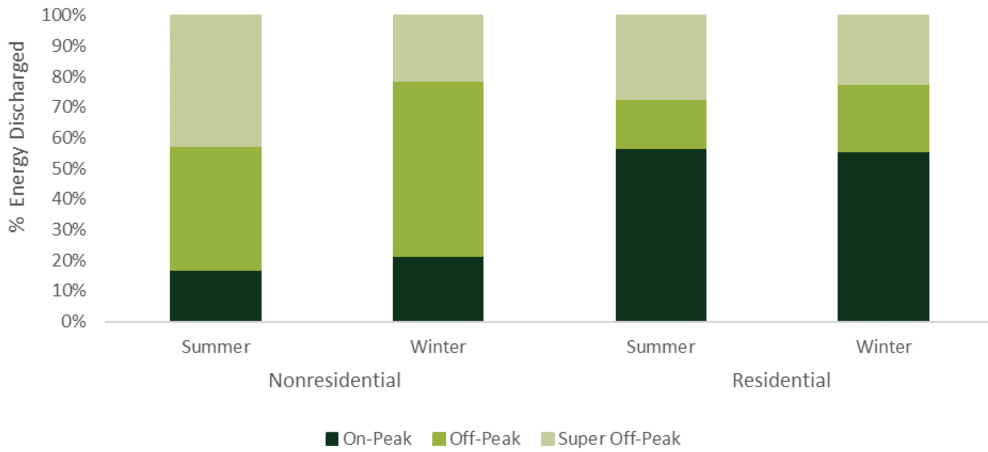
Findings: Storage Utilization and Grid Needs

Residential storage systems are discharging a greater percentage of energy – but not all energy – throughout on-peak bill periods and nonresidential systems are discharging a greater percentage of energy outside the on-peak period. We observe residential systems discharging 56% of energy and nonresidential systems discharging 16% of energy throughout summer on-peak hours when customers are charged more for electricity (Figure 1-6). 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 incentivized to discharge during the on-peak period.

Reducing the energy portion of bills may not be the key driver of storage behavior for all customers, especially for nonresidential customers who are utilizing their storage systems for demand charge reductions. Facility peak demand may not coincide with utility on-peak periods, so a customer may prioritize demand charge reduction at the expense of time-of-use (TOU) energy arbitrage. During on-peak periods, residential systems are utilizing roughly 37% of available energy, while nonresidential systems are using 14%. Customers not on a TOU rate[5] are discharging, on average, 36% of available energy throughout the day.

[5] While the SGIP now requires new customers be on an eligible TOU rate, we observe customers who applied to the program prior to this requirement still on a tiered volumetric rate. In 2020, this represented roughly 12% of all sampled residential projects.

FIGURE 1-6: OBSERVED PERCENT DISCHARGE KWH BY TOU PERIOD AND CUSTOMER SECTOR



Both customer sectors are providing a benefit to the electricity system during the CAISO peak hour and maintain that benefit across the top 200 peak system hours, however there is significant untapped potential to provide grid benefits. 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 (MW) and 2) the net peak – when overall demand minus renewable supply sources is reaching peak generation. The total program energy capacity in 2020 was roughly 673 MWh. Residential and nonresidential systems discharged roughly 7.2 MWh during the top gross peak hour, and 10.2 MWh during the top net peak hour. 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 $2.9 million avoided cost benefit across utilities, with most benefits occurring throughout a few capacity-constrained hours in the late summer.

We observed residential and nonresidential systems not discharging the total capacity of the system regularly and many residential customers are limiting discharge to maintain net zero load – not exporting. This finding is intuitive – if customers are already abiding by SGIP rules for 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, or warranty perspective. However, **there is considerable untapped potential for Resource Adequacy (RA), Emergency Load Reduction Program (ELRP), and other grid benefits if extra battery capacity is deployed or co-optimized with grid needs and/or price signals.**

Conclusions and Recommendations: Storage Utilization and Grid Needs

If there is desire to increase residential BTM storage utilization, **we recommend investigating the technical, behavioral, and policy challenges that might limit battery discharge to no export** (i.e., only reducing imports to zero). For a significant number of systems, peak hour capacity factors are low primarily because the battery discharge is constrained by customer load. If the choice to not export is non-technical and wouldn't require system re-design or retrofit, then **the CPUC and Program Administrators should better understand why customers would not export.** Having said that, the NEM successor tariff, as currently proposed, would also disincentivize customers from exporting at all since export compensation will be greatly reduced. **NEM policy and SGIP policy should be aligned to advance CPUC policy priorities in a coordinated fashion and conflicts between the two programs should be eliminated**.

We continue to observe a lack of granular price signals to align storage discharge with the most critical hours of grid needs. Time of use periods are effective at generally shifting load but are too broad (typically 4-5 hours long) to target the most grid constrained hours (e.g., the CAISO top 200 net peak load hours). **Programs like the Emergency Load Reduction Program (ELRP) aim to incentivize load reduction during these hours**, **however increased awareness or perhaps default enrollment is needed** to increase the participation of SGIP customers in this program. Other solutions, like requiring **participation in critical peak pricing (CPP) programs**, should be explored.

We also observe some developers discharging a significant percentage of capacity from 4-5 pm every weekday throughout summer – *with* storage export. This is a simple algorithm for the battery to administer but doesn't lead to the most optimal use of the system from a GHG or grid needs perspective. Discharging a few hours later or over a longer duration of the on-peak period could provide more utility benefits and GHG reductions – as grid-level net load ramps – with bill savings largely unchanged. Furthermore, a few thousand systems all discharging at the same time may not create any disruptions on the distribution system, but tens of thousands might. The CPUC and PAs should **continue to track and understand behavior** like this and, perhaps, **encourage lower magnitude power discharge over longer durations or compel the developer to stagger the timing of discharge across their fleet of systems**.

Findings: Data Collection Requirements Across Developers and Manufacturers

Many project developers, particularly smaller ones, had difficulties providing the data that are necessary to complete this evaluation. Because of the requirement that GHG impacts be reported for each developer's fleet of storage projects, Verdant had to request data directly from dozens of distinct project developers (as opposed to simply working with manufacturers or the largest developers). Some smaller developers are unaware of the M&E requirements associated with SGIP participation or they are willing to provide the data, but don't have the expertise or subject matter knowledge to query storage metered data using an Application Programming Interface (API). Verdant has developed a tool by which customers can access storage system data across the API, which makes the data transfer much less onerous and time-consuming for developers. However, even with these tools, not all developers could provide the necessary data.

Conclusions and Recommendations: Data Collection Requirements Across Developers and Manufacturers

PAs should help communicate the needs of the evaluator throughout the application process and at the outset of the evaluation so reporting timelines are not at risk. The M&E evaluator **could provide voluntary training to smaller developers** at the outset of the evaluation to help them better understand how to access the API. Otherwise, more cost prohibitive and duplicative options are available, like installing metering equipment at customer homes and businesses. Furthermore, **the evaluator could be invited to present at quarterly forums and other program-related events**, so developers are more directly aware of their role in evaluating the program.

Findings: Storage Decommissioning

Verdant has continued to observe more and more storage systems being decommissioned prior to their full permanency period (or 10-year warranty). Verdant has identified 73 nonresidential systems which have been decommissioned within the program. While this represents a small percentage within the program now, as time moves forward, this might grow to a larger percentage of program capacity.

Conclusions and Recommendations: Storage Decommissioning

PAs and evaluators should **continue to track decommissioning of SGIP rebated energy storage technologies** and gather more information on why these systems were removed prior to their full permanency or effective useful life. **Survival analysis methods**, which help determine project survival probabilities and expected operational longevity, **could also shed light on trends** in decommissioning and help forecast lifecycle operations for rebated systems.

Findings: Developer and Manufacturer Data Acquisition Systems

Developers and manufacturers who meter storage charge/discharge, but also net load and PV generation data, enable a greater number of dispatch algorithms and allow the evaluator to better understand and quantify behind-the-meter (BTM) consumption. Equipment that meters storage, consumption, and PV generation allows the battery to understand when load is going negative (exporting) or positive (importing). This allows for more sophisticated use cases like self-consumption and the ability of customers to maintain zero net load throughout the day. In contrast, we observe that projects that don't meter consumption are limited in their capabilities and may struggle to provide increased functionality going forward.

Conclusions and Recommendations: Developer and Manufacturer Data Acquisition Systems

The SGIP should consider offering customers with **additional education materials** on different available storage products to **help inform their decision-making process** and to provide them with a suite of

benefits and limitations of different technologies and configurations. This may be increasingly relevant as retail rates become more dynamic and NEM policy evolves.

Findings Only: Customer Bill Impacts

Energy storage systems deliver bill savings. One of the key influences on storage utilization and efficiency is how the system is being managed to provide customer benefits. Nonresidential customers, on average, realized total annual bill savings exceeding $9 per system capacity kWh. These savings come predominantly from demand charge reductions. Residential customers realized annual bill savings of roughly $4 per system capacity kWh. However, annual bill impacts exhibit substantial variability, with bill savings as high as $65 per rebated kWh[6] to as low as -$28 per rebated kWh (a bill increase).

Findings Only: Nonresidential Customer Resiliency and PSPS Events

Nonresidential customers are eligible for Equity Resiliency Budget incentives if they're located in Tier 2 and Tier 3 HFTDs and provide critical infrastructure to a community. However, no nonresidential customers received incentives from the ERB in 2020. The program's focus on equity and resiliency is nascent, so we would expect to see more activity in future years, especially if nonresidential facilities apply to and garner incentives through the ERB. Utilizing community centers, schools, and other public facilities accessible to vulnerable communities will require coordination across a variety of actors and stakeholders across multiple jurisdictions – local governments, transportation departments, and community-based organizations (CBOs) – among others.

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[6] A customer installing a 13-kWh system and saving $65 per kWh (the maximum observed residential bill savings value) could realize roughly $850 in billed savings for that year, relative to a baseline of no storage. That represents roughly 5% to 15% of system cost, depending on several factors – the price of the system, on-peak versus off-peak price differentials, storage use case and utilization, etc.

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.

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[7], the program has evolved since 2001, with eligibility requirements, program administration and incentive levels all changing over time. Approval of Assembly Bill (AB) 2778[8] 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[9] shifted the program's focus from peak-load reduction to greenhouse gas reductions.

2.1 HISTORY OF ENERGY STORAGE IN THE SGIP

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.[10] In 2011, standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – were made eligible for incentives.[11] In 2011, the CPUC issued Decision (D.) 11-09-15, which added SGIP eligibility requirements based upon greenhouse gas (GHG) reductions. This was followed by D. 16-06-055 in 2016, which, among

7 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

8 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

9 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

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

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

other changes, revised how the SGIP is administered.[12] 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.[13]

More recently, the CPUC issued D. 19-08-001 approving greenhouse gas emission reduction requirements for the SGIP storage budget.[14] 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”.[15]

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 resilience budget.[16] 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.

Most recently, in January of 2020, the CPUC issued D. 20-01-021.[17] The decision authorized the collection of ratepayer funds totaling $166 million dollars per year from 2020 to 2024 across the four program administrators. This decision also increased the financial incentive budget for energy storage technologies

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[12] CPUC Decision D.11-00-055. June 23, 2016. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=163928075

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

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

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

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

[17] 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 ENERGY STORAGE IN 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
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 greenhouse gas (GHG) signal ▪ Defines compliance pathways and operational requirements for "new" and "legacy" projects and "developer fleets" ▪ 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 from 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

2.2 CURRENT STATUS OF ENERGY STORAGE IN THE SGIP

As in previous years, the SGIP budget in 2020 continues to heavily emphasize storage technologies. The overall share of the SGIP budget reserved for storage technologies increased from 75% in 2017 to 88% in 2020. This coincides with several changes made to the SGIP budget allocation process and program eligibility requirements in 2020. In previous program years the 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, primarily in the equity resiliency budget category. The SGIP energy storage budget is broken out into five categories: Large-Scale, Small

Residential, Residential Equity, Equity Resiliency and Heat Pump Water Heaters.[18] Most of the energy storage budget (63% of the overall 2020-2024 budget) is allocated to the newly created Equity Resiliency budget category. The remaining 12% of budget is carved out for renewable generation technologies. Table 2-2 presents the overall distribution of budget allocation along with a brief description of the eight budget categories.

TABLE 2-2: DESCRIPTION OF PY 2020 – 2024 BUDGET CATEGORIES

Budget Category	Budget Allocation	Brief Budget Category Description
Equity Resiliency	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 percent fueled with renewable biogas.
>10 kW Large-Scale Storage	10%	▪ Open to nonresidential projects or residential projects greater than 10 kW.
<=10 kW Small Residential Storage	7%	▪ Open to residential projects less than or equal to 10 kW.
Heat Pump Water Heaters	5%	▪ $4 million in accumulated unused incentive funds were transferred to this category ▪ As of December 2020, this budget category has not opened. Funds for this category are on hold pending a CPUC decision on how to structure the incentives.[19]
Residential Equity	3%	▪ Open to single-family low-income housing or multi-family low-income housing, regardless of project size.
Nonresidential Equity	n/a	▪ Open to local, state, or tribal government agencies, educational institutions, non-profit organizations or small businesses. ▪ The project site must be in or provide service to a disadvantaged community.
San Joaquin Valley Pilot	n/a	▪ Open to residential and nonresidential storage projects located in 11 San Joaquin Valley disadvantaged communities

[18] There are two additional budget categories – Nonresidential equity budget and the San Joaquin Valley Pilot (SJVPP). As per the SGIP 2020 V9 Handbook, the authorized collection for nonresidential equity storage has been suspended once existing carryover is exhausted. The SJVPP has $10 million set aside from SCE and PG&E's unused nonresidential equity budget.

[19] For more information see the SGIP HPWH Staff Proposal (April 19, 2021): https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442468802

2.3 REPORT PURPOSE

As discussed previously, SGIP eligibility requirements and incentive levels have changed over time in alignment with California's evolving energy landscape. To help measure and evaluate the progress and impacts of the SGIP, the CPUC has directed the program administrators to develop measurement and evaluation (M&E) plans. The most recent M&E plan was developed for PY 2016-2020 in response to requirements set forth in D. 16-06-055.[20] The M&E plan develops key performance metrics and program requirements, many of which are measured and tracked through impact evaluations. These impact evaluations serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet its goals. The plan calls for several metrics to be reported at the program level. These include quantifying:

- Reductions or increases in GHG and criteria air pollutant emissions.
- Total energy reductions (kWh) and total aggregate noncoincident customer peak demand (kW).
- Utilization of SGIP distributed energy resources (DERs) and system efficiencies (roundtrip efficiency (RTE)).
- Value of electric transmission and distribution (T&D) system measured in the avoided costs of T&D upgrades and replacements.
- The ability of SGIP DERs to improve customer onsite electricity reliability.

The M&E plan also called for the creation of a series of annual impact evaluations that are focused specifically on energy storage. At the time, energy storage projects represented 75% of all SGIP reservation funding, so annual evaluations were thought to provide stakeholders and decision-makers with more regular and real time updates on how these DERs were performing. Along with the metrics detailed above, the M&E plan calls for several metrics to be reported for SGIP energy storage systems. These include quantifying:

- Net GHG emissions of energy storage systems as a class (i.e., all systems combined) and net GHG emissions differentiated between residential and nonresidential systems, and between systems paired with renewable generation and non-paired systems.
- Timing and duration of charge and discharge on an average basis and identification of groups of storage systems exhibiting certain trends in the timing of charge and discharge.
- In accord with Public Utilities Code § 379.6(I)(6), quantify any contribution of energy storage projects to grid services where that storage substituted for and replaced planned investment into grid services.

[20] At the time the plan was approved, the SGIP was set to expire in 2020. SB 700 extended the SGIP from 2020 to 2025. Currently, the CPUC, in consultation with the PAs, is developing an M&E plan which covers PY 2021-2025.

These requirements were developed from the PY 2016–2020 M&E plan, so previous evaluations have focused specifically on these metrics. However, additional requirements have been developed in response to CPUC decisions set forth since the plan was first introduced. These requirements are new to this 2020 impact evaluation and include metrics like quantifying developer fleet GHG emissions based on when they applied and were incented through the SGIP. Furthermore, the creation of the equity resiliency budget in 2020, and the increased frequency of PSPS outages, has added additional performance metrics and research objectives to the current evaluation that were limited in scope in previous years.

Overall, the purpose of this study is to satisfy the requirements of the M&E plan for 2020 and assess the ability of energy storage technologies to meet SGIP objectives. As the M&E plan calls for annual impact evaluations, this study is a continuation of the work performed in the *2019 SGIP Energy Storage Impact Evaluation Report*. All systems included in 2019 are included in this study, in addition to the systems that received incentive payments during 2020.

2.4 GOALS AND OBJECTIVES

The primary objective of this study is to evaluate the performance of energy storage systems rebated through the SGIP and operating during calendar year 2020. Verdant analyzed several different observed impact metrics and compared those metrics to anticipated ones. The specific objectives of the evaluation are listed below and are discussed in more detail in Section 5.

- Observed Performance Impacts
  - Calculate roundtrip efficiencies (RTEs), capacity factors (CF), number of discharge cycles
  - Compare system performance in 2020 to performance in 2019
- Observed Customer Impacts
  - Analyze and/or quantify charge/discharge behavior in relation to customer noncoincident peak demand, time-of-use (TOU) schedules and monthly bill savings
  - Analyze the behavior of storage systems paired or co-located with on-site generation technologies like solar photovoltaic systems (PV)
- Observed CAISO and IOU System Impacts
  - Analyze and quantify charge/discharge behavior in relation to CAISO system gross and net load and utility coincident peak demand
- Observed Environmental Impacts
  - Analyze and quantify the timing of charge/discharge behavior in relation to marginal greenhouse gas (GHG) emissions

- Developer Fleet GHG emissions reporting
- Provide GHG kilograms per kWh of capacity emissions data for legacy developer fleets[21]

- Observed Utility Marginal Cost Impacts
  - Analyze charge/discharge behavior in relation to utility marginal costs as quantified in the CPUC 2021 Avoided Cost Calculator
- Observed System Behavior During Public Safety Power Shutoff (PSPS) Events
  - Analyze and quantify how storage systems are being utilized for customers affected by PSPS events during high wildfire risk periods
- Energy Storage Program Level Impacts
  - Combine project-specific sample data from the objectives above to *quantify the magnitude* of total population level impacts for SGIP energy storage systems operating throughout 2020

2.5 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 4). Sources of data used in this evaluation include:

- The SGIP Statewide Project Database – contains project characterization information such as rebated 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 storage charge/discharge data
  - Data for systems subject to PBI data collection rules were downloaded from the Statewide Project Database
  - Data for a sample of all systems (regardless of size) were requested and received from project developers
- Metered customer interval load and tariff information were requested and received from the electric IOUs and project developers, where available

[21] Section 4 discusses and defines developers, fleets and legacy projects versus new projects in more detail.

- Marginal emissions data were collected from the GHG signal provider, WattTime[22]
- Utility avoided cost information were collected from the CPUC 2021 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 5. Details on the data integrity and quality control (QC) methods are provided in Appendix B.

2.6 REPORT ORGANIZATION

This report is organized into five sections and three 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 more granular characterization of the energy storage population
- Section 4 details the sampling approach used to develop population impacts
- Section 5 characterizes the metered sample and presents the observed and overall program impacts
- Appendix A describes how customer bill impacts were estimated
- Appendix B presents the sources of data used in this evaluation and the quality control exercises performed to verify storage data
- Appendix C provides additional figures and tables that were not included in the main body of the report

22 https://sgipsignal.com/

3 STUDIED POPULATION

The 2020 SGIP energy storage population is collected from the most recent version of the statewide project list and downloaded at www.selfgenca.com. This dataset provides the current listing of all projects that have applied to the program, have a performance-based incentive (PBI) payment structure, have been issued incentives, and contains important information, including project developer name, system size, system location, budget category, 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, 2020, *and* 2) having fully qualified state of "Payment Complete" or "Payment PBI in Process" *and* 3) where equipment type is electrochemical, mechanical or thermal storage.

3.1 EVALUATED SGIP ENERGY STORAGE POPULATION

Figure 3-1 and Figure 3-2 present the growth in SGIP storage rebated capacity from 2009 through 2020 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, storage 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.[23]

By the end of 2020, the SGIP provided incentives for **14,991 projects** representing roughly **673 MWh of rebated capacity**. As of December 31, 2020, all but three are electrochemical (battery) energy storage technologies.[24]

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[23] A participant may apply to the SGIP in 2020, but not receive their incentive payment until 2021. This customer would NOT be part of the population frame for this study. Incentives must be paid on or before December 31, 2020.

[24] There are three thermal energy storage technologies receiving incentives.

FIGURE 3-1: SGIP STORAGE CUMULATIVE GROWTH OVER TIME BY PROJECT COUNT

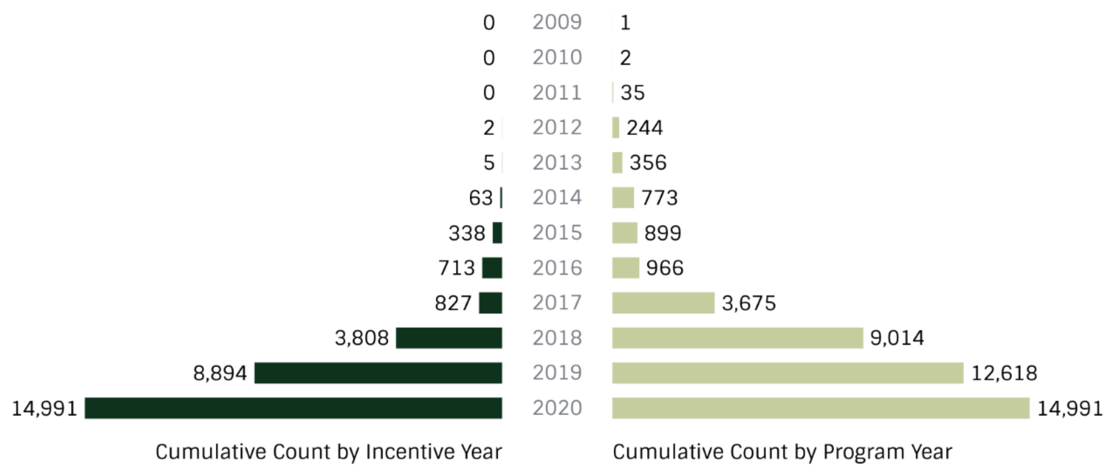
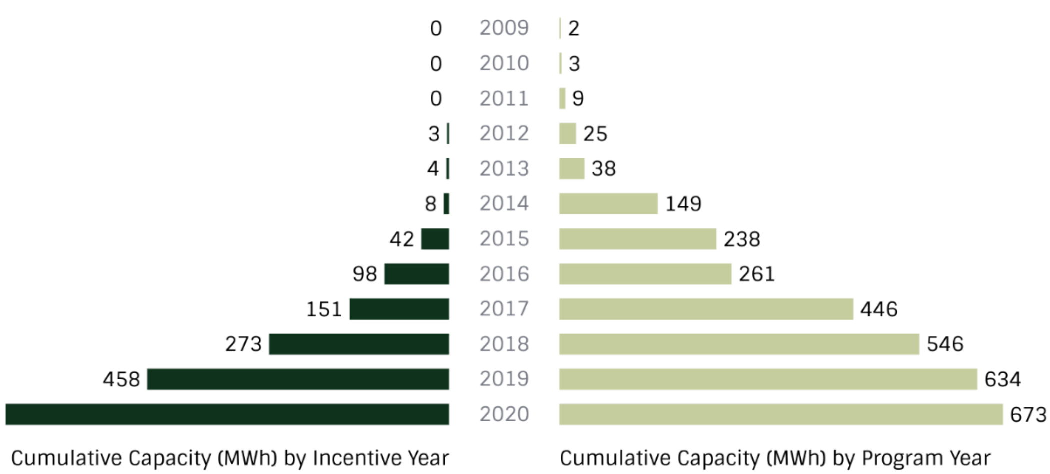


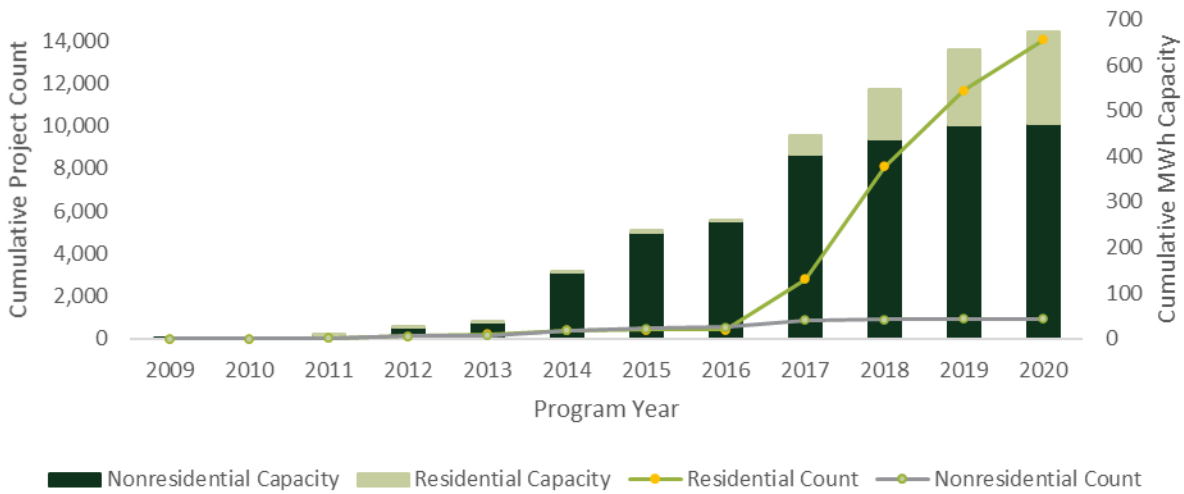
FIGURE 3-2: SGIP STORAGE CUMULATIVE GROWTH OVER TIME BY CAPACITY (MWH)



From the perspective of rebated capacity, the SGIP experienced the most significant growth in storage applications during PY 2012 – 2017. However, by project count, the program experienced the most extensive growth in storage applications during PY 2017 – 2020 because of the growth in residential participation. This dramatic increase is due, in part, to changing program eligibility requirements, administration and changing incentive levels. Other factors include declining energy storage costs, new residential storage product offerings, new time-of-use (TOU) energy rates which allow for energy arbitrage opportunities and bill savings, and an increase in the number of distinct project developers offering residential energy storage products. More recently, the budget allocation to resiliency customers has further increased the share of residential projects in the program. Nonresidential systems experienced the most significant growth in applications during PY 2012 – 2015 after standalone energy storage became eligible for incentives. Nonresidential applications have leveled out since PY 2017.

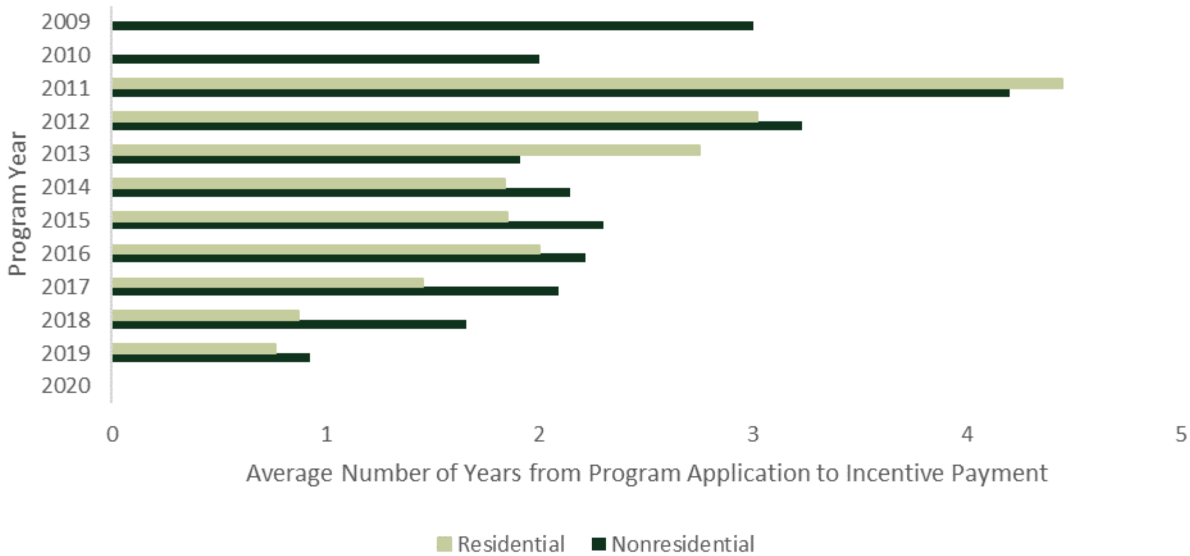
Figure 3-3 highlights these nuances where the growth in SGIP storage for nonresidential and residential participants are presented, by project count and rebated capacity across each program application year. We observe nonresidential capacity (dark green bars) increasing most substantially from 2014 through 2017. Residential participation steps up considerably beginning in PY 2017 and through PY 2020, both in terms of capacity (light green bars) and project count (thin green line with orange markers). Again, these summaries represent the year in which a customer applied to the program, rather than when they ultimately received their incentive.

FIGURE 3-3: SGIP STORAGE CUMULATIVE PROJECT COUNT AND CAPACITY (MWH) BY PROGRAM YEAR



The earlier program years saw longer lag times between program application and ultimate incentive payment. This is evident in Figure 3-4 where the average time between program application and incentive payment are presented by customer sector and the year in which a customer applied to the program. On average, the application process is longer for nonresidential customers than residential ones, but over time we observe a reduction in time spent between application filing and incentive payment for both sectors. When new budget categories are created and changes are made to the incentive structure, demand in program participation may ebb and flow in response.

FIGURE 3-4: AVERAGE TIME BETWEEN PROGRAM APPLICATION AND INCENTIVE PAYMENT



While the upfront payment year defines the population frame and the scope of systems subject to evaluation for 2020, we also present some impacts and findings by program year to provide additional insight into when customers applied to the program. This is relevant when thinking about the different program rules that apply to specific groups of projects (e.g., projects receiving incentives in PY 2020 through the new equity resiliency budget category or GHG reduction requirements for new versus legacy systems) and the timing by which customers receive incentive payments.

Table 3-1 presents the population frame by budget category pathway, customer sector and when each of those different budget categories were made available within the SGIP. Storage projects from PY 2009 – 2016 represent earlier generation technologies that were rebated prior to passage of D. 16-06-055. Average incentives per rebated capacity within this category were generally higher than for systems rebated in the subsequent large-scale storage and small residential categories. These latter categories were first subject to changes in program administration and incentive step-downs developed in response to D. 16-06-055.

While the residential equity budget was created in PY 2018, as of December 31st, 2020, only one participant has received an incentive through that budget category, along with eight customers in the nonresidential equity budget. As discussed previously, the small residential storage budget represents the greatest share of customers in the population frame. The average residential system in this category is 14 kWh. This is roughly a third of the size of systems rebated through the residential large-scale storage budget category (43 kWh) and roughly 10 kWh less than systems rebated within the newly created equity resiliency budget (24 kWh).

The original incentive rate for storage systems was set at $2.00 / Watt in PY 2009. By PY 2019, the incentive levels for energy storage had changed and were predicated on system characteristics – large storage (>10 kW), large storage claiming ITC and residential storage (<= 10 kW) – and were divided across five steps. Incentives are now calculated on a watt-hour (Wh) rather than watt basis. Incentive levels for customers in the small residential category are much less compared to those incented through the equity resiliency budget ($0.34 to $0.96 per Wh, respectively). The equity resiliency budget was set at $1.00 per Wh beginning in PY 2020, whereas the small residential incentive represents a blend across program years and budget incentive step-downs.

TABLE 3-1: SGIP STORAGE POPULATION BY BUDGET CATEGORY AND CUSTOMER SECTOR

Budget Category	Customer Sector	Project Count	Capacity (MWh)	Average Incentive ($)	Average Capacity (kWh)	$/Wh
Pre-2017 PY 2009 – PY 2016	Nonresidential	557	257	$ 231,366	461	$ 0.50
	Residential	409	4	$ 10,631	10	$ 1.04
Large-Scale Storage PY 2017 – 2020	Nonresidential	381	212	$ 93,882	557	$ 0.17
	Residential	244	10	$ 11,811	43	$ 0.28
Nonresidential Equity PY 2019 – 2020	Nonresidential	8	3	$ 91,888	415	$ 0.22
	Residential	-	-			
Residential Equity PY 2018 – 2020	Nonresidential	-	-			
	Residential	1	0	$ 7,425	22	$ 0.34
Equity Resiliency PY 2020	Nonresidential	-	-			
	Residential	153	4	$ 22,992	24	$ 0.96
Small Residential PY 2017 – 2020	Nonresidential	-	-			
	Residential	13,238	183	$ 3,993	14	$ 0.29

As mentioned in Section 2.3, this evaluation is a response to the most recent M&E plan developed for PY 2016-2020. Each year, our team reviews program tracking data, identifies the population subject to evaluation for that year and develops sampling plans based on the structure and makeup of the program. Below we examine the growth in the SGIP energy storage population from the passage of the M&E plan until now. The years in the figure do not correspond to when a participant applied to the program, as discussed above. Rather, they represent the evaluation year and the number of projects – and overall capacity – receiving rebates by the end of that evaluation year.

Overall, the population frame has grown substantially since 2016, both in the residential and nonresidential sectors. Residential systems constitute the most significant increase in the percentage of systems receiving upfront payments in 2020 when compared to 2019. Likewise, large nonresidential systems subject to evaluation increased by roughly 34% in rebated capacity, with a 15% increase in project count. The values presented in each of the forthcoming figures represent the percentage increase in population count and capacity from the 2019 evaluation to this current 2020 evaluation.

FIGURE 3-5: CHANGE IN SGIP POPULATION FROM 2016 – 2020 (BY PROJECT COUNT)

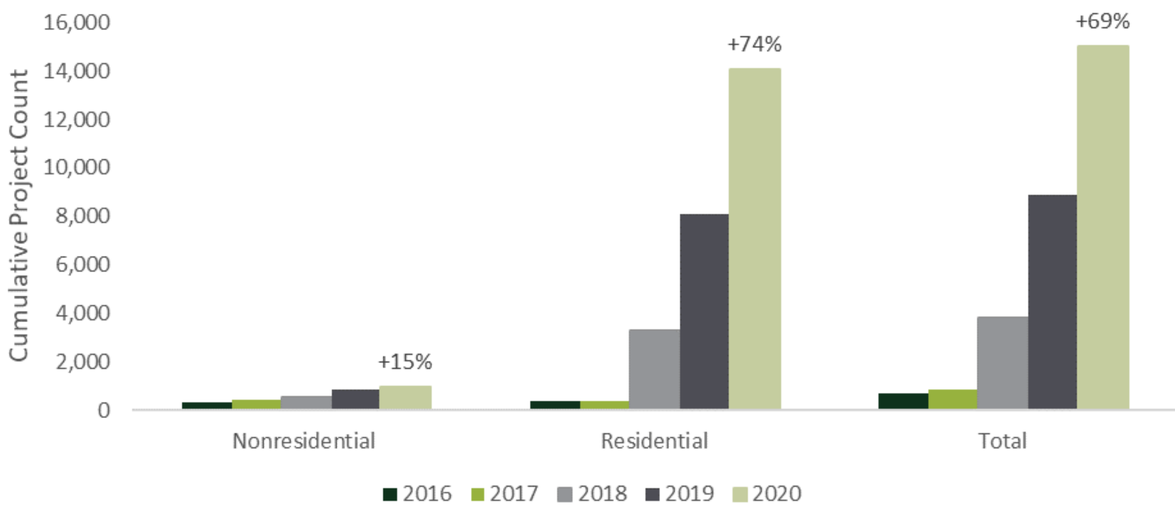


FIGURE 3-6: CHANGE IN SGIP POPULATION FROM 2016 – 2020 (BY REBATED CAPACITY)

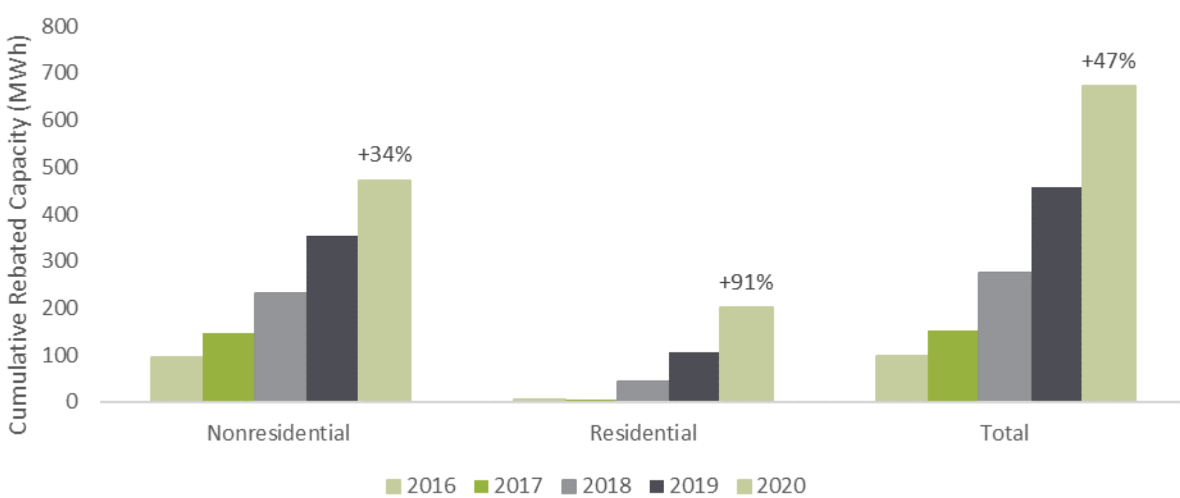


Figure 3-7 shows the breakdown in sector by project count and rebated capacity. While the number of residential systems subject to evaluation in 2020 represents the vast majority by project count (94 percent), the majority of the SGIP storage rebated capacity (70 percent) are installed at nonresidential customer sites. Nonresidential systems are almost always larger and therefore have a greater contribution to total program impacts. They range in size from roughly 10 kWh to over 10,000 kWh, with an average capacity of almost 500 kWh. Residential systems are generally in the 10 kWh to 20 kWh range, with an average capacity of 14 kWh.

FIGURE 3-7: PROJECT COUNT AND REBATED CAPACITY BY CUSTOMER SECTOR

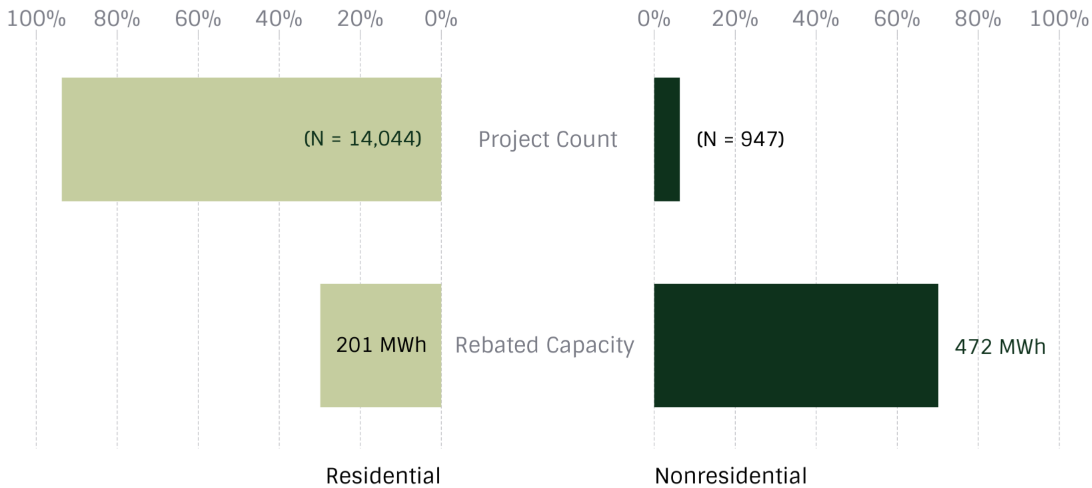
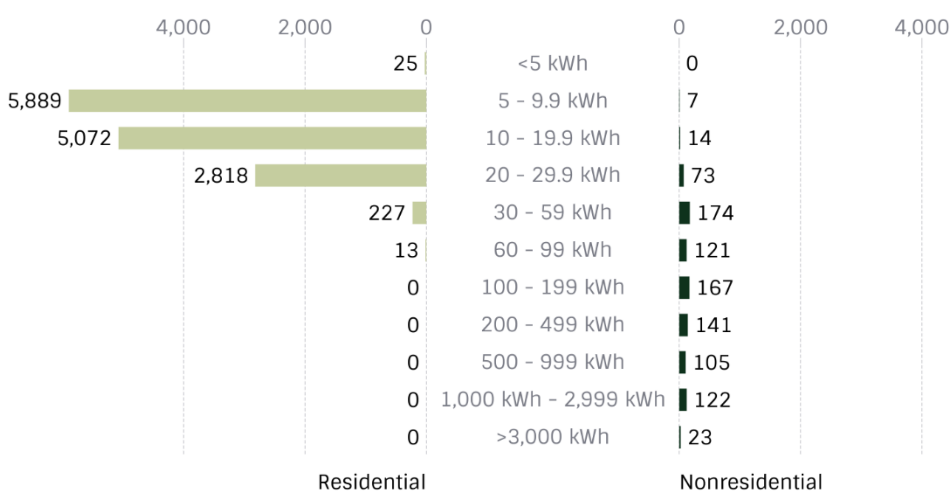


Figure 3-8 provides the distribution of rebated kWh capacity for nonresidential and residential applications. The nonresidential sector represents a much more varied range in capacities than the residential sector. The wide variety of facility types, demand requirements and load shapes in the nonresidential sector lends itself to a much wider range in power (kW) and energy (kWh) capacity.

FIGURE 3-8: REBATED CAPACITY (KWH) BINS BY CUSTOMER SECTOR



Energy storage systems are installed in a variety of nonresidential facility types. Customer segments potentially have different operating schedules throughout the year and varying magnitudes of demand requirements, which can have a significant impact on the behavior of the system. Figure 3-9 summarizes the distribution of nonresidential facility types in the SGIP energy storage population subject to evaluation in 2020, by project count and capacity.[25] Schools and industrial facilities comprise the most nonresidential systems by project count, and along with offices and "Other", by rebated capacity. While there are 107 SGIP storage systems installed in hotels, the average capacity of these systems is smaller than systems installed in other facility types. The average capacity of systems installed in hotels is 55 kWh, compared to 520 kWh in industrial facilities, 350 kWh in schools, and 858 kWh in offices.

FIGURE 3-9: DISTRIBUTION OF BUILDING TYPES WITH ENERGY STORAGE BY PROJECT COUNT AND CAPACITY

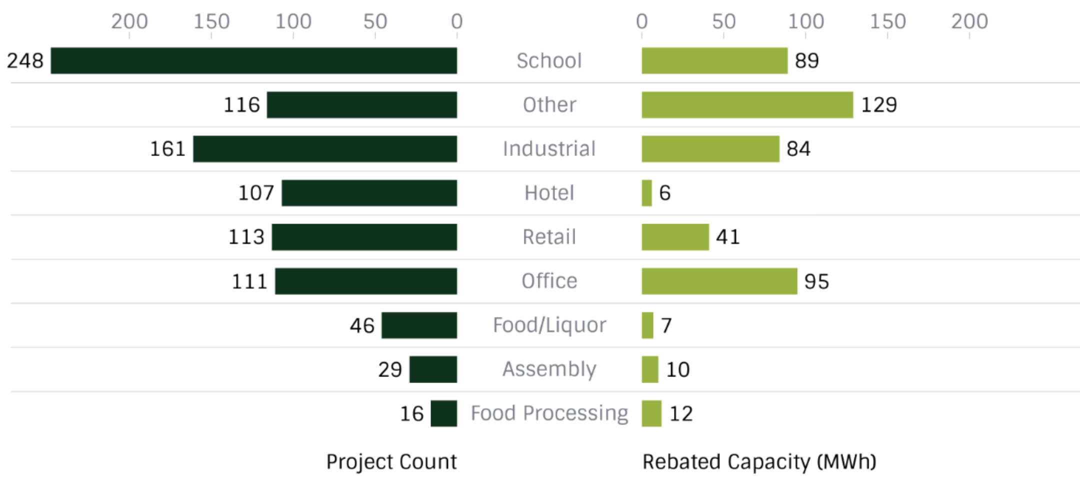


Table 3-2 presents the total number of systems subject to evaluation in 2020 along with the total capacity for each customer sector and program administrator (PA). The 2020 population is comprised of 947 nonresidential and 14,044 residential projects (14,991 total). PG&E has provided the most incentives (5,708), followed by SCE (5,373), CSE (2,885) and SCG (1,025). The distribution of residential and nonresidential projects for each PA by count and capacity are similar, apart from SCE. The nonresidential sector represents a much greater percentage of rebated capacity for SCE.

[25] The Other category consists of facility types with less than 15 represented in the population. This category includes assembly, warehouses, health care facilities, etc.

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TABLE 3-2: 2020 SGIP POPULATION BY PA AND CUSTOMER SECTOR

PA	Customer Segment	Project Count	% Project Count	Rebated Capacity (MWh)	% Rebated Capacity (MWh)
CSE	Nonresidential	210	7%	65	65%
	Residential	2,675	93%	34	35%
	All	**2,885**		**99**	
PG&E	Nonresidential	256	4%	92	53%
	Residential	5,452	96%	81	47%
	All	**5,708**		**173**	
SCE	Nonresidential	437	8%	286	81%
	Residential	4,936	92%	69	19%
	All	**5,373**		**355**	
SCG	Nonresidential	44	4%	29	63%
	Residential	981	96%	17	37%
	All	**1,025**		**46**	
Total	Nonresidential	947	6%	472	70%
	Residential	14,044	94%	201	30%
	All	***14,991***		***673***	

SGIP storage incentives are also available to any California IOU customer. When the PA is a gas-only IOU the electric service may be provided by a municipal utility. Table 3-3 summarizes the number of projects and rebated capacity by PA and electric utility type. PG&E and Southern California Gas Company are the only PAs with energy storage systems installed at non-IOU electric customer locations.[26] Overall, SGIP energy storage systems installed at electric-IOU customer locations represent roughly 95 percent of all installations.

TABLE 3-3: ENERGY STORAGE PROJECT COUNT AND REBATED CAPACITY BY PA AND ELECTRIC UTILITY TYPE

Program Administrator	Number of Projects		Rebated Capacity (kW)	
	Electric IOU	Municipal	Electric IOU	Municipal
Pacific Gas and Electric	5,574	134	171	2
Southern California Edison	5,372	1	355	
Southern California Gas Company	190	835	29	17
Center for Sustainable Energy	2,885		99	
Total	**14,021**	**970**	**655**	**18**

26 Municipal utilities include LADWP, Sacramento Municipal Utility District (SMUD), City of Glendale, and Anaheim Public Utility, among others.

4 SAMPLE CHARACTERIZATION

This section details the sampling plan for the 2020 SGIP energy storage impact evaluation. The sampling strategy was designed to provide statistically significant impacts while maintaining evaluation delivery timelines and project budgets. The following sample design was developed from the 2020 population of SGIP storage projects and is based on several factors: 1) the composition of the 2020 population of SGIP storage projects, 2) availability of underlying data requirements, 3) understanding historical data limitations, 4) results from the 2019 impact evaluation, 5) reporting requirements from D. 19-08-001 and 6) sampling requirements needed to develop population-level metrics with a high level of precision.

The sample design follows an approach consistent with previous evaluations. However, it also accounts for new provisions detailed in D. 19-08-001 regarding greenhouse gas (GHG) emissions reporting. The key provisions set forth in the decision include:

- SGIP PAs are required to provide project developers with a digitally accessible GHG signal of marginal GHG emissions factors (kilograms CO_2/kWh)
- Defines how different operational and compliance pathways influence different project types
  - New projects are those submitting completed applications on or after 4/1/2020
  - Legacy projects are those submitting completed applications 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[27]
- Directs the SGIP storage impact evaluator to provide summary information on the GHG performance of developer fleets as part of annual SGIP storage evaluations
  - Legacy nonresidential and residential developer fleets (Year 1 – 10 of permanency)
  - New nonresidential (Years 6 – 10 of permanency)
  - New residential systems (2026)

This decision was approved in 2019 and was instituted in PY 2020, so the GHG emission reporting is limited to legacy nonresidential and residential developer fleets. New nonresidential and residential projects are ALL within their first year of permanency, so GHG reporting is NOT required for this evaluation. However, the M&E plan calls for an impact evaluation of the program, so new residential and nonresidential systems

[27] Section 11 of the decision defines developer fleet as composed of ten or more projects. For compliance purposes, a developer's (residential or commercial; legacy or new) fleet includes all such projects within their ten-year permanency requirement, whose SGIP agreements list the same developer.

need to be included in the context of population impacts – the evaluator is just not required to include these systems in the fleet level GHG emissions reporting. Verdant has developed a sample design that meets each of these requirements.

Figure 4-1 presents the total number of residential systems subject to evaluation in 2020 (14,044 total systems). It also quantifies how many systems are considered new versus legacy. The 8,071 systems to the far left of the figure are those systems included in the 2019 impact evaluation. These systems, along with 1,061 completed applications in the first three months of 2020, are considered legacy, where our team is required to provide developer fleet level GHG impacts. The 4,912 projects with completed applications on or after 4/1/2020 are defined as new. There is no developer specific GHG reporting requirement for these systems. However, their impacts need to be accounted for in the overall program impact evaluation.

FIGURE 4-1: NEW VERSUS LEGACY RESIDENTIAL SGIP PROJECTS (2020)

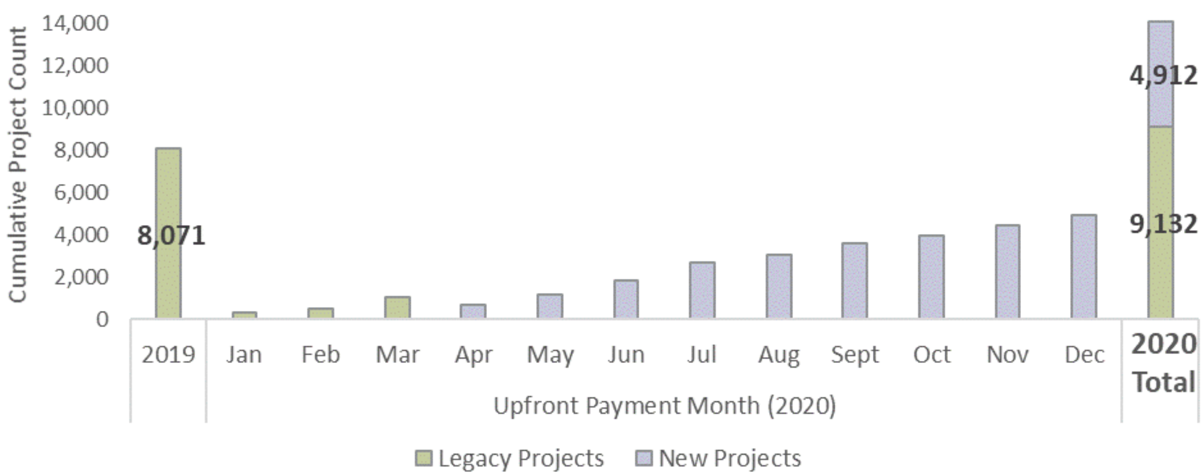
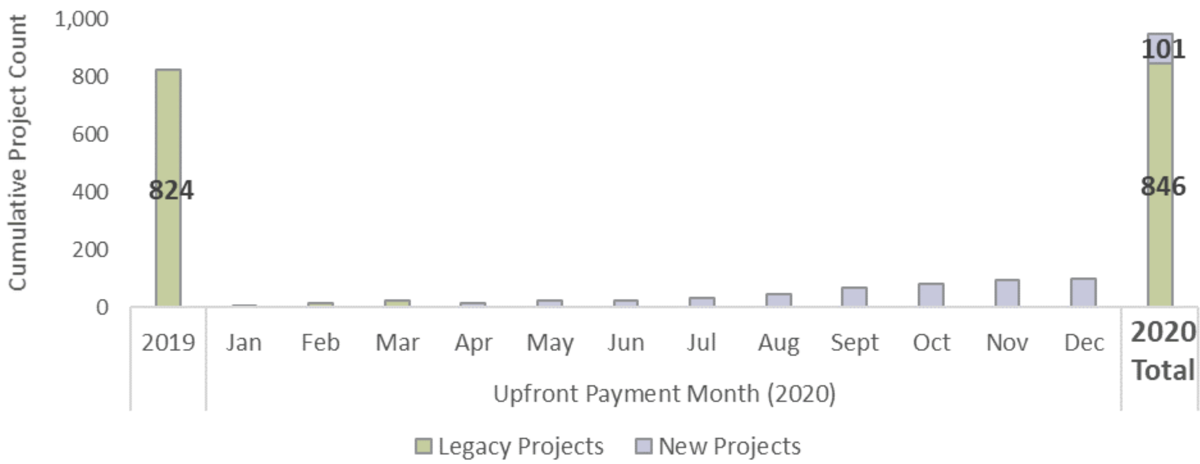


Figure 4-2 presents a similar exhibit, but for nonresidential systems. There are 947 nonresidential systems subject to evaluation for 2020, with 846 of those defined as legacy systems. The sample is designed to develop fleet level GHG impacts for these systems, as well as the combined impacts with the 101 new systems to develop population-level program impacts. The 101 new nonresidential systems are not required for GHG reporting until the sixth year of permanency.

FIGURE 4-2: NEW VERSUS LEGACY NONRESIDENTIAL SGIP PROJECTS (2020)



We have developed a stratified random sampling approach, with an attempted census for some sectors in 2020, given evaluation reporting deadlines, budgetary considerations, and results garnered from the 2019 impact evaluation. To accomplish this, we examined a key design variable – greenhouse gas emissions – from the 2019 impact evaluation. We reviewed developer GHG emissions in 2019 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 2020 to reach an estimate of GHG impacts at the project developer level with a high-level of precision.

Figure 4-3 conveys how the relationship between sample size and coefficients of variation[28] (CV) affect resulting precision estimates at the 90% confidence interval.[29] With a CV of 0.4, the evaluator could achieve a 10% relative precision at the 90% CI with roughly 50 sample points. As the variability in the estimates 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 at the 90% CI.

[28] The coefficient of variation is the standard deviation of a parameter divided by its mean which allows for the comparison of variation across disparate distributions.

[29] 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.

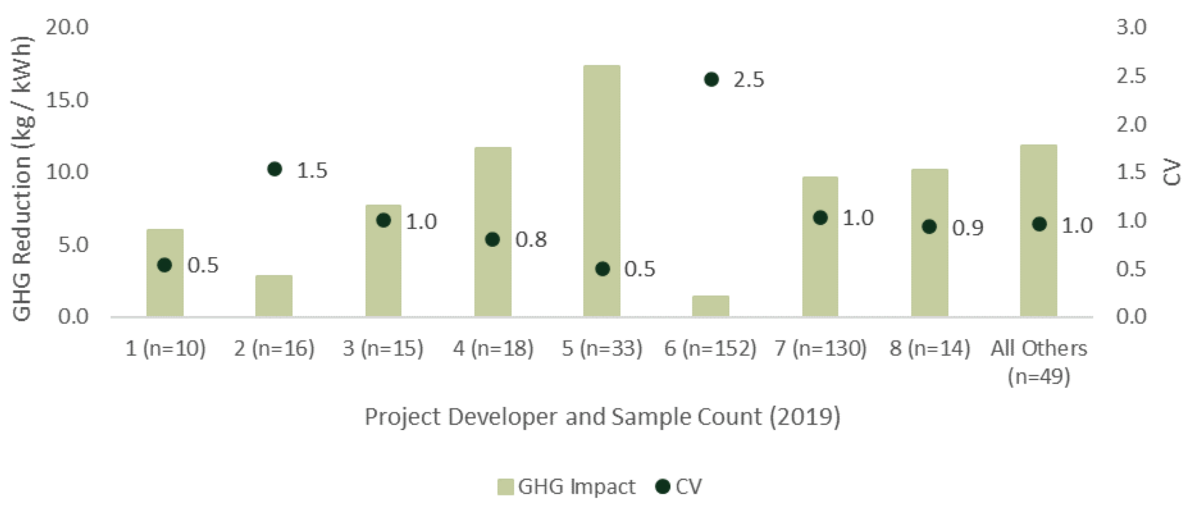
FIGURE 4-3: SAMPLE SIZE REQUIREMENTS AND COEFFICIENT OF VARIATION AT THE 90% CONFIDENCE INTERVAL

		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%

4.1 SAMPLE PLAN FOR RESIDENTIAL SYSTEMS

We analyzed the sample of residential projects from the 2019 impact evaluation and re-developed greenhouse gas impacts for each project developer in our sample. Figure 4-4 presents those findings. The impacts represent a *decrease* in kilograms of GHG emissions per rebated capacity (kWh). The magnitude of GHG emissions reductions is displayed on the left vertical axis and the corresponding CV is presented on the right vertical axis. The horizontal axis presents the eight individual developers where we had at least 10 sample points of data in 2019, and the "All Others" category are all the remaining developers where we had less than 10 sample observations. Project developer names have been anonymized for confidentiality purposes.

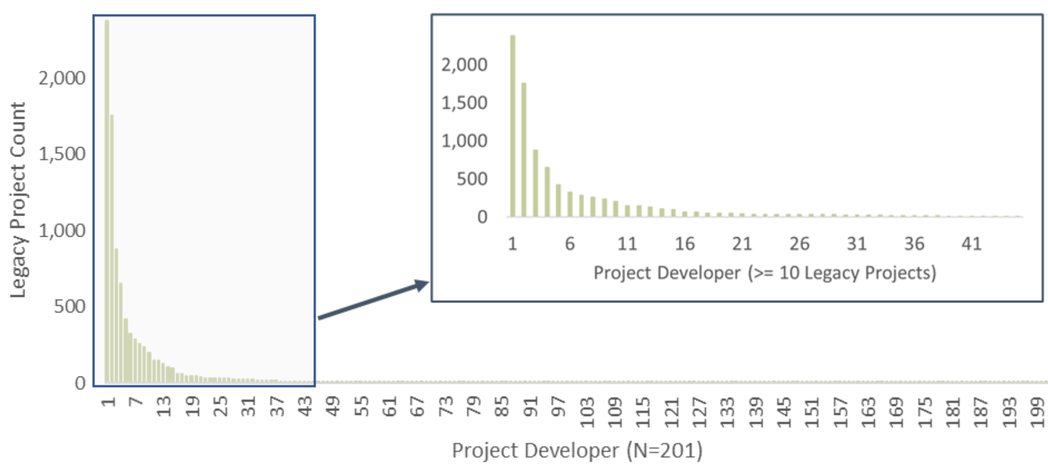
FIGURE 4-4: GREENHOUSE GAS EMISSIONS AND CV BY RESIDENTIAL PROJECT DEVELOPER (2019)



On average, the behavior of each developer's energy storage fleet led to a decrease in emissions in 2019. While there is significant variability in the sample mean estimate for each – an average reduction of 17.1 kg / kWh for Developer 5 and a 1.4 kg / kWh decrease for Developer 6 – relative precision estimates were all within 15% to 67% measured at the 90% confidence interval. 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 all residential developers reduced emissions in 2019. The CV for most developers is around 1.0, which would require almost 300 sample points from each developer to achieve 10% relative precision at the 90% confidence interval (90/10) and roughly 68 sample points for 90/20.[30] One developer has a much higher CV of 2.5. We observed considerable inter-project variations with this developer along with a very small measurement value.[31] A CV of 2.5 would require roughly 2,000 observations to achieve 90/10 or 500 sample observations for 90/20.

Next, we reviewed the 2020 program tracking data subject to evaluation to identify: 1) the unique number of project developers installing SGIP rebated 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 4-5 provides those results. Our analysis shows 201 unique developers installed at least one SGIP *legacy* project, with *legacy* defined as any project completing their application prior to 4/1/2020. Of those 201 unique developers, 45 installed 10 or more systems (the inset bar chart within the figure).

FIGURE 4-5: COUNT OF LEGACY RESIDENTIAL PROJECTS BY PROJECT DEVELOPER (2020)



[30] These estimates carry the assumption of a large population to pull sample from. As the sample size increases relative to the size of a finite population, use of the finite population correction (FPC) factor will increase the precision.

[31] Mathematically, the relative error approaches infinity as the measurement value goes toward zero.

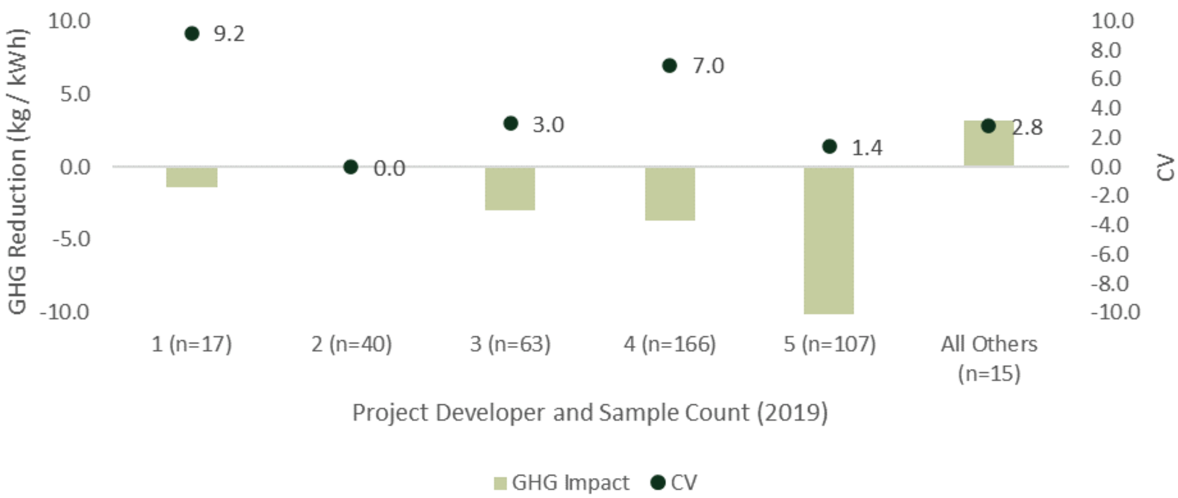
Those 45 unique developers constitute *developer fleets* and, as the program evaluator, Verdant is directed to develop summary GHG emissions data for these fleets as part of this impact evaluation. The other 156 developers, along with any other *new* projects, those completing applications on or after 4/1/2020, do not require developer summaries of GHG performance. However, our team has sampled from these projects to develop population level impact results for the overall program. Our overall proposed sample design was developed to:

- Develop legacy developer fleet GHG performance impacts at 90/20 or better
- Ensure sample sizes reflect the distribution of systems in the population. For example, with a CV of 1.0, our team would only need to sample 68 projects from Developer 2 to create developer GHG impacts at 90/20. However, this developer represents roughly 14% of all residential projects in the program, so we are over-sampling to account for that.
- Develop population-level GHG performance impacts at the overall residential sector level – along with other impact metrics like total avoided utility costs, coincident peak demand, and roundtrip efficiency (RTE) – at 90/10 or better

4.2 SAMPLE PLAN FOR NONRESIDENTIAL PROJECTS

We also analyzed the sample of nonresidential projects from the 2019 impact evaluation and re-developed greenhouse gas impacts for each project developer in our nonresidential sample. Figure 4-4 presents those findings. Negative impacts (-) represent an *increase* in kilograms of GHG emissions per rebated capacity (kWh). The magnitude of GHG emissions is displayed on the left vertical axis and the corresponding CV is presented on the right vertical axis. The horizontal axis presents the six individual developers where we had at least 10 sample points of data in 2019, and the “All Others” category are all the remaining developers where we had less than 10 sample observations. Project developer names have been anonymized for confidentiality purposes.

FIGURE 4-6: GREENHOUSE GAS EMISSIONS AND CV BY NONRESIDENTIAL PROJECT DEVELOPER (2019)

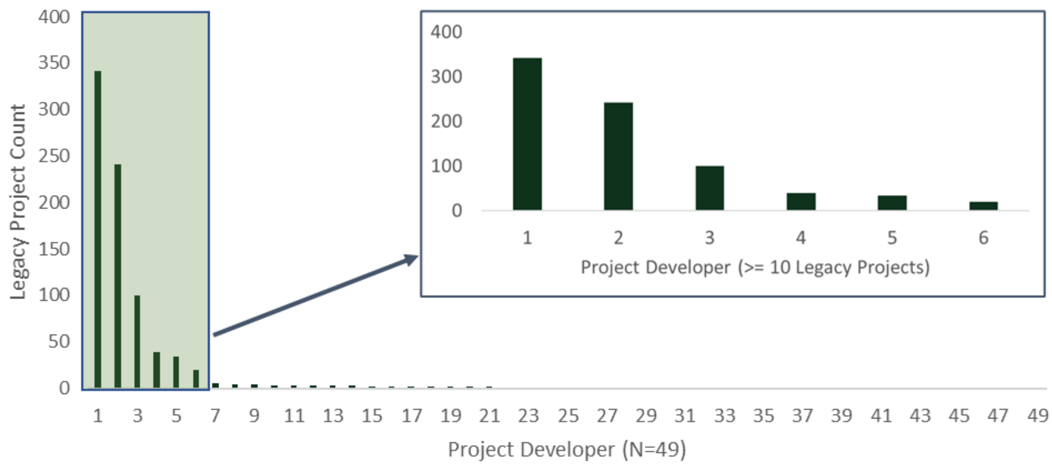


On average, the behavior of each developer's energy storage fleet led to an increase in emissions in 2019, except for Developer 2[32] and "All Others". There is significant variability in the sample mean estimate for each, and relative precision estimates ranged from 22% to 388% measured at the 90% confidence 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 (Figure 3-8), 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 should be much greater – as a percentage of the population – for nonresidential developers. Furthermore, nonresidential projects represent 65% of total MWh capacity of the program, so their behavior within a given year has a significant impact on the overall performance of the program.

Next, we reviewed the 2020 program tracking data subject to evaluation to identify; 1) the unique number of project developers installing SGIP rebated 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 4-7 provides those results. Our analysis shows 49 unique developers installed at least one SGIP *legacy* project, with *legacy* defined as any project completing their application prior to 4/1/2020. Of those 49 unique developers, six installed 10 or more systems (the inset bar chart within the figure).

32 This developer filed for bankruptcy and systems have been decommissioned, removed or have remained off-line.

FIGURE 4-7: COUNT OF LEGACY NONRESIDENTIAL PROJECTS BY PROJECT DEVELOPER (2020)



Those six unique developers constitute *developer fleets* and, as the program evaluator, Verdant is directed to submit summary GHG emissions data for these fleets as part of this impact evaluation. The other 56 developers, along with any other *new* projects, those completing applications on or after 4/1/2020, do not require developer summaries of GHG performance. However, our team drew sample from these projects to develop population level impact results for the overall program. Our overall proposed sample design was developed to:

- Develop legacy developer fleet GHG performance impacts at 90/20 or better. Given the high CV estimates, we attempt a census for all but one developer. The CV for this developer was 1.4, so we expect 90/20 with 150 sample points
- Develop population-level GHG performance 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

4.3 ACHIEVED SAMPLE COUNTS AND CAPACITIES

This section summarizes the sampled projects analyzed as part of this evaluation. The achieved sample are presented for each of the four PAs by customer sector as well as at the statewide level. The total number of residential projects sampled range from 12% to 29% of all projects, and 50% to 95% for the nonresidential sector. The percentage of capacity sampled is much greater in the nonresidential sector, ranging from 14% to almost 100%. Overall, Verdant evaluated roughly 20% of all projects and 71% of total storage program capacity in 2020.

TABLE 4-1: 2020 SGIP EVALUATED SAMPLE AND POPULATION BY PA AND CUSTOMER SECTOR

PA	Customer Segment	Legacy	Sample Count	Population Count	% Project Count Sampled	Sample Capacity (MWh)	Population Capacity (MWh)	% Sampled Capacity (MWh)
CSE	Nonresidential	Yes	118	202	58%	48	55	87%
		No	4	8	50%	1	10	14%
	Residential	Yes	286	1,878	15%	4	23	20%
		No	104	797	13%	2	12	17%
	All		**512**	**2,885**	**18%**	**55**	**99**	**56%**
PG&E	Nonresidential	Yes	127	225	56%	62	71	87%
		No	26	31	84%	19	21	94%
	Residential	Yes	621	3,553	17%	11	49	22%
		No	247	1,899	13%	5	32	15%
	All		**1,021**	**5,708**	**18%**	**97**	**173**	**56%**
SCE	Nonresidential	Yes	299	382	78%	221	227	97%
		No	48	55	87%	56	59	94%
	Residential	Yes	593	3,211	18%	10	42	23%
		No	210	1,725	12%	4	27	14%
	All		**1,150**	**5,373**	**21%**	**290**	**355**	**82%**
SCG	Nonresidential	Yes	35	37	95%	23	23	100%
		No	6	7	86%	6	6	99%
	Residential	Yes	141	491	29%	3	8	32%
		No	70	490	14%	1	9	16%
	All		**252**	**1,025**	**25%**	**33**	**37**	**89%**
Total	Nonresidential	Yes	***579***	***846***	***68%***	***353***	***376***	***94%***
		No	***84***	***101***	***83%***	***82***	***96***	***86%***
	Residential	Yes	***1,642***	***9,133***	***18%***	***27***	***121***	***23%***
		No	***631***	***4,911***	***13%***	***12***	***80***	***15%***
	All		***2,936***	***14,991***	***20%***	***475***	***673***	***71%***

4.4 SGIP POPULATION BEYOND 2020

The above sections detail the characterization of the SGIP energy storage population subject to evaluation in 2020 and provides a summary of how changes to the composition of that population from previous years dictated the evaluation approach. Residential systems constitute the most significant increase in the percentage of systems receiving upfront payments in 2020 when compared to 2019 and prior. Large nonresidential systems subject to evaluation in 2020 have increased relative to 2019 as well. Far fewer nonresidential projects were applying to the program in 2020, but applications submitted in previous years received incentives in 2020 after working their way through the application process.

While the remainder of this report presents the results associated with systems subject to evaluation in 2020, here we provide a snapshot of how the composition of the population is changing in 2021. Many of the conclusions and recommendations detailed in the Executive Summary are based on results garnered from this impact evaluation. Some, however, are forward looking and are predicated on an understanding of how the SGIP evolves from one year to the next.

Figure 4-8 and Figure 4-9 provide a snapshot of how the SGIP has evolved from 2019 to 2020 and what we expect the population to look like for the forthcoming 2021 evaluation year. The SGIP project list for 2021 was downloaded on October 20th, so the population will likely increase as more systems receive incentive payments through the latter months of the year. However, the trend is evident. The 2021 population will include many more residential systems, with modest growth from the nonresidential sector. The values presented in each of the forthcoming figures represent the percentage increase in population count and capacity from the 2020 population evaluation to the current 2021 population status (as of 10/20/2021).

FIGURE 4-8: CHANGE IN SGIP STORAGE POPULATION 2019 – 2021 (BY CAPACITY)

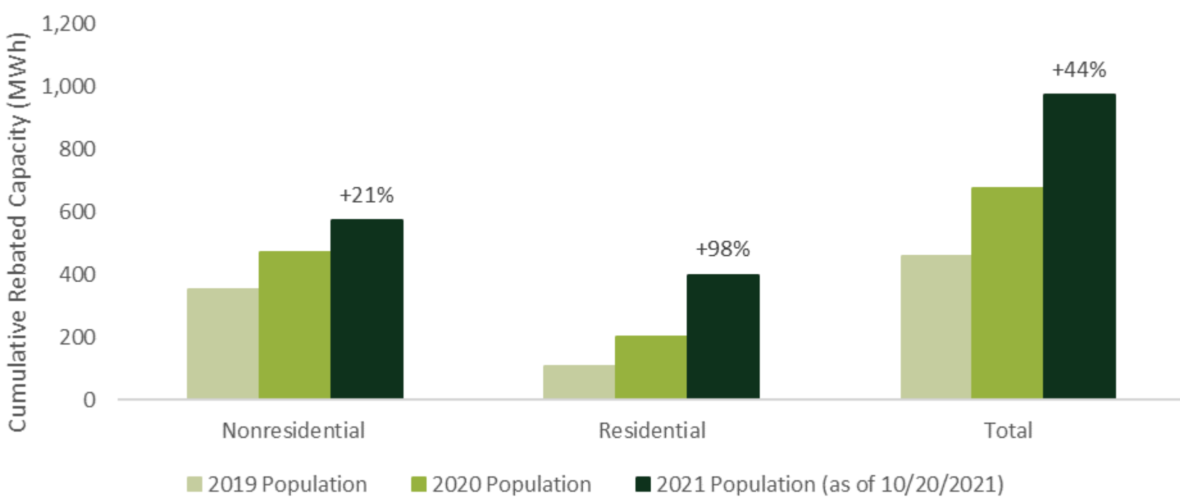
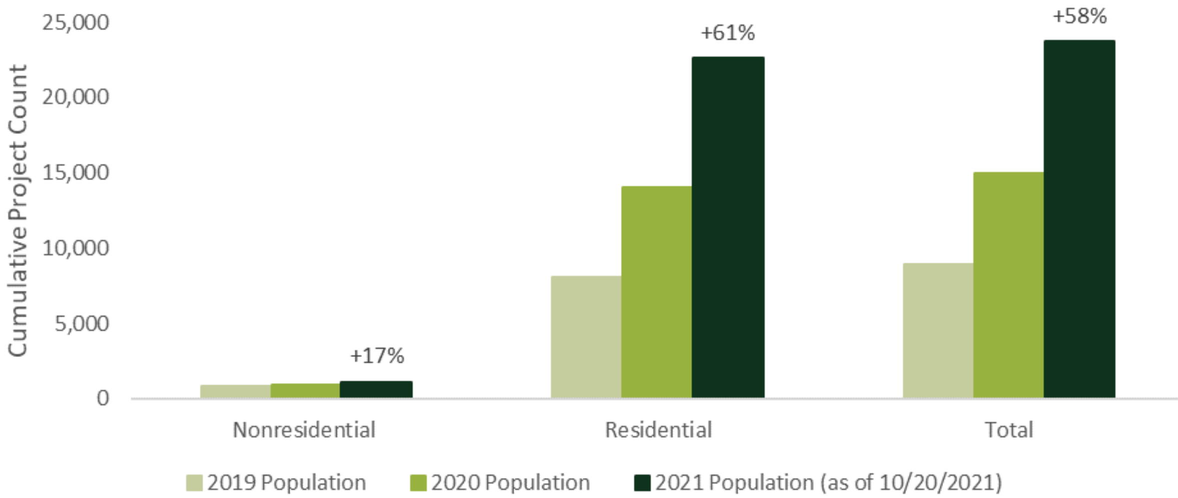


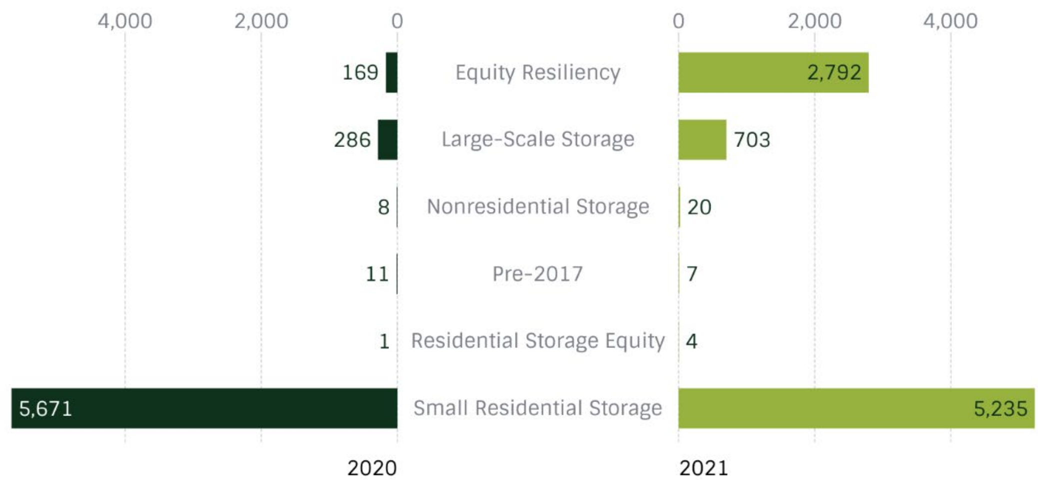
FIGURE 4-9: CHANGE IN SGIP STORAGE POPULATION 2019 – 2021 (BY PROJECT COUNT)



Significant changes to the SGIP focus, rules, and requirements took place in 2020. The 2021 evaluation year will further usher in some material changes to the program that will continue to impact how we evaluate it moving forward. These include the continued implementation of the newly established equity resiliency budget, in addition to continued increases in small residential program participation. During 2020, the SGIP first saw the introduction of new greenhouse gas (GHG) reporting rules for storage projects and the requirement for residential participants to switch to time-of-use (TOU) rates. These types of changes were implemented throughout 2020, so a full year of impacts from these rules and requirements will be observed in 2021.

Below we present some of the changes from 2020 through 2021 by budget category. Small residential storage incentives represent the most significant share, at a magnitude just less than what was observed in 2020. Large-scale storage projects have increased more than two-fold, increasing to 703 projects in 2021. The most significant growth, however, is with customers accessing incentives through the equity resiliency budget. There were 169 projects subject to evaluation in 2020 from this category. As of 10/20/2021, incentives have been issued to roughly 2,800 equity resiliency projects, and with a longer and more extensive fire season in 2021, it will be critical to further test the capability of these systems to provide resiliency and support to customers throughout public safety power shut-off (PSPS) events and other outages.

FIGURE 4-10: CHANGE IN SGIP STORAGE POPULATION 2020 (BY BUDGET CATEGORY)



5 OBSERVED SGIP ENERGY STORAGE IMPACTS

The primary objective of this study is to evaluate the performance of energy storage systems rebated through the Self-Generation Incentive Program (SGIP) and operating during calendar year 2020. This section examines the performance of these systems and presents the observed impacts of SGIP energy storage. These impacts include:

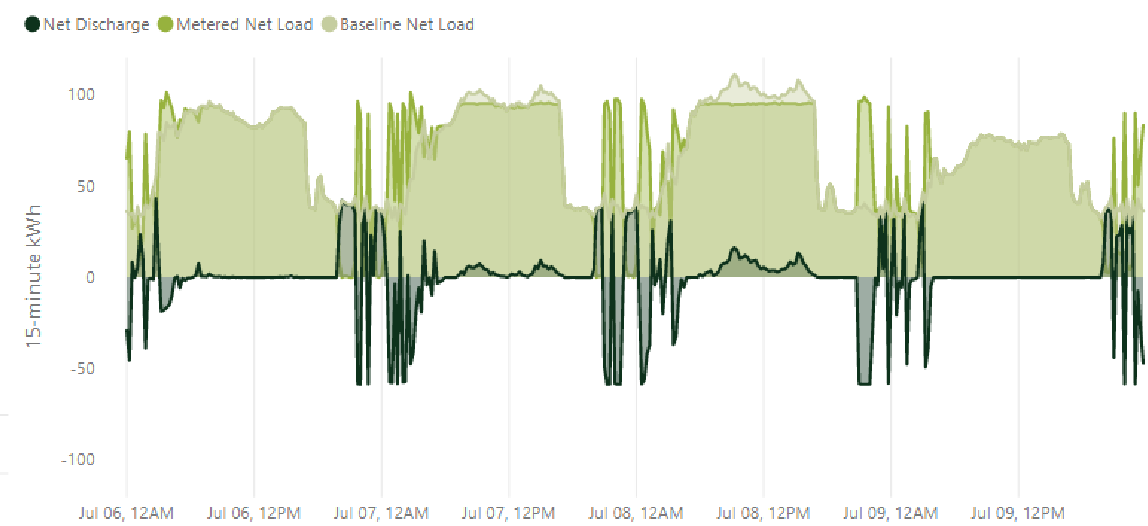
- **Observed Performance Impacts – Section 5.1**
  - Calculate roundtrip efficiencies (RTEs), capacity factors (CF), number of discharge cycles
  - Compare system performance in 2020 to performance in 2019
- **Observed Customer Impacts – Section 5.2**
  - Analyze and/or quantify charge/discharge behavior in relation to customer non-coincident peak demand, time-of-use (TOU) schedules and monthly bill savings
- **Observed CAISO and IOU System Impacts – Section 5.3**
  - Analyze and quantify charge/discharge behavior in relation to CAISO system load and utility coincident peak demand
- **Observed Environmental Impacts – Section 5.4**
  - Analyze and quantify charge/discharge behavior in relation to marginal greenhouse gas (GHG) emissions
- **Observed Utility Marginal Cost Impacts – Section 5.5**
  - Analyze charge/discharge behavior in relation to utility marginal costs as quantified in the CPUC 2021 Avoided Cost Calculator
- **Observed System Behavior During Public Safety Power Shutoff (PSPS) Events – Section 5.6**
  - Analyze and quantity how storage systems are being utilized for customers affected by PSPS events during high wildfire risk periods
- **Energy Storage Program Level Impacts – Section 5.7**
  - Combine project-specific sample data from the objectives above to *quantify the magnitude* of total population level impacts for SGIP energy storage systems operating throughout 2020

Baselines and Impact Methodology

Some of these impacts and metrics discussed in this report are developed to better understand the efficiency of the system or how well utilized the system was throughout the year. These metrics, such as the RTE or CF, can be calculated directly from storage charge and discharge data. Other impacts, such as customer bill impacts, involve making assumptions about a customer's consumption prior to the installation of the energy storage system. Quantifying these impacts requires developing counterfactuals – how would a customer service load in a baseline where no storage exists – and comparing that baseline to what was observed. The latter value is metered and can be directly measured. The former value is a calculated one – taking the metered net load with storage and subtracting out the influence of storage. In other words, Verdant assumes no behavior change resulting from the customer's installation of battery storage.

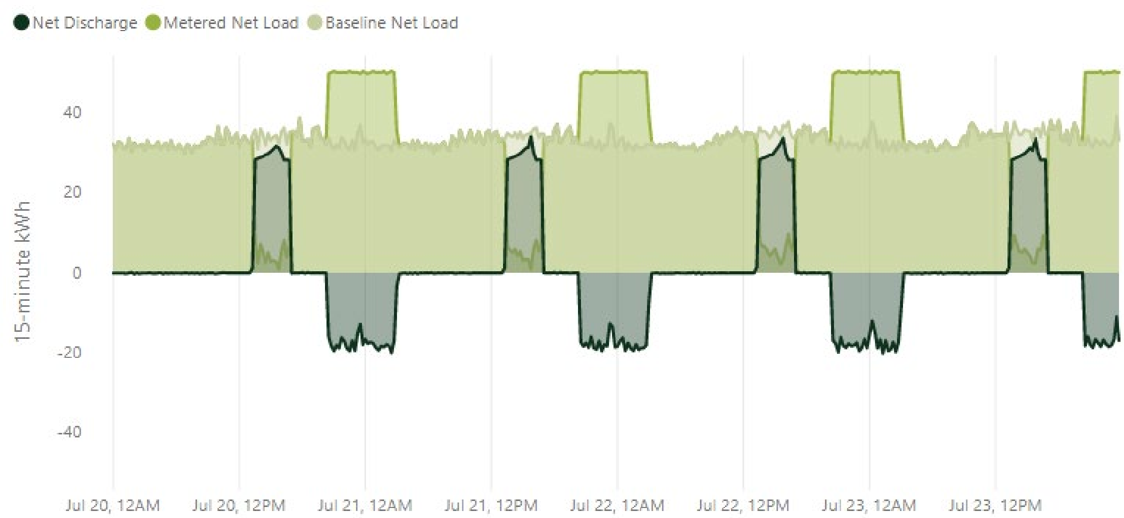
An example of how Verdant develops billing impacts based on this baseline methodology is presented below in Figure 5-1. A four-day load shape is provided for a commercial customer. Energy storage discharge (+) and charge (-) are plotted in dark green, metered net load is presented in lighter green and the baseline calculated load – the metered load minus the influence of storage – is plotted in the lightest green. During overnight hours, the battery is cycling – increasing metered load when charging and reducing load when discharging. During the second and third day, however, the storage system is discharging throughout the daytime. This discharge occurs when facility load is peaking. The battery is programmed to discharge to maintain load below a certain threshold. When Verdant develops bill impacts, we assume the baseline load represents the lightest green and the measure case is the metered net load with the influence of storage. The delta between those two values represents the difference in peak demand or energy usage at the facility. If monthly peak demand in the measure case is less than the baseline peak demand, then a customer will realize monthly demand charge reductions on their bill.

FIGURE 5-1: EXAMPLE 1 NONRESIDENTIAL FACILITY WITH METERED AND BASELINE NET LOAD



A second example describing GHG impacts is provided in Figure 5-2. Based on our methodology, this customer has a consistent load of roughly 30 kWh throughout all four days in the baseline. Installation of the energy storage system changes the shape and magnitude of demand. On all four days, the battery consistently discharges throughout the same afternoon/early evening hours. This discharge brings net load close to zero during those time periods. Overnight, presumably after on-peak time-of-use periods, the battery charges from the grid, leading to an increase in load. Much like bill impacts, greenhouse gas impacts involve the same baseline methodology. If a customer is discharging their battery, they are reducing the need to service load from the grid. When a customer is charging the battery, they are increasing their load relative to a baseline of no storage. If the emissions *avoided* during storage discharge are greater than the emission increases during storage charging, then the customer can realize GHG reductions.

FIGURE 5-2: EXAMPLE 2 NONRESIDENTIAL FACILITY WITH METERED AND BASELINE NET LOAD



Decommissioned and Off-line Projects

The forthcoming analyses include only sampled projects where the storage system was installed and operable throughout 2020. Our team has identified, throughout the past few evaluation cycles, systems that are offline or have been decommissioned. Most of these systems applied to the SGIP throughout earlier program years (2009 – 2014) and in the case of one developer, all their systems have been removed or remain offline after bankruptcy filing. Verdant has identified a total of 73 nonresidential systems that are offline or were decommissioned prior to or during 2020. These systems are not included in the forthcoming analyses; however, their non-performance is captured when developing program population impacts. When developing the research plan and sample design for this study, Verdant identified these projects so they were not randomly sampled. In effect, we conducted a census on these projects, so they will each represent themselves when rolling up sample impacts to the population.

5.1 OBSERVED PERFORMANCE METRICS

Verdant reviewed three performance metrics within the SGIP – capacity factor (CF), roundtrip efficiency (RTE) and annual energy storage cycling – to better understand the efficiency and utilization of the systems throughout 2020. 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 2019 and 2020.

5.1.1 Capacity Factor

Capacity factor is a measure of system utilization. It is defined as the sum of the storage discharge (in kWh) divided by the maximum possible discharge throughout a given period. This is based on the SGIP rebated capacity of the system (in kW) and the total hours of operation. When defining capacity factor, the SGIP handbook[33] assumes 5,200 maximum hours of operation in a year rather than the full 8,760 hours (60 percent).[34] For purposes of SGIP evaluation, the energy storage capacity factor is calculated as:

$$Capacity\ Factor = \frac{\sum kWh\ Discharge\ (kWh)}{Hours\ of\ Data\ Available \times\ Rebated\ Capacity\ (kW) \times\ 60\%}$$

The capacity factors for the sample of nonresidential storage systems are presented below in Figure 5-3. To better understand the range in system utilization throughout the year, boxplots are provided and binned by the year in which a customer received their upfront incentive payment. The horizontal line within each boxplot represents the median value. Sample sizes are also presented. Capacity factors range from as low as 0% (indicating non-performance) to as high as 25%. The average CF ranges from 2% for projects receiving incentive in 2014 to as high as 7% for project receiving incentives in 2019. A trend in greater utilization by systems incented more recently is present, with the exemption of projects rebated in 2020.

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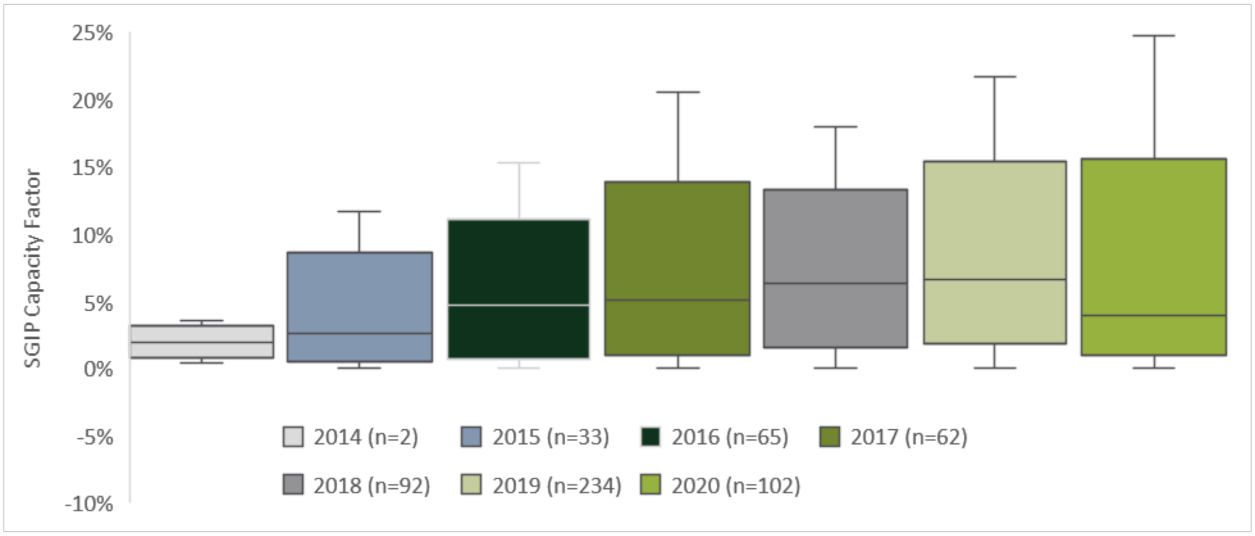
33 2016 Self-Generation Incentive Program Handbook Version 1. Pg. 37. https://www.selfgenca.com/documents/handbook

34 The SGIP Handbook requires performance-based incentive (PBI) projects that applied prior to 2017 to achieve a capacity factor of at least 10 percent per the above formula to receive full payment. Non-PBI systems are not required to meet that 10 percent CF to capture payment.

FIGURE 5-3: BOXPLOT OF CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



The capacity factors for the sample of residential storage systems are presented in Figure 5-4. The average CF are all within 6% to 7% with a similar minimum and maximum range to that of nonresidential systems (0% to 21%). The median value for the first two upfront payment years is 6%, and 5% for 2020 projects.

FIGURE 5-4: BOXPLOT OF CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

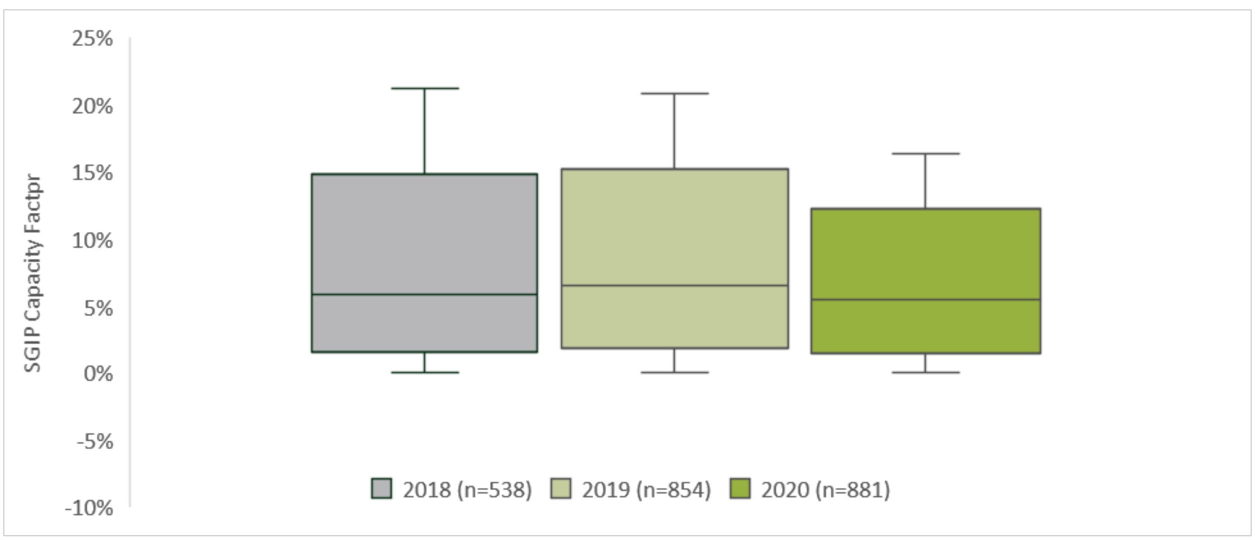
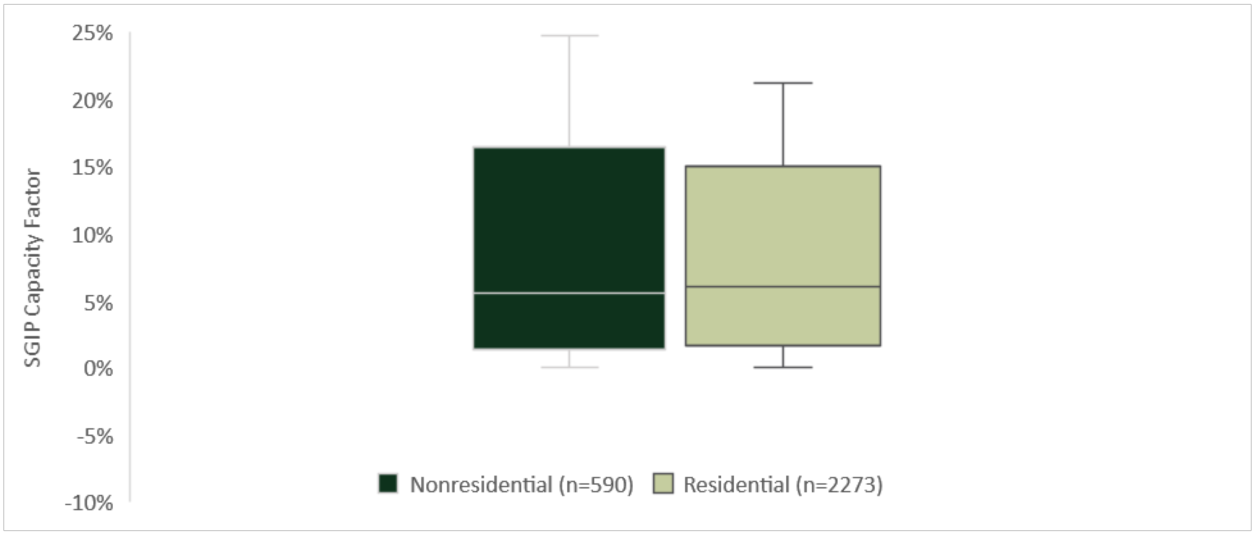


Figure 5-5 presents the overall capacity factor for each host customer sector. The average CF for both sectors was 6% in 2020, with a median value of 6%. The range in performance across both sectors is quite similar as well.

FIGURE 5-5: BOXPLOT OF CAPACITY FACTOR BY CUSTOMER SECTOR



5.1.2 Roundtrip Efficiency

Another key performance metric is roundtrip efficiency (RTE), which is an eligibility requirement for the SGIP.[35] The RTE is defined as the total kWh discharge of the system divided by the total kWh charge. For SGIP evaluation purposes, this metric was calculated for each system over the whole period for which dispatch data were available and deemed verifiable.

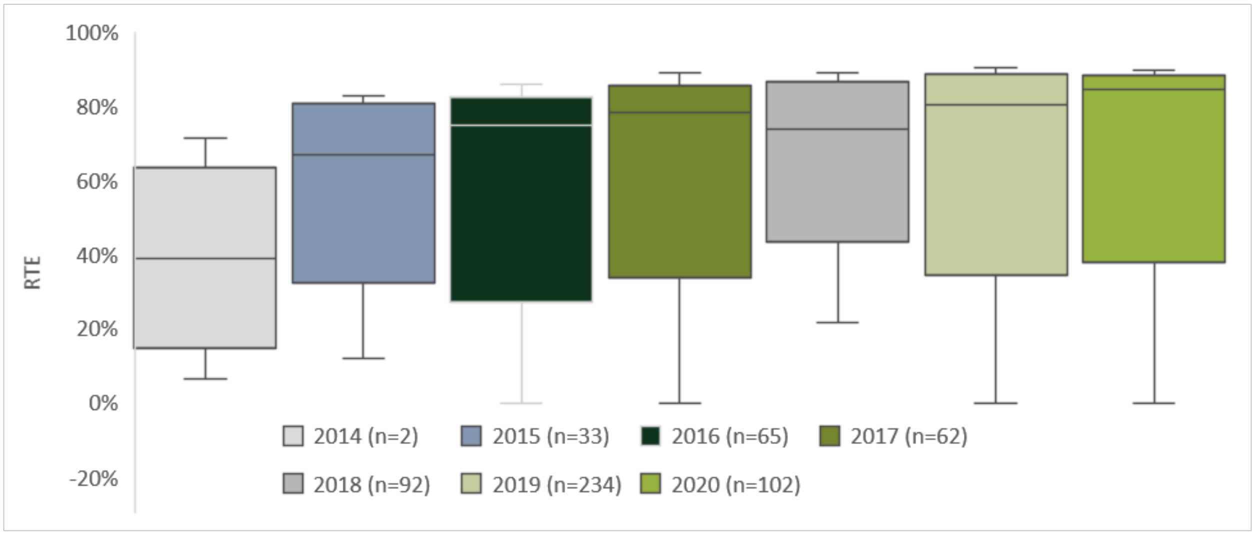
$$Roundtrip\ Efficiency = \frac{\sum kWh\ Discharge\ (kWh)}{\sum kWh\ Charge\ (kWh)}$$

Figure 5-6 presents the distribution of RTE for nonresidential systems by upfront payment year. We observe a trend in increased efficiency for systems rebated more recently, along with a tighter range in sample values. For the 33 projects incented in 2015, the total efficiency was 75%. These systems were

35 Energy storage systems must maintain a round trip efficiency equal to or greater than 69.6 percent in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5 percent, assuming a 1 percent annual degradation rate.

entering their fifth year of operations in 2020. Projects incented and operating in 2020 exhibit a total RTE of 83%.

FIGURE 5-6: BOXPLOT OF RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Residential systems exhibit a far less range in RTE than the nonresidential sector and a higher overall efficiency. Roundtrip efficiencies range from as low as 0% to as high as 91%. The RTE for systems receiving incentives in 2018 was 86%, with a median of 78%. Performance for 2019 and 2020 incented projects is almost identical – with an RTE of 86% respectively, and a median value of 86%. Sample sizes across all three upfront payment years are robust.

FIGURE 5-7: BOXPLOT OF RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

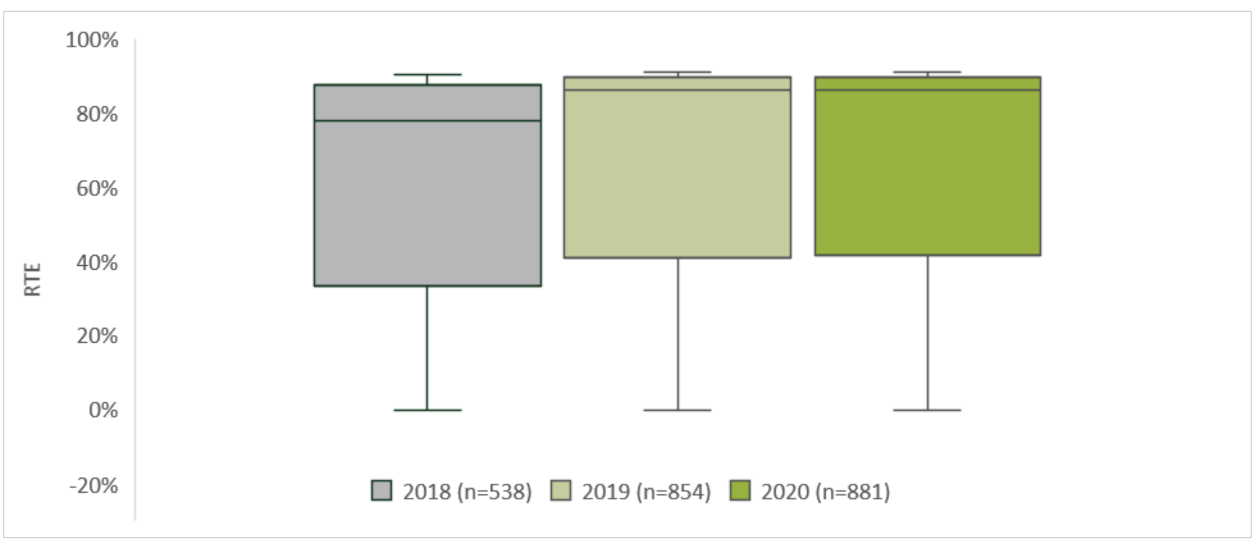


Figure 5-8 presents the overall RTE for each host customer sector. The residential sector exhibits higher overall efficiencies (86%) along with a much tighter range in individual values than the nonresidential sector (81%). The efficiency of the energy storage systems considers a variety of factors, including manufacturer single-cycle RTE specifications, system utilization, magnitude of parasitic loads in relation to utilization, and system degradation over time.

FIGURE 5-8: BOXPLOT OF ANNUAL RTE BY CUSTOMER SECTOR

5.1.3 Discharge Cycles

Finally, this evaluation examines another performance metric, “number of discharges (or cycles)”, which is a measure of system utilization like the CF. This metric 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.[36]

$$Discharge\ Frequency = \frac{\sum kWh\ Discharge\ (kWh)}{Rebated\ Capacity\ (kWh)}$$

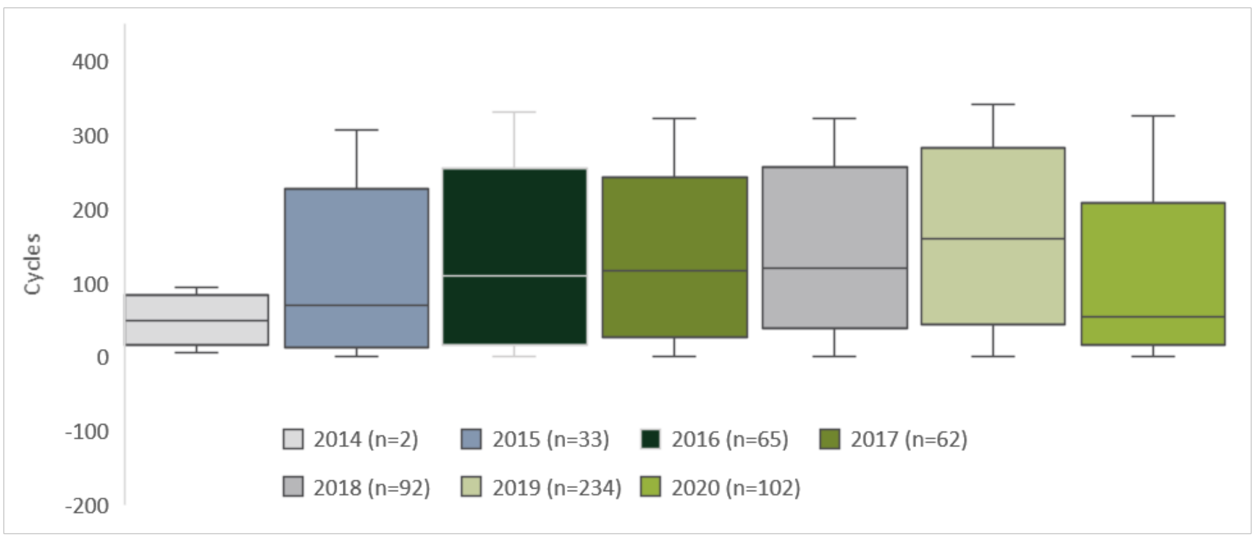
Figure 5-9 presents the number of discharge cycles performed by nonresidential storage systems during 2020. As discharge frequency is a function of utilization like the CF, the range and magnitudes are like

[36] The 2019 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.

those of the CF. There is a general increase in the average number of cycles for systems incented in 2015 (122 discharge cycles) to an average of 166 cycles for systems incented in 2019. To make sense of this metric, if a 50-kWh system discharged 50 percent of capacity once a day, every day throughout the year, this would represent roughly 183 cycles ((50 kWh x 0.5 x 365) / 50 kWh).

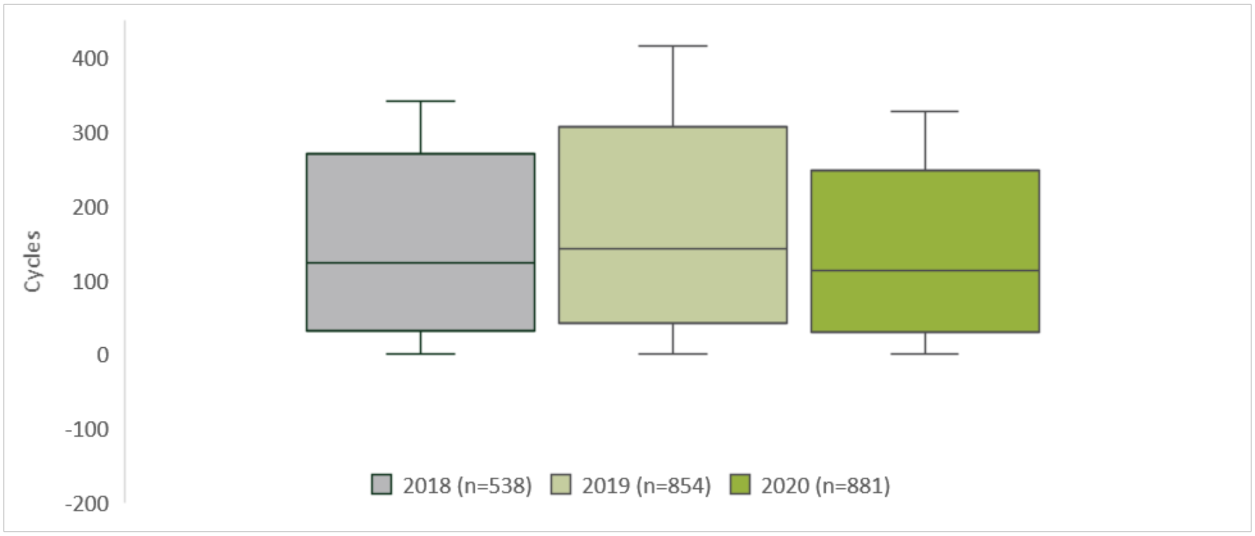
We also observe a noticeable decline in utilization for systems incented throughout 2020. Capacity factors and RTEs measure the utilization and efficiency, respectively, of a system throughout operational periods. With similar utilization, a storage system can exhibit an 80% RTE during one month of activity or throughout a full year of operation. Cycling requires utilization, but also time. Customers receiving upfront payments in October of 2020 do not have the same opportunity to cycle their storage systems as often as a customer being incented in January of 2020. On average, across incentive payment year, nonresidential projects cycled 126 times. The partial year impacts developed for systems incented in 2020, lends itself to fewer cycling opportunities and an average of 84 discharge cycles.

FIGURE 5-9: BOXPLOT OF ANNUAL CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



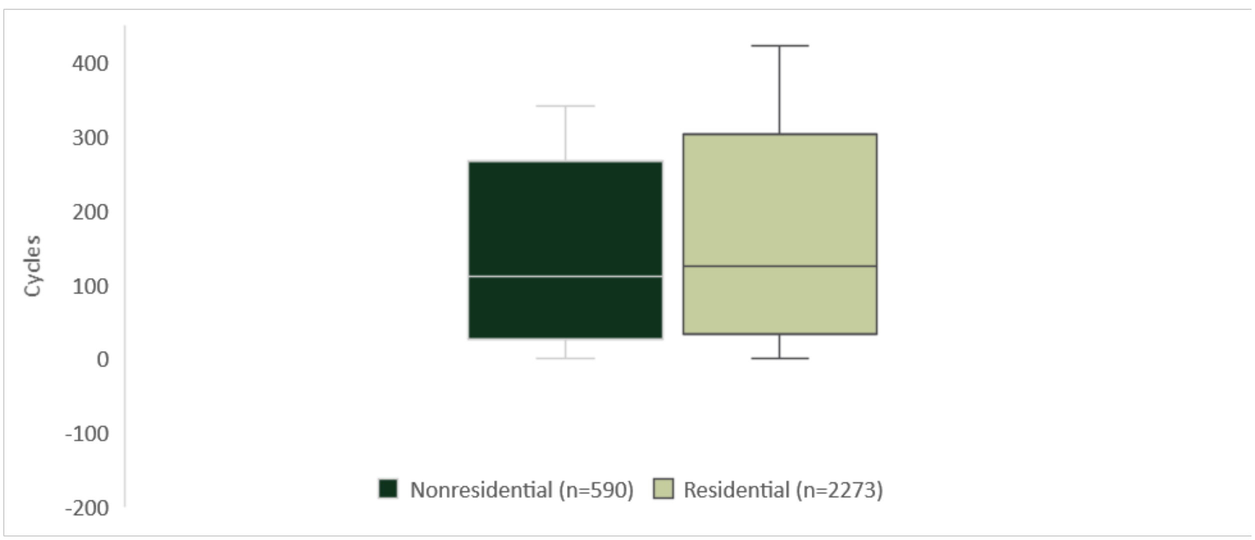
A similar trend is evident in the residential sector. Figure 5-10 presents those results. The average discharge cycles in the residential sector drops from a high of 143 cycles for systems rebated in 2018 and operating in 2020, to 118 discharge cycles for systems incented in 2020. These values are distributed throughout all three upfront payment years, with a maximum of 423 cycles, a minimum of zero and a median value close to the mean for all three groups of systems.

FIGURE 5-10: BOXPLOT OF ANNUAL CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



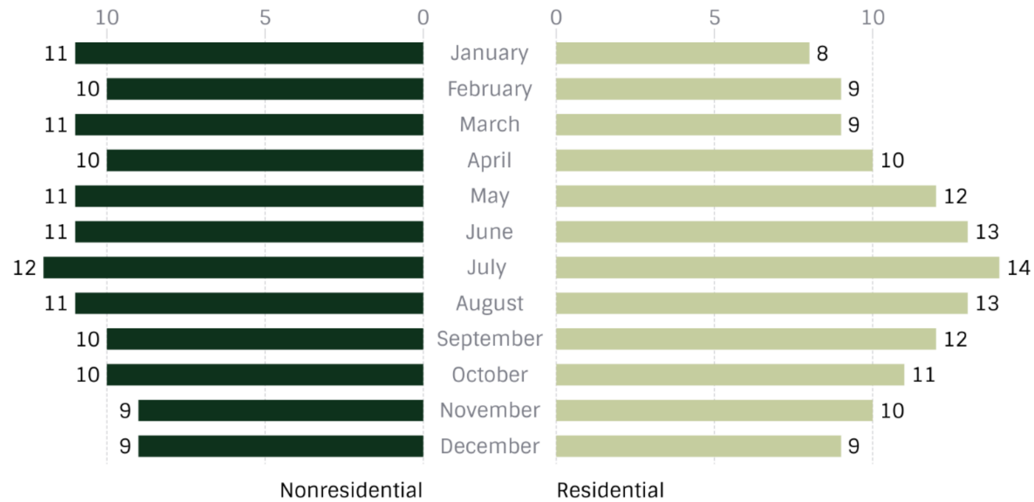
Finally, the overall distribution of annual discharge cycles is provided below in Figure 5-11 for both host customer sectors. Both sectors average roughly 130 discharge cycles in 2020, with a median value of 112 in the nonresidential sector and a median value of 125 in the residential sector.

FIGURE 5-11: BOXPLOT OF ANNUAL CYCLES BY CUSTOMER SECTOR



We also examined the distribution of discharge cycles for each month throughout the year. We observe noticeable increases in utilization of residential storage systems throughout summer months (Figure 5-12). Customer bill impacts ($/kWh and $/kW) and marginal emissions (kg CO_2/kWh) are greatest throughout summer months, so there are far more energy arbitrage and GHG reduction opportunities throughout these time periods. Home consumption generally increases as well throughout summer months when AC load ramps up in response to warmer weather.

FIGURE 5-12: MONTHLY DISCHARGE CYCLES BY CUSTOMER SECTOR



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 consuming. 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 5-13 and Figure 5-14.

Here we map the total number of discharge cycles for each project against the efficiency or RTE of the system. Also included are the upfront payment year and the relative size (in kWh capacity) of the energy storage system, designated by the diameter of each point. We observe a general increase in RTE (vertical axis) as a system is being utilized more often (horizontal axis). The darker green circles represent systems rebated in 2020 and they generally cluster in the top left portion of the figure. These are systems with partial year operations, so their utilization is limited by time. However, their RTEs are high because they are operating efficiently throughout these limited operational time periods.

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These figures also highlight the scale in sizing of nonresidential systems compared to residential ones. As presented in Figure 3-8, the nonresidential sector exhibits a much greater range in storage system capacity than residential systems. Nonresidential systems are installed in a variety of facility types with differing load shapes and demand requirements which lends itself to the significant range in capacity.

FIGURE 5-13: RTE VERSUS DISCHARGE CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE

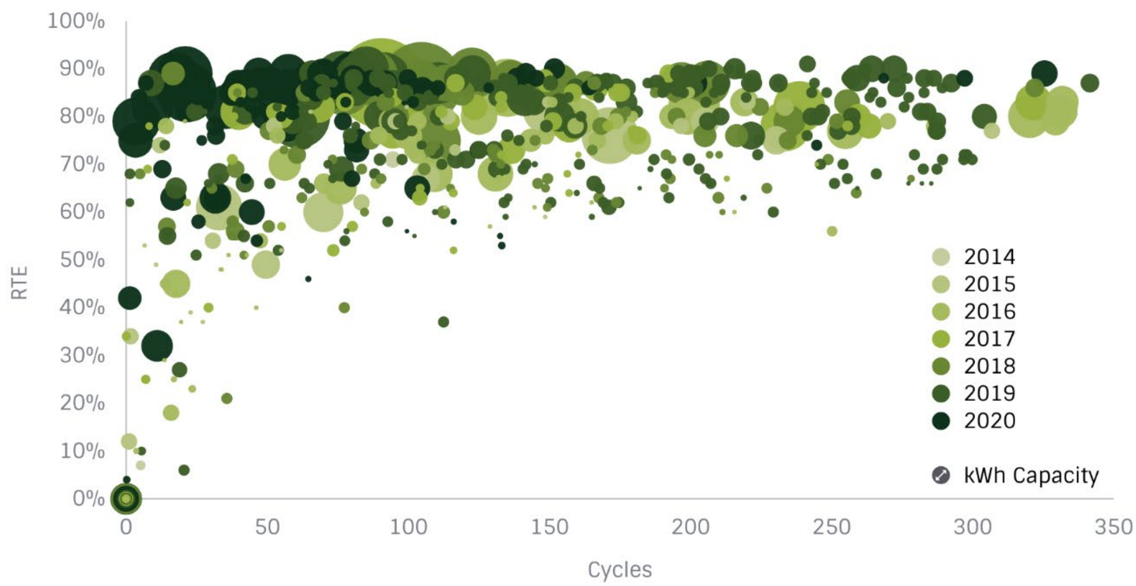
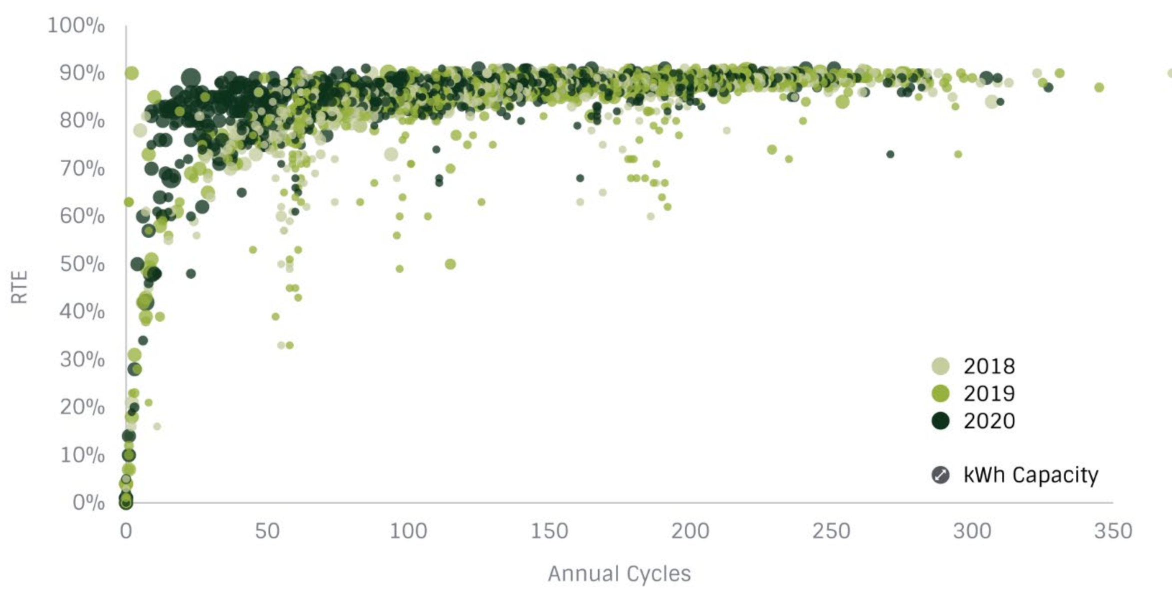


FIGURE 5-14: RTE VERSUS DISCHARGE CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE



5.1.4 Cross-Year Performance Impact Comparisons (2019 to 2020)

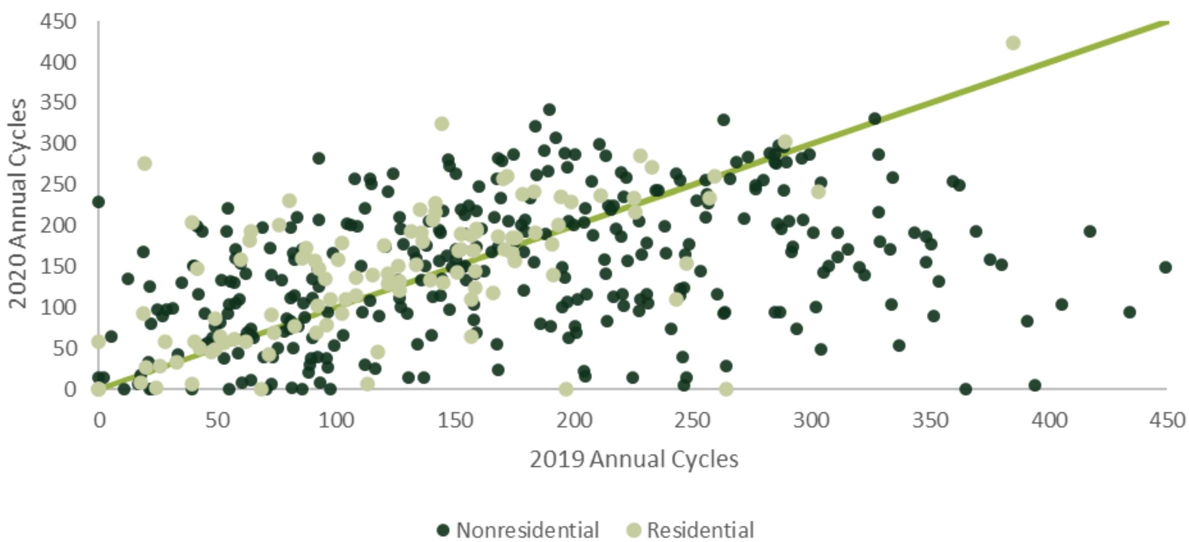
The evaluation team compared the performance metrics developed from the 2019 impact evaluation to those from this evaluation. These comparisons were made for system-level RTEs and utilization to highlight any potential changes in operation or utilization from one year to the next. Systems that came online during 2020 are not compared to projects in the 2019 population. Instead, the analysis is limited to the 113 residential systems and 336 nonresidential systems operational and sampled during both 2019 and 2020. It is important to note that many projects evaluated in 2019 received their upfront payments at different times throughout the year, so the 2019 performance metrics did not incorporate a full calendar year of impacts. All projects completed during 2019 were online and operating throughout the entirety of 2020, so any potential changes in performance from one year to the next may only reflect that difference.

Figure 5-15 and Figure 5-16 present those comparisons for RTEs and utilization. Any point on the figure above the green line represents a system with a greater RTE or utilization in 2020 than in 2019. Systems along the green line exhibit similar utilization and efficiencies in 2019 and 2020. Of the 113 residential systems, 87 had a greater RTE in 2020 relative to 2019, but in general, they were very similar. Seventy-eight of them increased their utilization in 2020. Roughly half of nonresidential systems were utilized less or were operating less efficiently in 2020 than they were in 2019.

While some of the nuances in these comparisons are attributable to systems being operational throughout the entirety of 2020 and only partially throughout 2019, reductions in utilization and efficiency may be explained by more relevant time-specific impacts like COVID. While the evaluation team could not confirm this, COVID impacts could have played a role in why nonresidential systems operating throughout both years were utilized less in 2020 and, on average, residential systems were utilized more often. Household consumption increased in March and April of 2020 as statewide shutdowns took hold. Systems may have been utilized more often to satisfy those increases in household demand throughout the day. Likewise, nonresidential building closures during that same period could have reduced facility load and the need to utilize the storage system more regularly and at greater magnitude of capacity.

FIGURE 5-15: CROSS-YEAR ROUNDTRIP EFFICIENCY COMPARISON (2019 TO 2020)

FIGURE 5-16: CROSS-YEAR DISCHARGE CYCLING COMPARISON (2019 TO 2020)



5.1.5 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 within these performance metrics from one evaluation year to the next as program requirements and objectives evolve and energy storage systems become more sophisticated and capable of operating in multiple modes. Below we summarize the performance metrics discussed above for both the nonresidential and residential sectors, respectively. Projects incented during 2020 are also presented differently depending on whether the project was legacy or non-legacy. All projects incented prior to 2020 are considered legacy since they received their upfront incentive payment prior to 4/1/2020.

TABLE 5-1: SUMMARY OF NONRESIDENTIAL PERFORMANCE METRICS

Upfront Incentive Year	Legacy Project	Sample n	Average Capacity (kWh)	Average Capacity Factor	RTE	Average Annual Cycles
2014	Yes	2	236	2%	60%	50
2015	Yes	33	775	3%	75%	90
2016	Yes	65	757	5%	78%	121
2017	Yes	62	614	5%	81%	117
2018	Yes	92	581	6%	82%	131
2019	Yes	234	402	7%	81%	158
2020	Yes	18	573	6%	87%	85
	No	84	778	5%	82%	65
Total		**590**	**570**	**6%**	**81%**	**126**

TABLE 5-2: SUMMARY OF RESIDENTIAL PERFORMANCE METRICS

Upfront Incentive Year	Legacy Project	Sample n	Average Capacity (kWh)	Average Capacity Factor	RTE	Average Annual Cycles
2018	Yes	538	16	6%	86%	129
2019	Yes	854	17	7%	86%	142
2020	Yes	250	18	7%	87%	139
	No	631	19	5%	86%	110
Total		**2,273**	**17**	**6%**	**86%**	**130**

5.2 CUSTOMER IMPACTS

Storage systems can be utilized for a variety of use cases, and dispatch objectives are predicated on several different factors including facility 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.

TOU periods 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[37]). Verdant conducted several different but concurrent analyses using the above TOU period descriptions along with customer rate schedules. The remainder of this section presents those results in more detail:

- Overall storage dispatch behavior based on TOU period and customer sector
- Overall storage dispatch behavior based on customer sector and presence of on-site generation
- Overall customer bill impacts ($/rebated kWh) by customer sector

5.2.1 Storage Dispatch Behavior by TOU Period and Customer Sector

Verdant analyzed the extent to which customers utilize their storage systems for TOU energy arbitrage and peak demand reduction. We observed a variety of storage use cases in 2020 which dictate the charge and discharge behaviors throughout the year. One analysis we conducted was to characterize TOU energy dispatch by quantifying the magnitude of storage discharge by TOU period. 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.

Figure 5-17 presents the average percentage of energy discharged throughout each of the three TOU periods and two seasons for residential and nonresidential systems. This analysis only includes weekdays during each of the seasonal definitions. Residential systems are discharging energy more often throughout on-peak hours than off-peak and super off-peak periods, while nonresidential systems discharge far less often during the on-peak period. 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 have inelastic demand during on-peak hours and that TOU arbitrage might not be the main causal mechanism of dispatch behavior. During both summer and winter periods, residential systems, on average, discharge 56% of energy during on-peak, while nonresidential systems are discharging more often during off-peak and super off-peak hours.

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

FIGURE 5-17: PERCENT DISCHARGE KWH BY TOU PERIOD AND CUSTOMER SECTOR

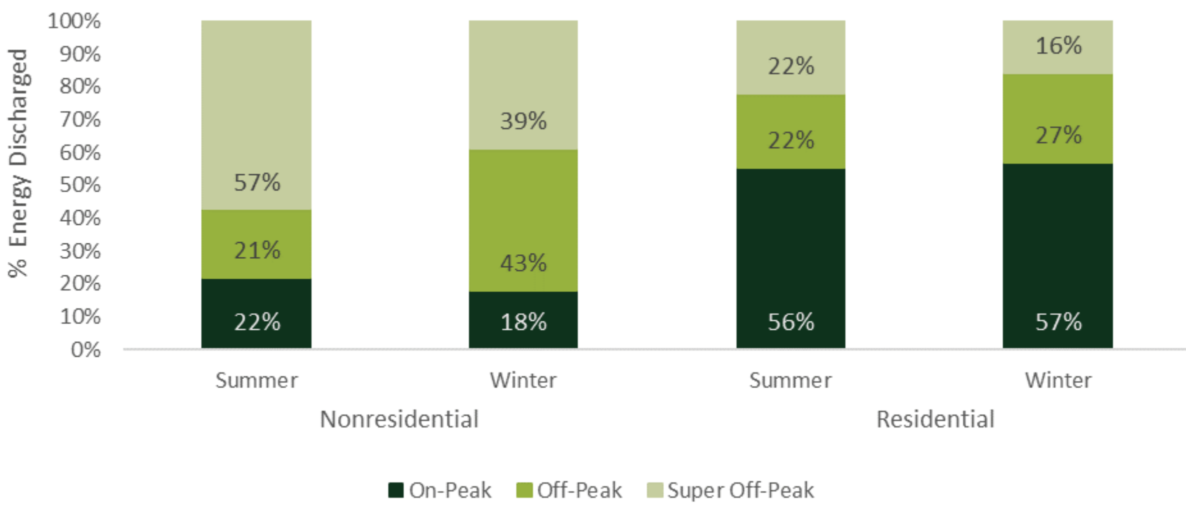
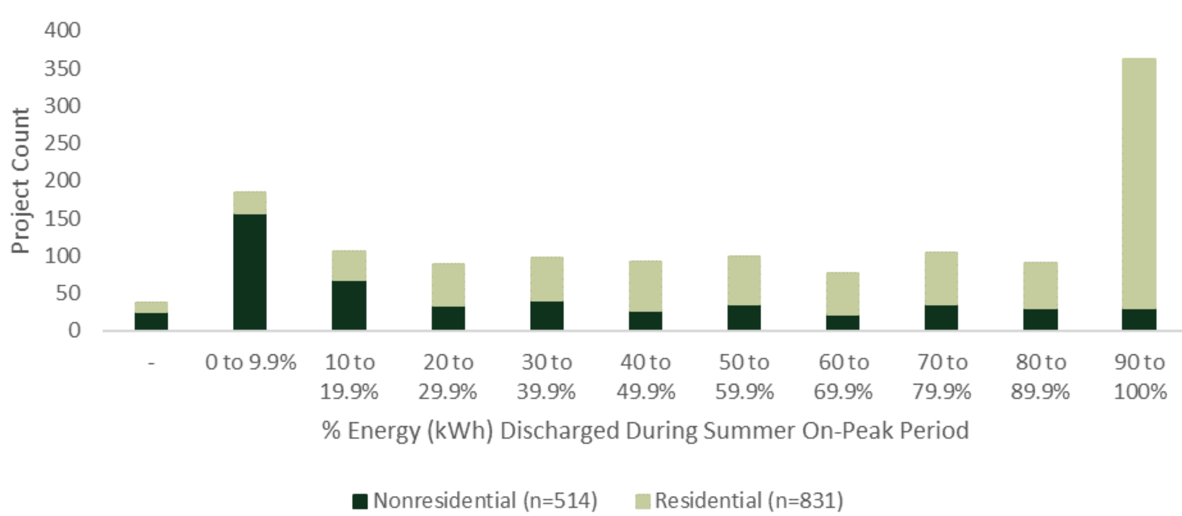


Figure 5-18 provides the distribution of systems discharging energy throughout the on-peak period only. As evident from the far right of the figure, roughly 40 percent of residential customers on a TOU rate are discharging greater than 90 percent of energy during on-peak, relative to all other rate periods. The behavior of nonresidential systems is the inverse, with almost 31 percent of customers discharging less than 10% of the kWh capacity throughout on-peak times. This figure lends evidence that nonresidential and residential customers are utilizing their storage systems in very different manners from a TOU perspective.

FIGURE 5-18: PERCENT KWH DISCHARGE DURING ON-PEAK PERIOD BY CUSTOMER SECTOR

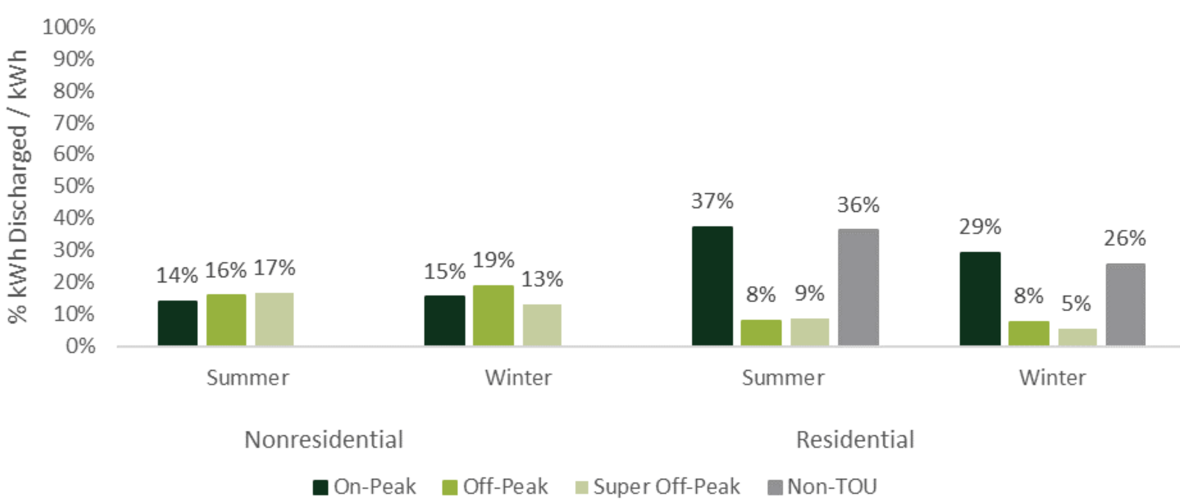


The previous exhibits provide evidence that most residential storage systems are discharging more often during on-peak periods relative to off- and super off-peak periods, and nonresidential systems are largely ignoring the energy price differential across periods and discharging more often outside on-peak periods. Next, we examine the magnitude of energy discharge throughout these TOU 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 5-19 presents the average magnitude of energy discharge during each season and period as a percentage of the total capacity of the system. It's important to note that this analysis sums the energy discharged across each customer's on-peak period, so the sum of energy discharged for a customer subject to a 5 hour on-peak period is treated the same as a customer subject to a 2 hour or 6 hour on-peak period.

On average, residential systems on a TOU rate are discharging 37% of system capacity during on-peak periods throughout the summer. They are also discharging during off- and super off-peak periods, but at much lower magnitudes of available capacity. Residential systems labeled "Non-TOU" are those still on a tiered volumetric rate during 2020. These rates do not contain any peak period definition, so 36% in summer represents the average system discharge throughout the entire day. Evident once again, is the lower magnitude of system discharge relative to capacity for nonresidential systems during on-peak periods. On average, these systems are discharging 14 percent of total available energy throughout summer on-peak periods – which is a similar magnitude being discharged during off- and super off-peak hours.

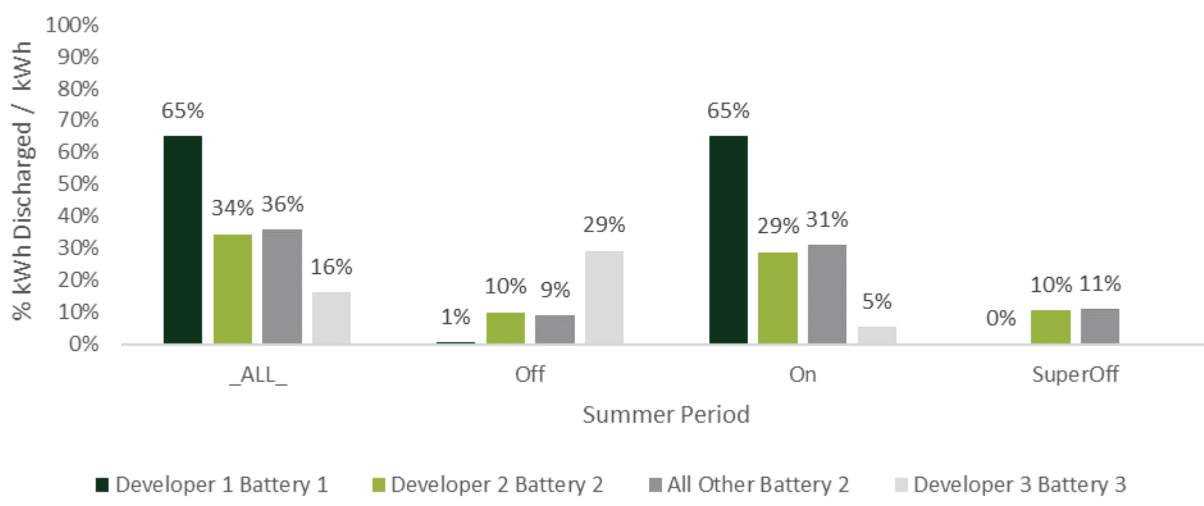
FIGURE 5-19: NET DISCHARGE KWH PER CAPACITY KWH BY TOU PERIOD



We further examine residential storage discharge behavior when disaggregating by project developer and battery manufacturer. Our analysis has revealed – not surprisingly – 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 5-20 presents the average discharge as a percentage of kWh capacity for the three main manufacturers of residential energy storage systems disaggregated by project developer type. Developer 1 is the largest developer installing Battery 1 in 2020. This is true for Developer 2 installing Battery 2 and the lone developer utilizing Battery 3. The "All Other" Battery 2 represents all other developers (or channel partners to Developer 2) who installed Battery 2.[38] As evident in the figure, Developer 1 Battery 1 is discharging a greater percentage of available capacity (65% during on-peak summer hours) than the other developers and battery manufacturers. They are also not discharging throughout off- and super off-peak hours. It's also important to note that discharge magnitudes for Developer 2 of Battery 2 are almost identical to the discharge magnitudes of systems installed by other developers. These systems discharge 29 to 31% of available kWh capacity throughout on-peak periods but continue to discharge outside of those hours. These patterns suggest blended discharge behavior and multiple use cases – TOU arbitrage as well as self-consumption.

FIGURE 5-20: NET DISCHARGE KWH PER CAPACITY KWH BY TOU PERIOD AND DEVELOPER/MANUFACTURER



[38] Developer names and battery manufacturers have been anonymized for confidentiality purposes.

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. Below we examine the timing of aggregated storage dispatch to further understand how storage systems are being utilized throughout the year. We performed this analysis by taking the average hourly charge and discharge kWh as a percentage of system kWh capacity for each month and hour within the year for residential and nonresidential systems. Figure 5-21 and Figure 5-22 present the findings for residential systems. The data are presented in hour beginning and Pacific Standard Time (PST).

These data follow the pattern presented above. Residential systems, on average, are discharging the most significant percentage of energy during the 3 pm PST hour (4 pm Pacific Daylight Time (PDT)). 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 are almost exclusively charging during early morning hours, which coincides with early PV generation hours. This will be discussed in Section 5.3.2.

FIGURE 5-21: AVERAGE HOURLY DISCHARGE (KWH) PER CAPACITY (KWH) FOR RESIDENTIAL SYSTEMS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	1%	0%
1	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%
2	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
3	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
4	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
5	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
6	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	0%
13	0%	0%	1%	1%	2%	2%	2%	2%	2%	2%	1%	0%
14	1%	1%	1%	2%	2%	2%	2%	3%	3%	2%	2%	1%
15	2%	1%	3%	4%	5%	10%	10%	11%	10%	6%	2%	2%
16	4%	4%	4%	4%	5%	7%	8%	8%	8%	7%	5%	4%
17	5%	5%	4%	4%	5%	5%	5%	5%	5%	5%	8%	7%
18	4%	5%	4%	4%	4%	5%	5%	4%	4%	4%	5%	4%
19	3%	4%	3%	3%	4%	4%	4%	3%	3%	3%	4%	3%
20	2%	3%	2%	2%	3%	3%	3%	2%	2%	2%	3%	2%
21	1%	2%	2%	2%	2%	2%	2%	2%	1%	1%	2%	1%
22	1%	2%	1%	1%	2%	2%	1%	1%	1%	1%	1%	1%
23	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

FIGURE 5-22: AVERAGE HOURLY CHARGE (KWH) PER CAPACITY (KWH) FOR RESIDENTIAL SYSTEMS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	-1%	-2%	-2%	-2%	-1%	-1%	0%	0%	0%
7	-1%	-1%	-2%	-4%	-6%	-6%	-6%	-5%	-4%	-3%	-2%	-1%
8	-3%	-4%	-5%	-7%	-9%	-10%	-10%	-9%	-8%	-6%	-5%	-3%
9	-6%	-8%	-7%	-8%	-9%	-10%	-12%	-11%	-10%	-8%	-8%	-6%
10	-7%	-8%	-7%	-7%	-7%	-8%	-9%	-9%	-9%	-9%	-8%	-7%
11	-6%	-7%	-5%	-5%	-4%	-6%	-6%	-6%	-6%	-7%	-7%	-7%
12	-4%	-5%	-4%	-3%	-3%	-3%	-4%	-4%	-4%	-4%	-5%	-5%
13	-3%	-3%	-2%	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-3%	-3%
14	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
15	-1%	-1%	-1%	0%	-1%	-1%	-1%	-1%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Nonresidential systems, conversely, exhibit more variability in charge and discharge behavior throughout the day. Figure 5-23 and Figure 5-24 convey these results. The magnitude of charge and discharge kWh are similar across some hours throughout the day. The data provide evidence that nonresidential systems are discharging during peak periods, but also during off-peak and super off-peak periods. There appear to be no discernible reasons for this pattern of charge/discharge during the late evening and early morning hours from a bill savings perspective. However, this behavior does increase the utilization of the system.

Also present is a distinct charging pattern in the morning much like that of residential systems. A large fleet of storage systems paired with PV have been installed and rebated in primary and secondary schools. As presented in Figure 3-9, schools represent roughly 23% of the total nonresidential program kWh capacity, so the weight and impacts of these systems can be gleaned from the overall sector level impacts. The pattern of discharge in Figure 5-23 from 4 – 6 am also follow the load shapes of schools. Morning ramps are being flattened by storage discharge prior to on-site PV generating hours.

FIGURE 5-23: AVERAGE HOURLY DISCHARGE (KWH) PER CAPACITY (KWH) FOR NONRESIDENTIAL SYSTEMS

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	1%	1%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%
1	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
2	1%	1%	1%	2%	2%	2%	1%	1%	1%	1%	1%	1%
3	1%	1%	1%	2%	2%	2%	2%	1%	1%	1%	1%	1%
4	1%	1%	2%	2%	3%	3%	3%	2%	1%	1%	1%	1%
5	1%	1%	2%	3%	3%	3%	3%	2%	1%	1%	1%	1%
6	2%	3%	3%	3%	3%	2%	2%	2%	1%	2%	1%	2%
7	3%	3%	2%	1%	1%	1%	1%	1%	1%	1%	1%	2%
8	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
9	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
10	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
11	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
12	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
13	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
14	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
15	1%	1%	1%	1%	2%	2%	2%	3%	2%	2%	1%	1%
16	2%	2%	1%	1%	3%	3%	3%	4%	3%	3%	2%	2%
17	3%	3%	2%	2%	2%	2%	2%	3%	3%	3%	3%	3%
18	3%	4%	4%	4%	4%	3%	4%	4%	3%	3%	3%	3%
19	3%	4%	5%	6%	5%	5%	6%	5%	5%	5%	3%	3%
20	5%	6%	4%	4%	3%	3%	3%	2%	2%	2%	5%	4%
21	3%	3%	2%	2%	2%	2%	2%	1%	1%	1%	2%	2%
22	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%
23	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

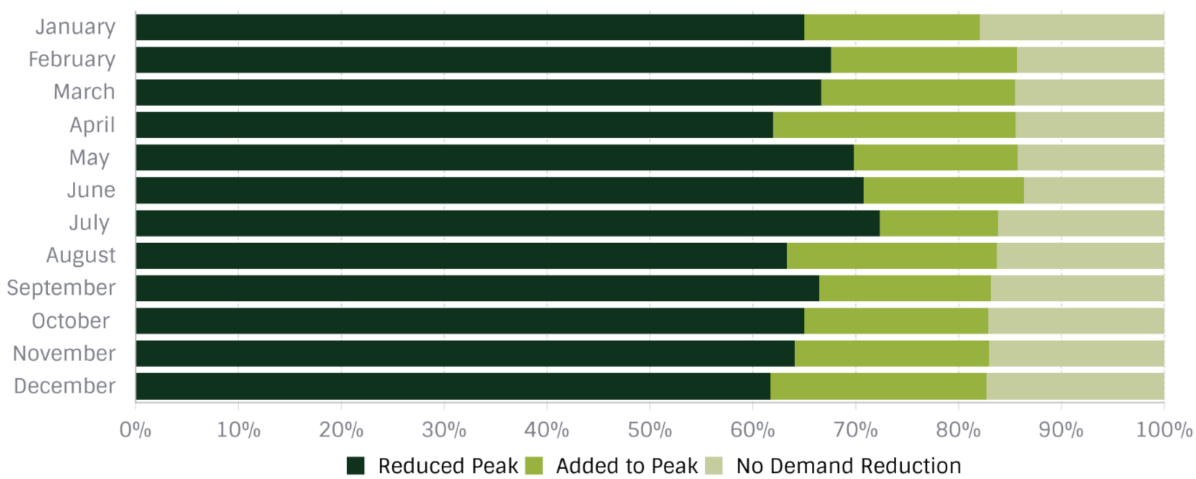
FIGURE 5-24: AVERAGE HOURLY CHARGE (KWH) PER CAPACITY (KWH) FOR NONRESIDENTIAL SYSTEMS

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	-3%	-3%	-3%	-2%	-2%	-3%	-3%	-3%	-2%	-2%	-2%	-2%
1	-3%	-3%	-2%	-2%	-2%	-2%	-3%	-2%	-2%	-2%	-2%	-2%
2	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-2%
3	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%
4	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%
5	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-1%	-1%	-1%
6	-1%	-1%	-1%	-2%	-3%	-3%	-3%	-2%	-1%	-1%	-1%	-1%
7	-1%	-2%	-4%	-5%	-7%	-4%	-4%	-3%	-3%	-4%	-2%	-1%
8	-4%	-5%	-6%	-7%	-8%	-5%	-5%	-4%	-4%	-5%	-5%	-4%
9	-6%	-6%	-6%	-6%	-6%	-5%	-5%	-4%	-4%	-5%	-6%	-5%
10	-6%	-6%	-5%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-5%	-5%
11	-5%	-5%	-3%	-3%	-2%	-2%	-2%	-3%	-2%	-3%	-3%	-4%
12	-4%	-3%	-2%	-2%	-1%	-2%	-1%	-2%	-1%	-2%	-2%	-3%
13	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%
14	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
15	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
16	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
17	0%	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
18	-1%	0%	0%	0%	-1%	-1%	0%	-1%	-1%	0%	0%	0%
19	0%	0%	-1%	-1%	-1%	-1%	0%	-1%	-1%	0%	0%	0%
20	-1%	-1%	-2%	-2%	-3%	-5%	-5%	-4%	-4%	-2%	0%	-1%
21	-3%	-3%	-3%	-3%	-4%	-5%	-5%	-5%	-4%	-3%	-2%	-3%
22	-4%	-5%	-4%	-2%	-3%	-3%	-3%	-4%	-3%	-2%	-2%	-2%
23	-3%	-3%	-3%	-3%	-3%	-4%	-4%	-4%	-3%	-3%	-2%	-2%

We also examined the impact of storage discharge on demand or power (kW). If the 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 5-25 and Figure 5-26 convey the percentage of nonresidential and residential customers who either 1) reduced their monthly peak demand, 2) added to their peak or 3) experienced no demand increase with how they utilized their energy storage system.[39] As expected, commercial customers reduced their non-coincident monthly peak demand more frequently throughout the year than residential customers. 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. We also observe a greater percentage of projects reducing facility peak demand throughout May, June, and July. This may correspond to increases in summer demand charges ($/kW).

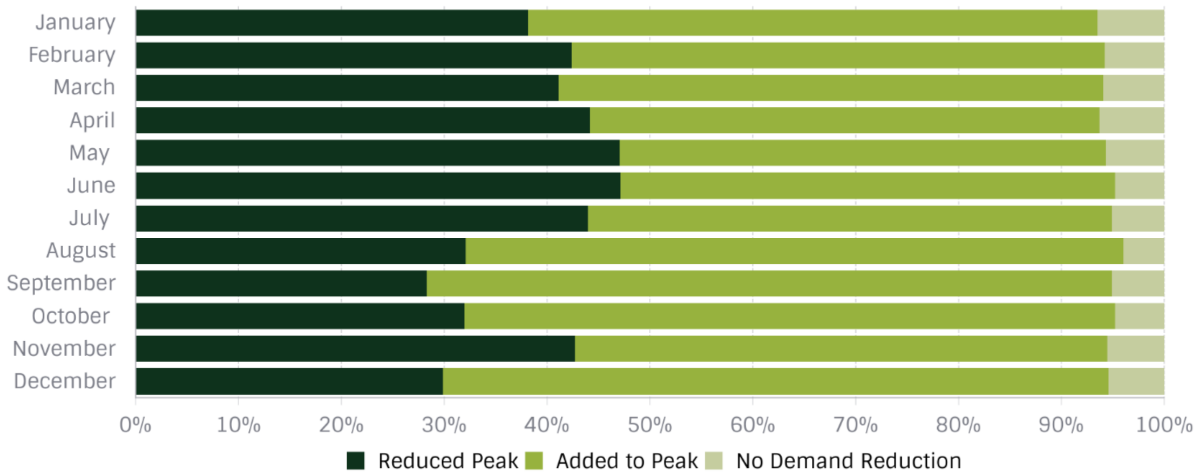
FIGURE 5-25: DISTRIBUTION OF MONTHLY NONRESIDENTIAL PEAK DEMAND IMPACTS



Residential customers are not subject to demand charges, so any peak reductions are just coincident to how they're dispatching the system throughout the day. However, we do observe more systems increasing load in August – October and December relative to other months throughout the year.

[39] These analyses assume the baseline methodology that was discussed in Section 5 and presented in Figure 5-1.

FIGURE 5-26: DISTRIBUTION OF MONTHLY RESIDENTIAL PEAK DEMAND IMPACTS



We also examined the monthly peak demand reductions relative to the rebated capacity of the system and the overall reduction in demand. This involves taking the difference of the highest 15-minute power (kW) reading in the absence of storage and the actual highest reading during each customer bill period. That measure was then normalized by the kW capacity of the system. A customer would presumably realize demand bill savings as the difference between the observed and counterfactual case.

Figure 5-27 conveys the results of that analysis. Throughout the year, nonresidential systems are reducing monthly demand as a percentage of rebated capacity more than residential systems. The average customer peak demand reduction is 16 percent of SGIP rebated capacity for nonresidential systems and 7 percent for residential systems. We observe a greater peak demand reduction for nonresidential customers, on average, within the summer months (20% average demand reduction in July) and we observe lower reductions in March and April. These months align well with initial COVID shutdown protocols, so businesses who closed during that period may have reduced load and utilized their system less for peak demand reductions. It's important to note, residential systems are not subject to demand charges and exhibit longer low energy duration discharges than nonresidential systems, but we do observe much lower peak demand reductions in August – October and December, which is consistent with the more prevalent increases in load during those months as presented in Figure 5-26.

FIGURE 5-27: MONTHLY PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

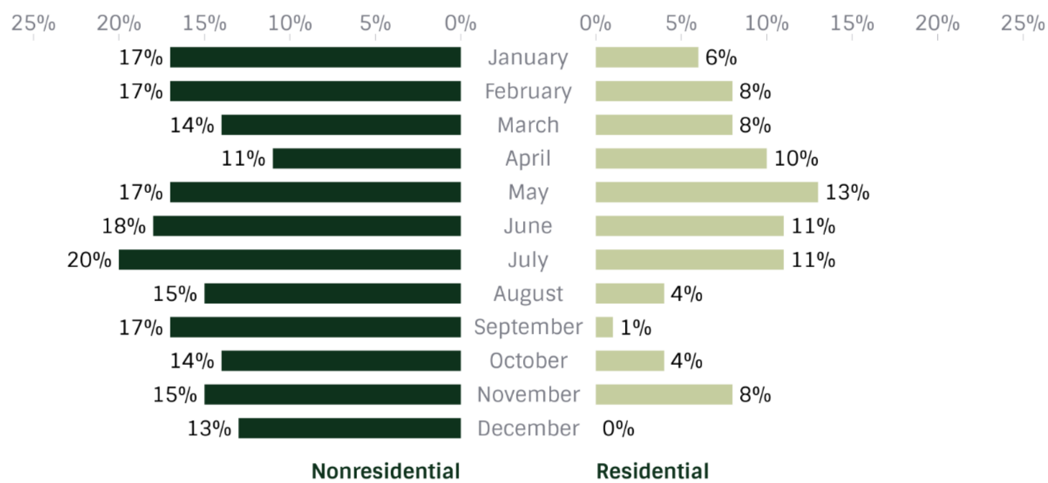
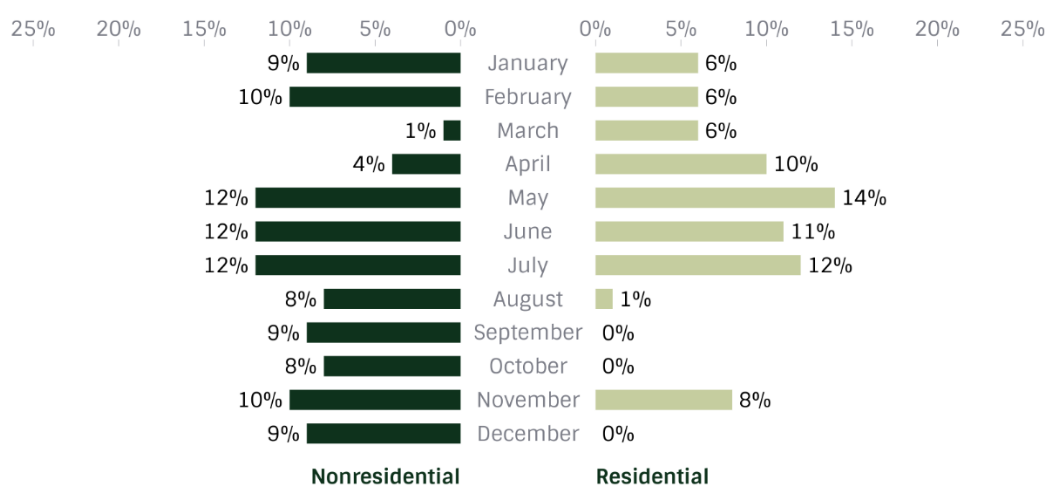


Figure 5-28 conveys the monthly average peak demand reduction as a percentage of the monthly avoided peak. In other words, if a customer's monthly peak demand would have been 100 kW in the absence of the storage system – this value is calculated and not metered – and they reduced peak demand by 10 kW with storage, then the customer reduced their peak demand by 10 percent. On average, nonresidential customers are reducing their peak demand by 9 percent and residential customers are reducing their peak demand by 5 percent.

FIGURE 5-28: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW)

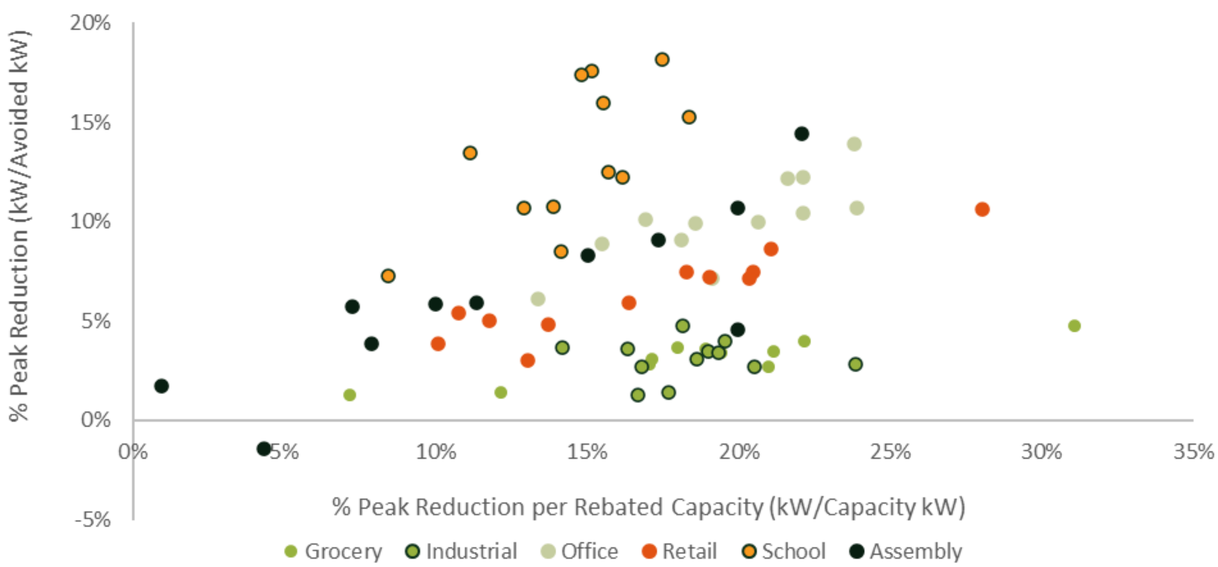


*This figure assumes a minimum value of zero. For September, October and December, residential systems increased their peak demand, on average, compared to a baseline of no energy storage.

Figure 5-29 disaggregates the data provided in the above figures for each month and nonresidential facility type. The horizontal axis represents the monthly peak demand reduction, as a percentage of rebated capacity, for each system-month and the vertical axis represents the monthly peak demand reduction for each system relative to their avoided peak demand for that month.

While the average peak demand reduction is 16 percent of SGIP rebated capacity for nonresidential systems, the distribution by month ranges from as high as 31 percent for grocery stores in February of 2020 to as low as a one percent increase for Assembly in April.[40] Larger nonresidential systems are utilizing a small percentage of their storage capacity to reduce monthly peaks. However, given the size of the systems relative to the load they service, the average monthly peak demand reductions – as a function of peak facility load – are akin to residential systems.

FIGURE 5-29: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) BY CUSTOMER TYPE



5.2.2 Storage Dispatch Behavior with On-site Generation

The previous section provided evidence that residential storage systems are conducting some TOU arbitrage, while the discharge patterns outside IOU rate defined on-peak periods also suggests this is not

40 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.

the only motivation and use case for residential customers. Nonresidential system charge and discharge behavior suggests they are conducting non-coincident and coincident peak demand reduction at the expense of TOU arbitrage. However, each of these analyses focused almost exclusively on discharge.

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 is available to customers installing storage if the storage system is only charged by on-site generation like solar. For nonresidential customers, the ITC is available if the storage system is charging from on-site generation more than 75 percent of the time. We reviewed the 15-minute kWh storage charge data for each system in the SGIP sample and compared that to 15-minute kWh PV generation data, where available. Our team did not receive PV generation data for all projects. We relied on reviewing the net load for customers to provide evidence of PV generation where actual PV generation data was missing. The same was done for nonresidential systems.

Figure 5-30 presents the percentage of energy charged from (or during) PV generation compared to the energy charged outside of PV generating hours. This analysis relied on data where we had PV generation data to compare against. Overall, residential systems in 2020 charged exclusively from/during PV generation (99.6%) and a similar pattern is evident for nonresidential systems (96.0%). We observed roughly 30 percent of nonresidential systems paired with on-site PV. All but five residential systems were paired.

FIGURE 5-30: PERCENT CHARGE KWH DURING PV GENERATION BY CUSTOMER SECTOR

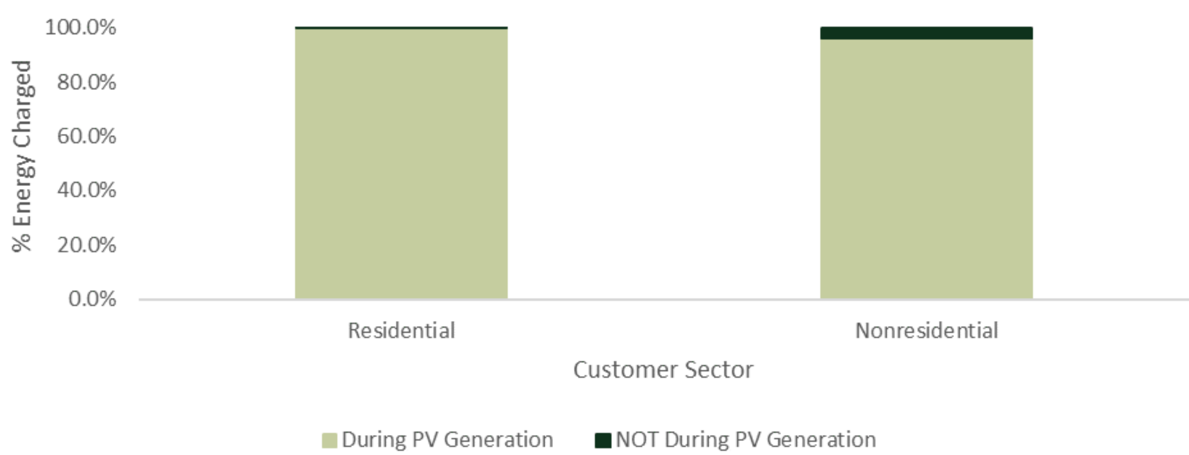


Figure 5-31 and Figure 5-32 present the average hourly net discharge kWh as a percentage of available system capacity kWh for each hour within the day and month throughout the year for nonresidential projects. Net discharge kWh is provided, along with whether the systems were paired or co-located with on-site PV. Nonresidential systems without PV represent a variety of facility types, but the average net discharge is positive for a couple of early afternoon hours in the summer, and these systems are net charging more substantially after 7 pm PST and throughout early morning hours.

FIGURE 5-31: AVERAGE NET DISCHARGE (KWH) PER CAPACITY (KWH) FOR NONRESIDENTIAL SYSTEMS (NO PV)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	-2%	-2%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-2%	-1%
1	-2%	-2%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%
2	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
3	-1%	-1%	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	-1%
4	-1%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%
5	0%	0%	1%	1%	0%	0%	0%	1%	0%	0%	0%	0%
6	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	1%
7	1%	1%	-2%	-3%	-3%	-1%	-1%	-1%	0%	-2%	0%	1%
8	-2%	-2%	-2%	-2%	-3%	-1%	-1%	-1%	-1%	-2%	-3%	-2%
9	-2%	-2%	-2%	-2%	-2%	-1%	-1%	0%	-1%	-1%	-2%	-2%
10	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	-1%	-1%	-1%
11	-1%	-1%	0%	-1%	0%	0%	0%	0%	0%	0%	-1%	-1%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%
15	0%	0%	0%	1%	2%	2%	3%	3%	2%	2%	0%	0%
16	1%	1%	1%	1%	3%	3%	4%	4%	3%	3%	1%	1%
17	2%	2%	1%	1%	1%	1%	1%	2%	1%	2%	2%	2%
18	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
19	3%	3%	4%	5%	4%	4%	4%	4%	4%	4%	2%	2%
20	5%	5%	2%	0%	-1%	-3%	-3%	-3%	-3%	-1%	4%	3%
21	-1%	-1%	-1%	-2%	-2%	-4%	-4%	-4%	-3%	-3%	-1%	-1%
22	-4%	-4%	-2%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-2%	-2%
23	-2%	-2%	-2%	-2%	-2%	-3%	-3%	-3%	-3%	-3%	0%	-1%

FIGURE 5-32: AVERAGE NET DISCHARGE (KWH) PER CAPACITY (KWH) FOR NONRESIDENTIAL SYSTEMS (WITH PV)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	0%	0%	0%	1%	1%	1%	1%	0%	-1%	0%	0%	0%
1	0%	0%	0%	1%	2%	2%	1%	0%	0%	0%	0%	0%
2	0%	0%	1%	2%	2%	2%	2%	0%	0%	0%	0%	0%
3	0%	0%	1%	3%	3%	3%	2%	1%	0%	0%	0%	0%
4	1%	1%	2%	4%	4%	4%	3%	2%	1%	0%	1%	1%
5	2%	2%	3%	4%	4%	3%	4%	3%	1%	1%	2%	2%
6	3%	3%	3%	-1%	-4%	-2%	-1%	0%	0%	1%	2%	2%
7	3%	3%	-3%	-8%	-11%	-8%	-8%	-5%	-5%	-4%	-2%	1%
8	-3%	-5%	-10%	-15%	-16%	-13%	-12%	-10%	-9%	-8%	-9%	-5%
9	-11%	-12%	-13%	-14%	-14%	-13%	-13%	-11%	-11%	-11%	-13%	-12%
10	-15%	-15%	-11%	-9%	-8%	-9%	-10%	-9%	-9%	-10%	-13%	-14%
11	-13%	-13%	-7%	-5%	-4%	-6%	-5%	-6%	-5%	-7%	-8%	-11%
12	-9%	-7%	-4%	-3%	-2%	-3%	-2%	-3%	-2%	-4%	-4%	-7%
13	-4%	-3%	-2%	-2%	-1%	-2%	-1%	-1%	0%	-1%	-1%	-3%
14	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	-1%
15	0%	0%	-1%	0%	-1%	-1%	-1%	-1%	0%	0%	1%	0%
16	2%	1%	1%	0%	0%	1%	1%	1%	2%	3%	2%	2%
17	4%	4%	3%	3%	2%	1%	2%	4%	3%	4%	3%	3%
18	5%	5%	4%	5%	6%	5%	5%	6%	5%	5%	4%	4%
19	5%	6%	5%	5%	5%	6%	6%	5%	5%	5%	5%	5%
20	5%	6%	5%	5%	5%	5%	5%	5%	5%	4%	5%	5%
21	4%	5%	3%	3%	3%	3%	2%	2%	2%	2%	4%	4%
22	2%	1%	3%	5%	5%	4%	3%	4%	3%	4%	2%	1%
23	3%	3%	1%	1%	1%	1%	1%	0%	-1%	0%	3%	3%

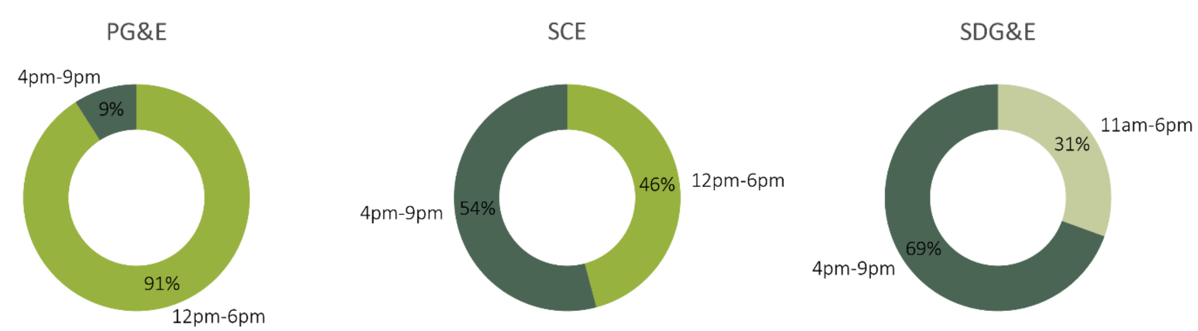
5.2.3 Overall Storage Dispatch Behavior by Customer Rate Group

This section expands upon the analysis conducted in the prior section by introducing customer bill rate schedules. The evaluation team utilized the customer rate schedules to analyze how storage dispatch behavior is associated with different rates. There were 42 unique customer rates from the SGIP sample of nonresidential systems across all PAs and all customers in the sample with a verified rate schedule were on some type of TOU schedule with demand charges:

- 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 5-33 presents the proportion of the different peak periods for the TOU rates for each of the IOUs. It's important to note, these distributions represent all the rates we analyzed throughout 2020 by month. A customer who may have been on one TOU rate early in 2020 and transitioned over to another TOU rate with a different peak period at some point throughout the year would be represented in both appropriate peak slices below.

FIGURE 5-33: DISTRIBUTION OF PEAK PERIODS FOR NONRESIDENTIAL CUSTOMERS (BY IOU)



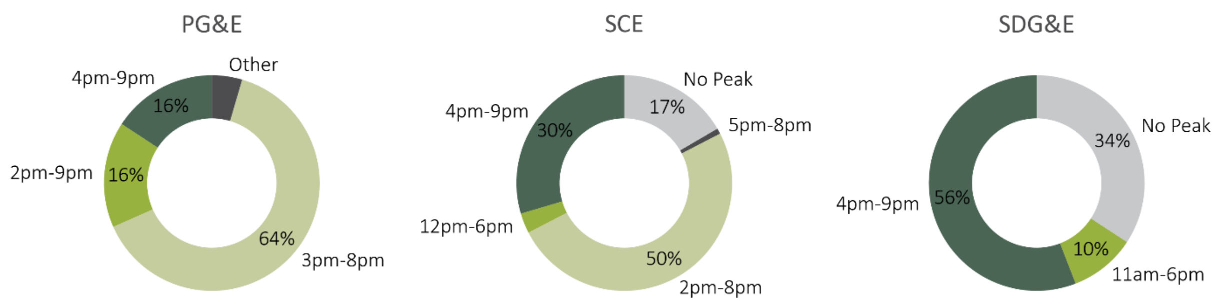
There were 29 unique customer rates from the sample of residential systems across IOUs. Residential customers with a verified rate schedule were on some type of volumetric or TOU energy rate in 2020:

- 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 a 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 5-34 presents the proportion of TOU rates versus non-TOU volumetric rates for each of the IOUs. It's important to note, these distributions represent all the rates we analyzed throughout 2020 by month. A customer who may have been on a volumetric rate early in 2020 and transitioned over to a TOU rate at some point throughout the year would be represented in both the non-TOU and the appropriate peak slice below.

FIGURE 5-34: DISTRIBUTION OF TOU VS NON-TOU RATES FOR RESIDENTIAL CUSTOMERS (BY IOU)

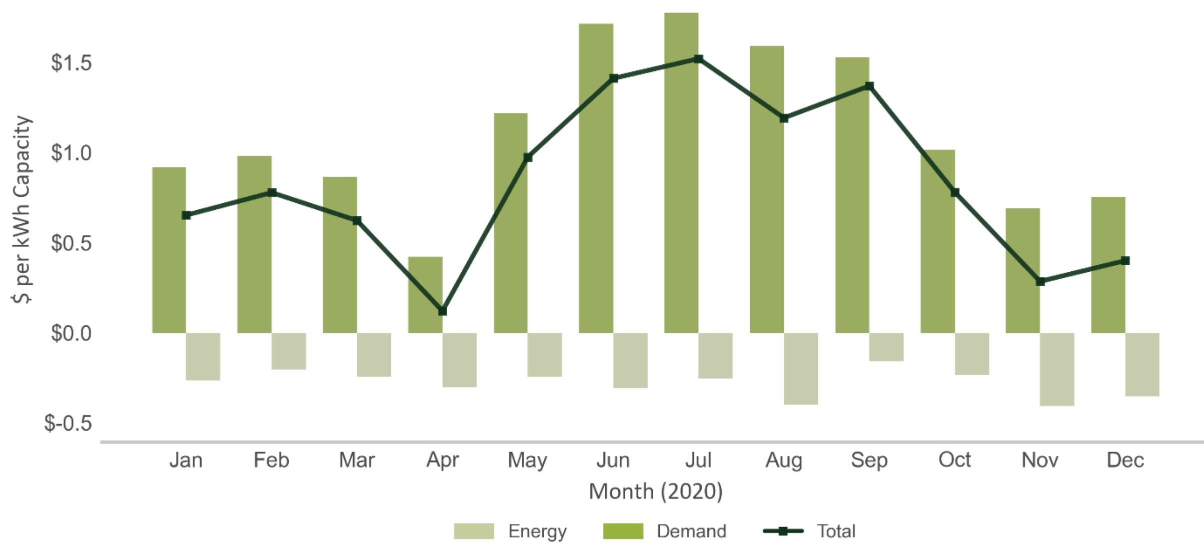


Overall Customer Bill Savings ($/kWh) by Rate Group and Customer Sector

We combined the energy rates charged during each of the TOU periods and compared the observed energy consumption with storage to energy consumption without storage to develop bill impact estimates for customers. 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 specific customer rate schedule. The expectation is that customers on a TOU energy only rate are discharging during periods when energy rates are high and charging during periods of lower prices which would translate into bill savings. For customers with demand charges, the expectation is that they are optimizing either monthly facility demand charge reduction or peak period demand charge reduction, perhaps, at the expense of TOU energy arbitrage. Figure 5-35 presents the results for nonresidential customers by month. The vertical axis represents the average monthly savings (or increased cost) in dollars, normalized by the capacity kWh of the storage system.

Nonresidential customers incurred energy costs, on average, by utilizing their storage systems throughout 2020. However, they realized significant savings by utilizing their storage to reduce peak and/or monthly demand. This is especially true throughout summer months when both energy and demand charges are greatest.

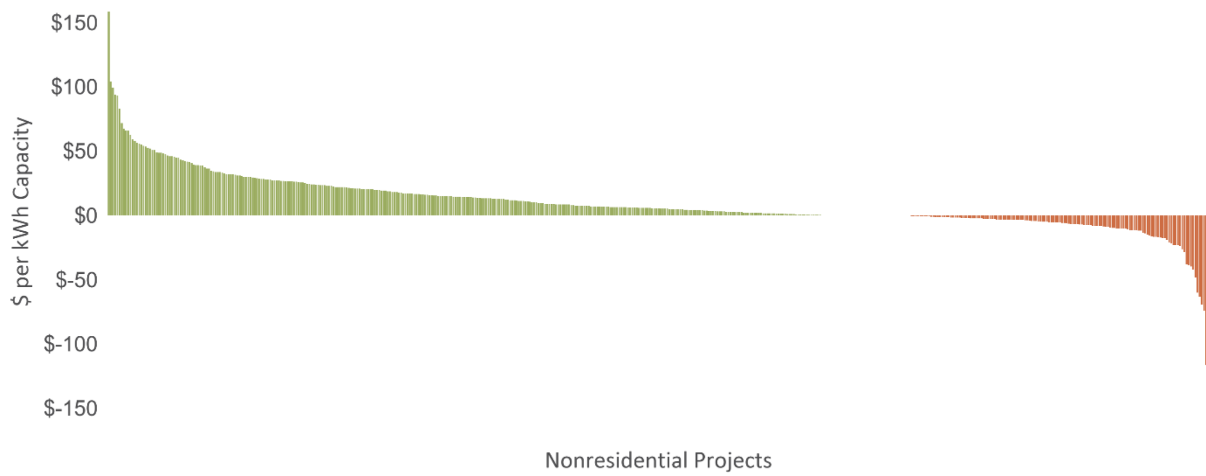
FIGURE 5-35: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH



*On average, nonresidential customers see a savings from demand charges that range from $0.42/kWh to $1.79/kWh per month, while they see a slight increase in their bills due to energy charges, which are mostly consistent across the year, between $0.15/kWh to $0.41/kWh. The overall effect on the customer's bill comes out to a total savings of between $0.11/kWh to $1.53/kWh, with the lowest savings seen in April and the other winter months, and the highest savings observed during July and other summer months.

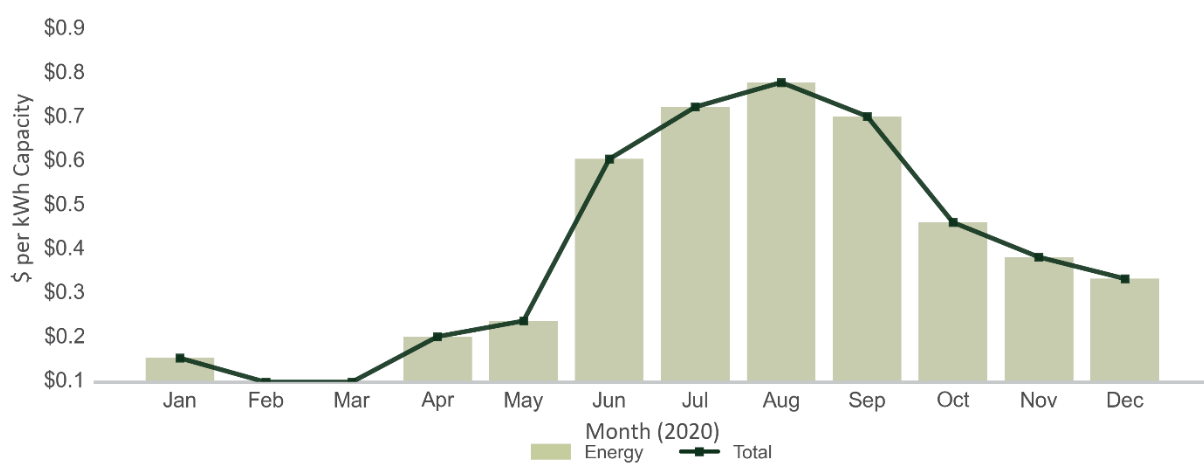
Figure 5-36 presents the distribution of total bill savings for each nonresidential storage participant, sorted by greatest savings to least savings (or an overall bill increase). Nonresidential customers, on average, realized bill savings around $9 per system capacity kWh.

FIGURE 5-36: DISTRIBUTION OF NONRESIDENTIAL OVERALL CUSTOMER BILL SAVINGS ($/KWH)



Residential customers are not subject to demand charges, so charges accrue from customer energy consumption. Figure 5-37 presents the average monthly bill savings (or increased cost) for residential customers. As previously mentioned, residential customers are utilizing their storage systems much more during summer months, which coincides with periods of higher price per kWh. While winter months saw much lower savings, on average, residential customers saw bill savings throughout the year.

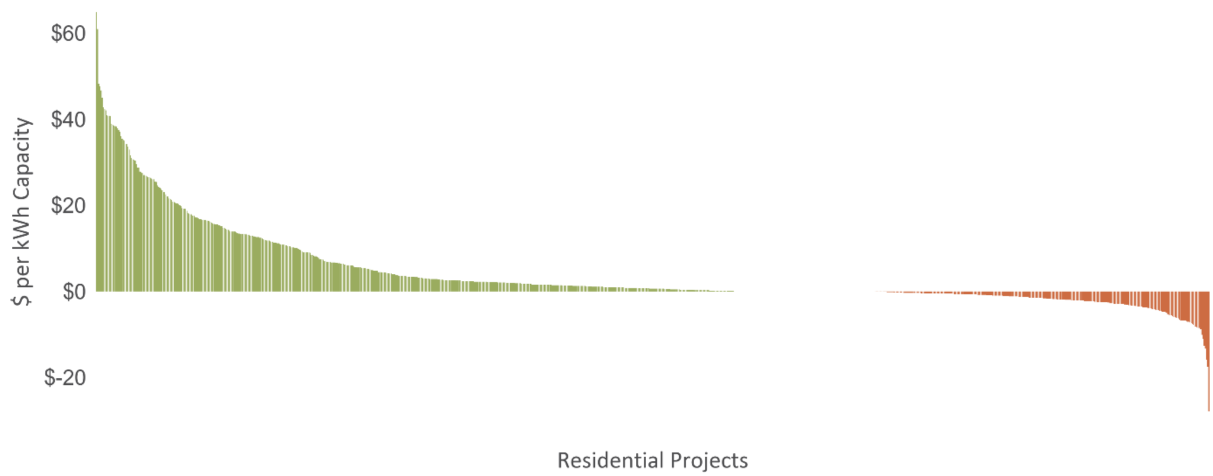
FIGURE 5-37: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH



*On average, residential customers see a savings from energy charges that range from $0.09/kWh to $0.77/kWh per month, with the lowest savings seen the first half of the year, and the highest savings seen during August and other summer months.

Figure 5-38 presents the distribution of total bill savings for residential customers, sorted by greatest savings to least savings (or an overall bill increase). Across the year, residential customers realized bill savings of roughly $4 per system capacity kWh. However, the range of bill savings and bill increases is substantial. Bill savings range from as high as $65 per rebated capacity kWh to as low as -$28 per rebated capacity kWh (a bill increase). There were 33 residential customers on a non-TOU rate that saw an average bill savings of about $1.50 per rebated capacity kWh, while there were 95 customers on a non-TOU rate that saw an average bill increase of about $2.60 per rebated capacity kWh.

FIGURE 5-38: DISTRIBUTION OF RESIDENTIAL OVERALL CUSTOMER BILL SAVINGS ($/KWH)



5.3 CAISO AND IOU SYSTEM IMPACTS

As a load shifting technology, the timing and magnitude of storage dispatch throughout the year can also have an impact on the electricity grid. As detailed above, SGIP nonresidential storage systems are generally being utilized to reduce non-coincident monthly peak demand and, to a much lesser extent, TOU energy arbitrage. They incur increases on the energy component of their bill, but demand reduction savings lead to a net decrease in bills overall. Residential storage systems are being utilized for TOU arbitrage and to maintain zero net load throughout the day. 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 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 200 gross and net peak demand hours in 2020 for the CAISO system.[41]

5.3.1 CAISO System Impacts

The evaluation team 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 2020. 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 can be disruptive from a planning perspective.

The correct timing of energy storage discharge and charge can ease that transition and alleviate that disruption. Figure 5-39 and Figure 5-40 provide two example CAISO load days. Figure 5-39 represents a typical spring day where there is evidence of an early morning ramp, followed by a drop in net load throughout the day and an early evening ramp. Renewable generation (especially solar) hours align well with increases in demand, as demand for such energy-intensive on-site technologies like air conditioning are minimal.

[41] The top 200 CAISO gross peak hours extend across 33 days and all fall within summer months (6/3 through 10/2). The CAISO gross peak in 2020 occurred on August 18th during the 2 pm PST hour. The top 200 net hours extend across 48 days and all fall within 5/26 and 10/16. The CAISO net peak occurred on September 6th during the 5 pm PST hour.

FIGURE 5-39: CAISO NET AND GROSS LOAD ON A TYPICAL EARLY SPRING DAY

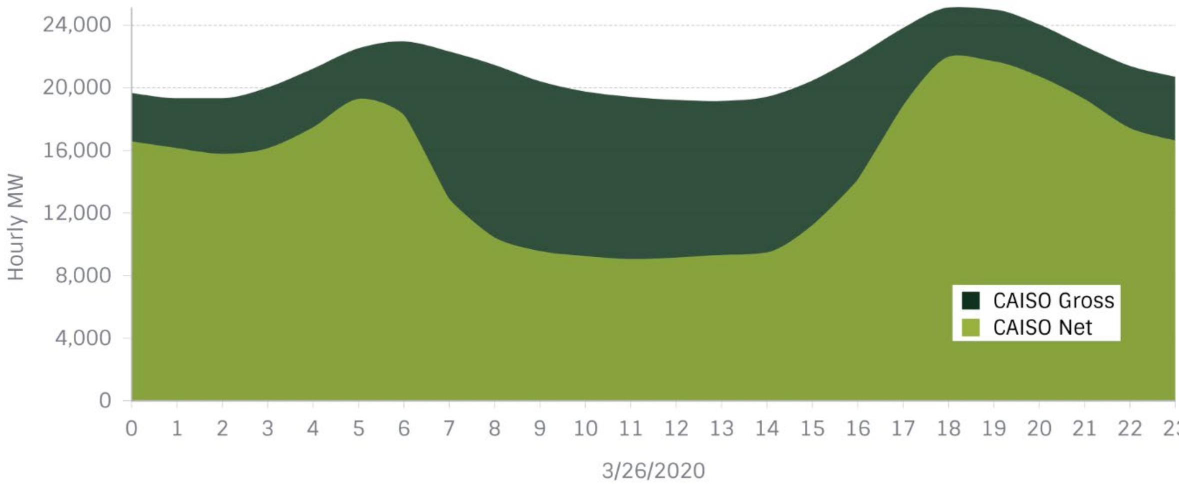


Figure 5-40 presents the CAISO net and gross load on August 18, 2020. During the 2 pm PST hour (3 pm PDT), CAISO gross load peaked. Longer days and more sunshine allow for more PV generation during daytime hours. However, as solar generation wanes in the late afternoon, demand is still building. As a result, the net peak occurs roughly three hours after the gross peak. The net peak on this day was the 6th highest in 2020. When examining other days within the summer, a similar pattern is revealed. The net peak can occur 1 to 3 hours after the gross peak.

FIGURE 5-40: CAISO NET AND GROSS LOAD ON 8/18/2020 (TOP GROSS HOUR OCCURRED DURING 2 PM PST)

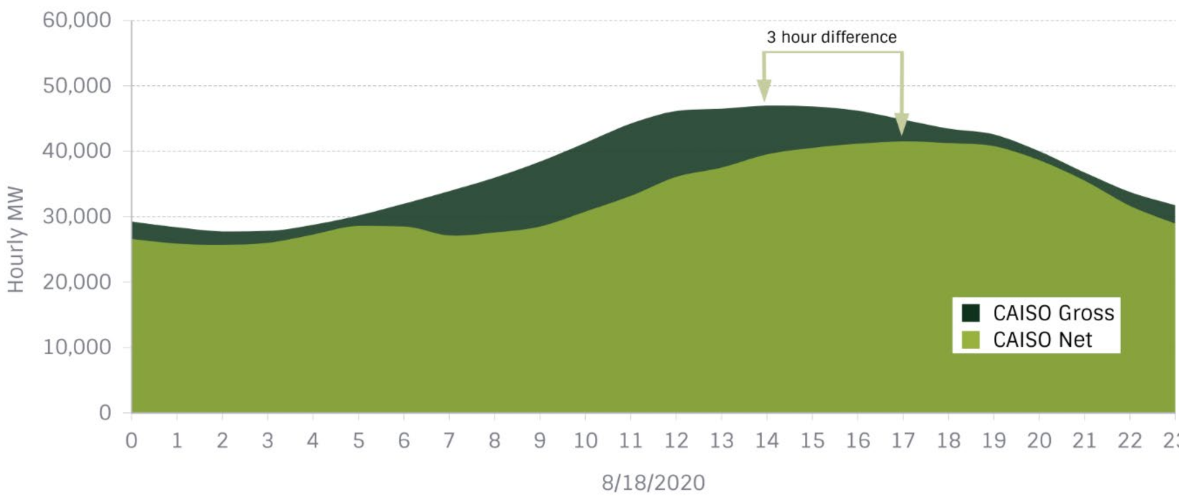


Figure 5-41 and Figure 5-42 below present the average kWh discharge per kWh capacity for nonresidential systems along with the gross and net peak MW for each of the top 200 CAISO hours, respectively. Both figures show nonresidential systems actively discharging, on average, throughout most gross and net peak hours. These peak hours generally occur in the summertime, however, the timing of when they occur helps explain why the magnitude of net discharge is different. The magnitude of net discharge throughout net peak hours is greater than the magnitude during gross peak hours. Net peak hours, on average, occur around 6 pm PST, while gross peak hours, on average, occur around 4 pm PST. Nonresidential storage systems, on average, are discharging a greater percentage of energy during the 6 – 8 pm PST hours, which aligns more with the net peak hours.

FIGURE 5-41: HOURLY NET DISCHARGE KWH PER KWH – CAISO TOP GROSS 200 HOURS FOR NONRESIDENTIAL

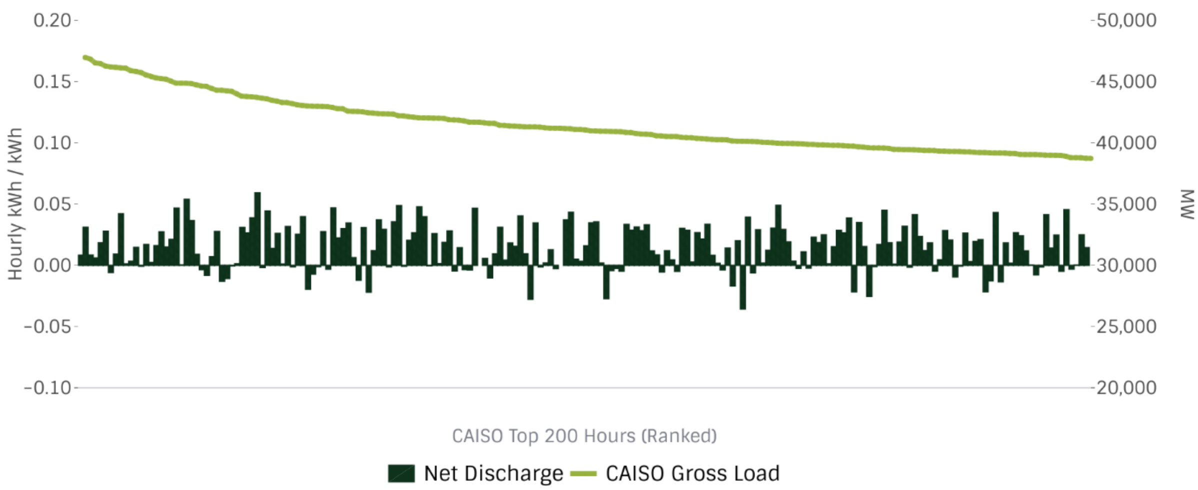


FIGURE 5-42: HOURLY NET DISCHARGE KWH PER KWH – CAISO TOP NET 200 HOURS FOR NONRESIDENTIAL

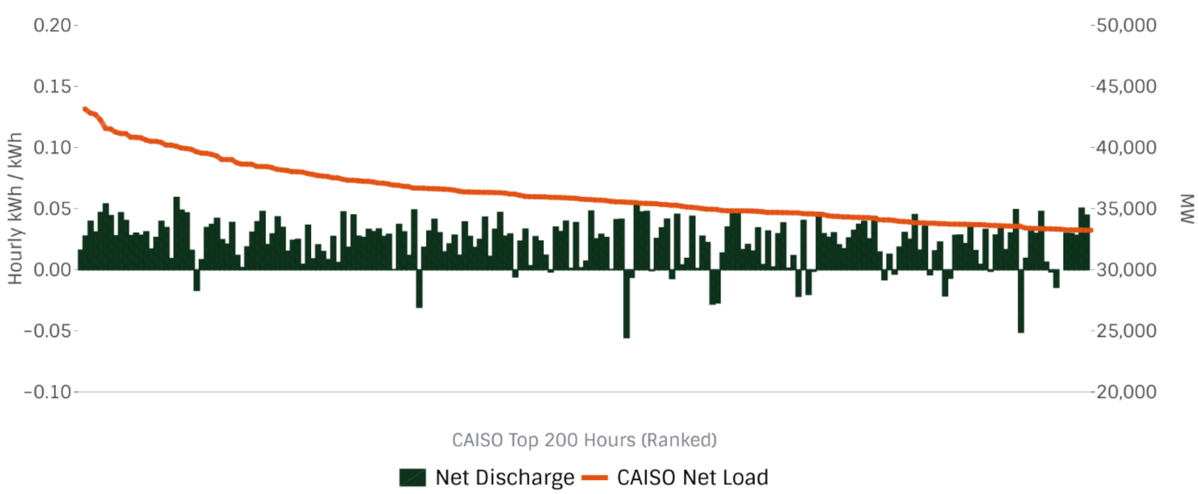


Figure 5-43 and Figure 5-44 below present the average kWh discharge per kWh capacity for residential systems along with the gross and net peak MW for each of the top 200 CAISO hours, respectively. Both figures show residential systems actively discharging throughout all but a few gross and net peak hours.

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For many of the top gross peak hours, residential systems, on average, are discharging greater than 10% of available capacity throughout those hours. There are far fewer observances like this during net peak hours. As mentioned previously, gross peak hours tend to occur earlier in the day than top net peak hours. Some of those earlier hours correspond to periods when residential systems are charging from paired PV, which is evident in the net charging throughout a few dozen top gross hours. Net peak hours generally occur when grid level renewables and on-site PV generation begins to lessen. We observe residential customers only charging from on-site PV, so there are far fewer net hours where residential systems are net charging.

FIGURE 5-43: HOURLY NET DISCHARGE KWH PER KWH – CAISO TOP GROSS 200 HOURS FOR RESIDENTIAL

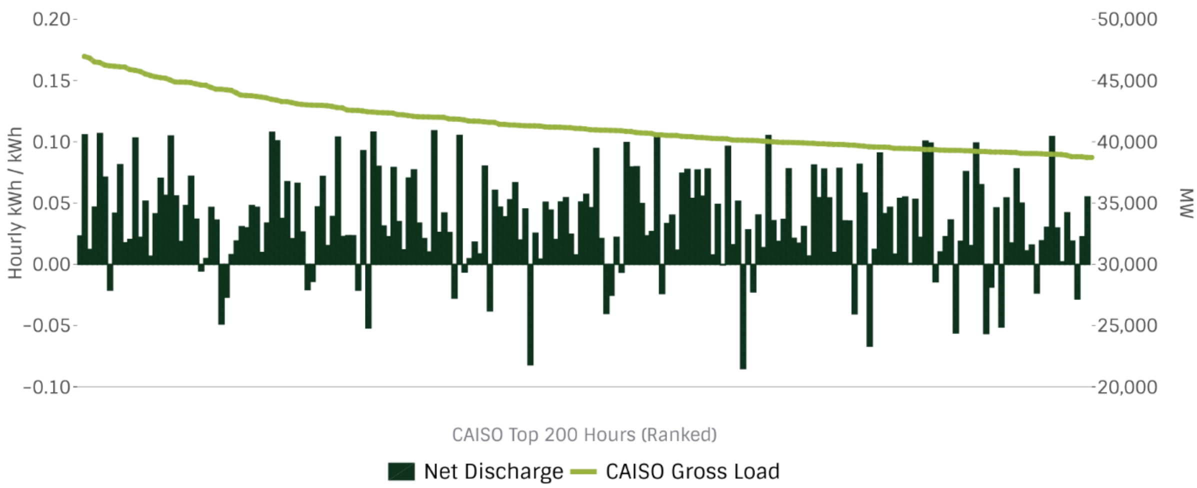
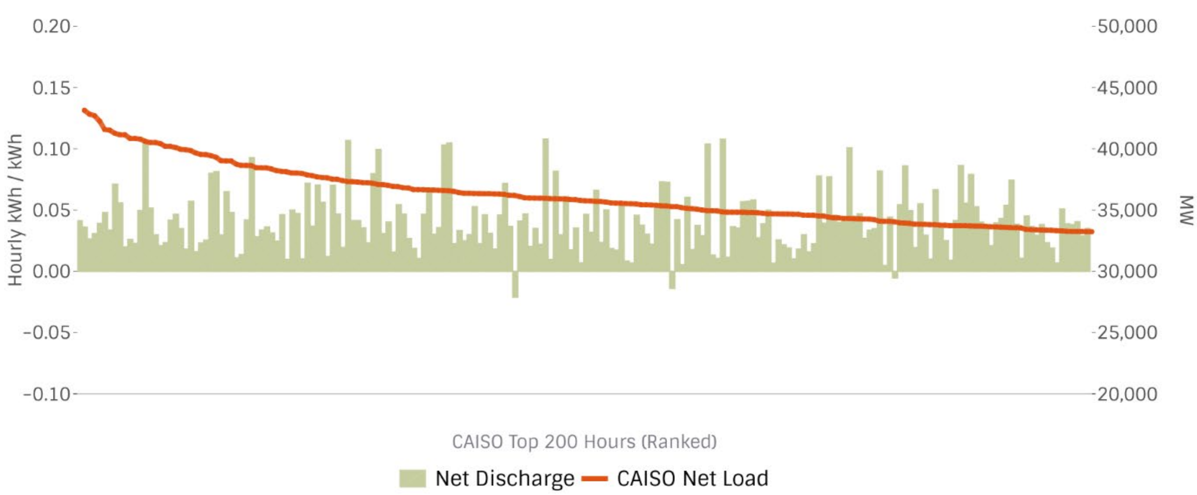


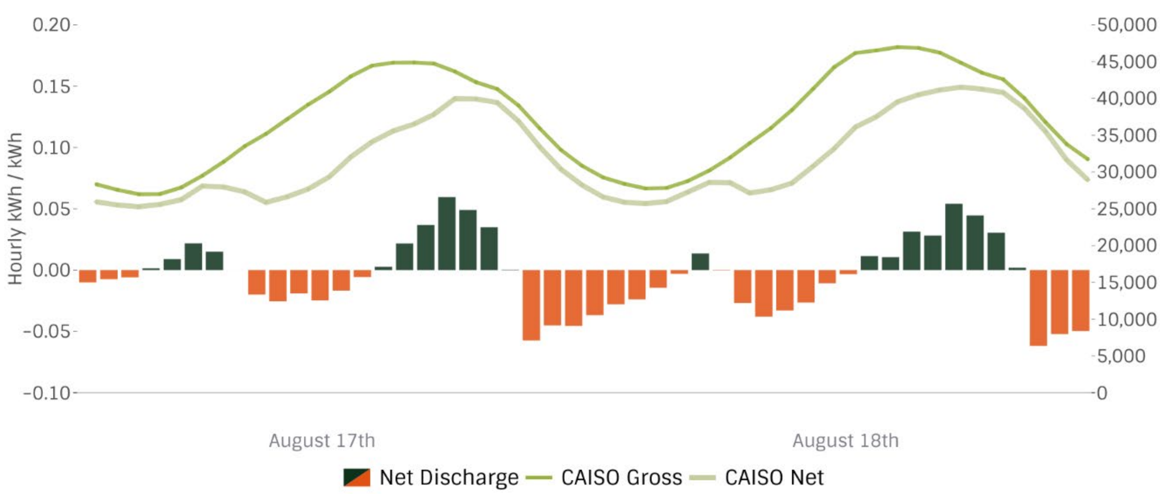
FIGURE 5-44: HOURLY NET DISCHARGE KWH PER KWH – CAISO TOP NET 200 HOURS FOR RESIDENTIAL



The variability in discharged energy capacity across different time periods and across customer sectors is predicated on the underlying load shapes and use cases for customers. 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 2020 – August 17th and August 18th. These data are presented below in Figure 5-45 and Figure 5-46. In both figures, the CAISO gross and net loads are provided along with the average hourly net discharge of storage for the nonresidential and residential sector, respectively. The belly of the "duck curve" is clear throughout the morning and early afternoon as renewables (namely solar) are generating. On August 18th the gross peak occurs around 2 pm PST, followed roughly three hours later by the net peak around 5 pm PST, when grid-scale renewables begin to wane in generation.

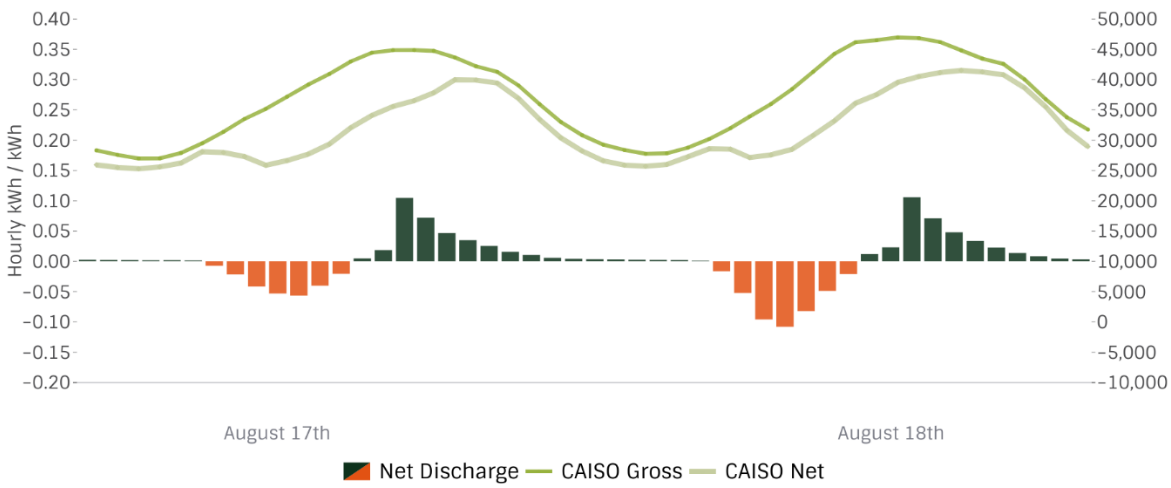
Nonresidential systems, on average, are discharging a greater percentage of capacity during the net peak hour and are generally charging throughout two distinct time periods. The first throughout morning hours as on-site PV begins to generate and storage systems paired with PV are absorbing excess generation. This period also aligns well with grid-scale renewables ramping up, which corresponds to the belly of the net CAISO load. Nonresidential systems are also charging during late evening hours, beginning around 9 pm PST. This period aligns with off- and super off-peak TOU periods. There is considerable variability in how nonresidential systems are being dispatched from a facility perspective. This is explored below in Figure 5-47.

FIGURE 5-45: NONRESIDENTIAL HOURLY NET DISCHARGE DURING PEAK CAISO DAYS



Residential systems exhibit a somewhat similar pattern of charging throughout morning on-site PV generating hours. However, we observe no charging during later evening hours like the nonresidential sector. Systems are generally discharging beginning around 3 pm PST which is coincident to peak CAISO gross hours. Discharging extends throughout the remainder of the afternoon and overnight, albeit at much lower magnitudes. Much like the nonresidential sector, there is variability in how residential systems are discharging and the magnitude of hourly discharge impacts. This was explored in Figure 5-20 and presented in more detail below in Figure 5-48.

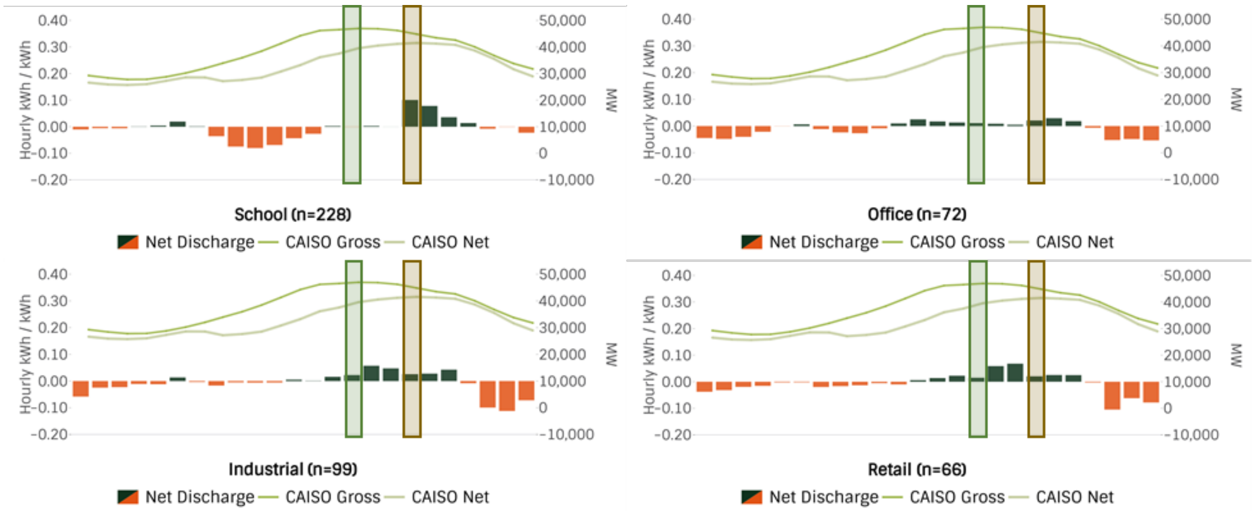
FIGURE 5-46: RESIDENTIAL HOURLY NET DISCHARGE DURING PEAK CAISO DAYS



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 found in previous evaluations. However, the magnitude of impacts during top hours continues to change 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.

Facility load shapes, demand requirements and presence of on-site generation equipment have a significant impact on how energy storage is dispatched to provide customer benefits. The magnitude and pattern of net discharge for different building types is presented below in Figure 5-47 for August 18th, 2020. The CAISO gross peak occurred during the 2pm PST hour on that day (highlighted in green in the figure) and the net peak occurred during the 5 pm PST hour (highlighted in brown). Again, discharging is positive, and charging is negative. The timing of discharge throughout the late afternoon and early evening for the facility types detailed below are different, along with their underlying load shapes and the impacts throughout those hours.

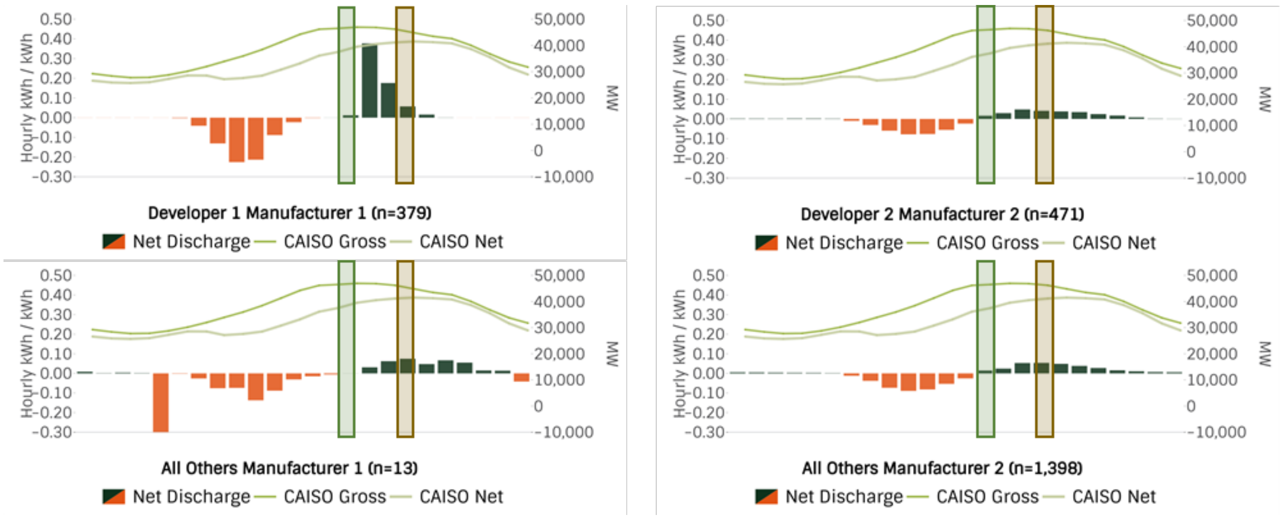
FIGURE 5-47: NONRESIDENTIAL HOURLY NET DISCHARGE DURING PEAK CAISO DAY BY FACILITY TYPE



As discussed in Section 5.3.1, we observe energy storage systems 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 5-47 presents how energy capacity is charged and discharged from residential systems that differ by manufacturer and developers. Developer 1 is the largest developer utilizing Battery 1 in 2020, and the "All Other" represents all other developers installing those systems. This is true for Developer 2 installing Battery 2 and "All Other" represents all other developing that same battery. As evident in the figure, Developer 1 Battery 1 is discharging a greater percentage of available capacity throughout two hours on August 18th – the 3 pm PST hour through the 4 pm PST hours – than the other developers and battery manufacturers. The most significant discharge occurs in the hours between the gross and net peaks on that day. A similar pattern of discharge is observed in the other three categories of developer/manufacturer – less magnitude of energy discharged throughout longer durations. These patterns suggest blended discharge behavior and multiple use cases – TOU arbitrage as well as self-consumption.

FIGURE 5-48: RESIDENTIAL HOURLY NET DISCHARGE DURING PEAK CAISO DAY BY DEVELOPER/MANUFACTURER



5.4 ENVIRONMENTAL IMPACTS

This section summarizes the environmental impacts associated with energy storage systems. We examine how the behavior of the systems led to an overall increase or decrease in greenhouse gas (GHG) emissions throughout 2020. The GHG considered in this analysis is CO_2, as this is the primary contributor to GHG emissions that is potentially affected by the operation of SGIP storage systems.[42]

Fifteen-minute 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 conditions. Baseline emissions are those that would have occurred in the absence of the storage system. Facility 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 facility loads and electrical supply in response to storage charging and discharging.

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. In other words, over the course of a year, these technologies will increase the energy consumption of a customer's home or facility relative to the baseline condition without the storage system.

42 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 15-minute energy impact of each system is equal to the charge or discharge that occurred during that interval. The energy impact during each 15-minute interval is then multiplied by the marginal emission rate for that interval (kilograms CO_2 / kWh) to arrive at a 15-minute emission impact. Emissions generally increase during storage charge and decrease during storage discharge. A system's annual GHG impact is the sum of the 15-minute emissions.

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. It is important to note that energy storage developers and customers are generally not aware of when marginal emissions rates are greater or less. The supply of energy, the sourcing of that energy, and marginal emissions associated with generation are generally not within their purview. However, Decision 19-08-001 required SGIP program administrators to provide project developers with a digitally accessible GHG signal based on day-ahead marginal emissions forecasts (in kilograms CO_2/kWh).[43] The purpose of the signal is to allow project developers an opportunity to better understand when marginal emissions are greatest throughout the year and to operate these behind-the-meter (BTM) resources in a manner that can co-optimize bill savings and emission reductions.

5.4.1 GHG by Upfront Payment Year

Figure 5-49 and Figure 5-50 present the range in GHG emission reductions (-) or increases (+) for the sample of nonresidential and residential projects analyzed as part of the 2020 impact evaluation. These boxplots are disaggregated by the year in which an SGIP energy storage project received their incentive payment. We observe an overall increase in system efficiency and utilization over time and this behavior helps contribute to many more realized GHG emission benefits in both customer sectors. Earlier generation nonresidential storage systems – those incented from 2014 to 2016 – exhibit higher average marginal emissions than systems receiving incentives more recently. Of the 66 nonresidential systems receiving incentives in 2016, the average increase in 2020 was 9 kg/kWh, with a median value of 8. The 234 systems receiving incentives in 2019 realized an average decrease in emissions of 6 kg/kWh capacity. Since 2018, when residential systems began receiving incentives, emission reductions have been substantial, averaging reductions of over 10 kg/kWh in 2020 for each incentive payment year.

[43] These data can also be found at https://sgipsignal.com/

FIGURE 5-49: EMISSIONS (KILOGRAMS GHG/KWH) FOR NONRESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR

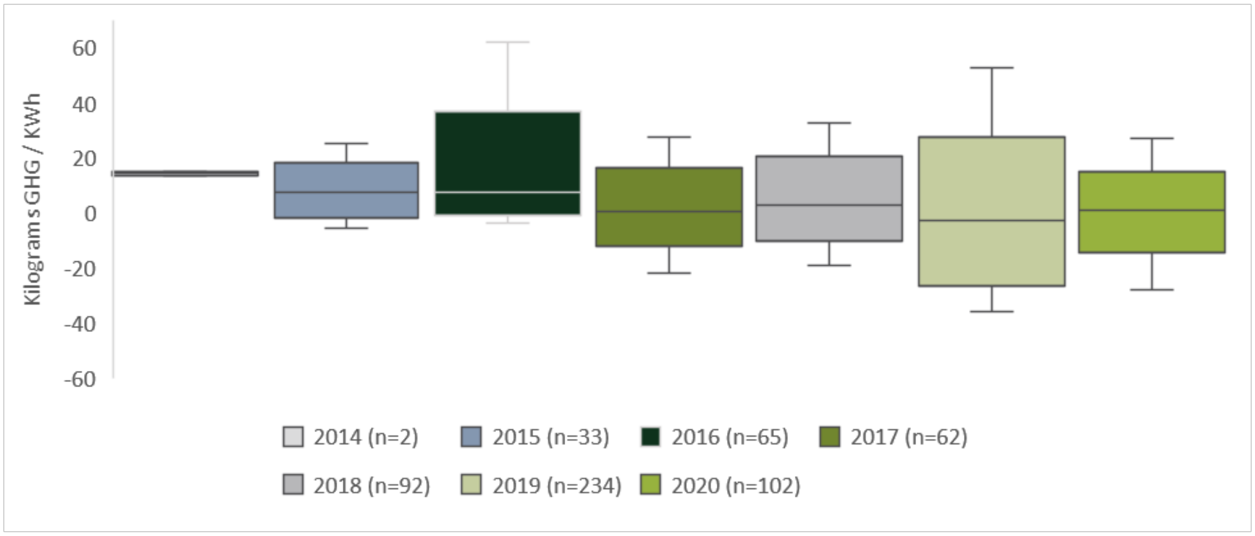
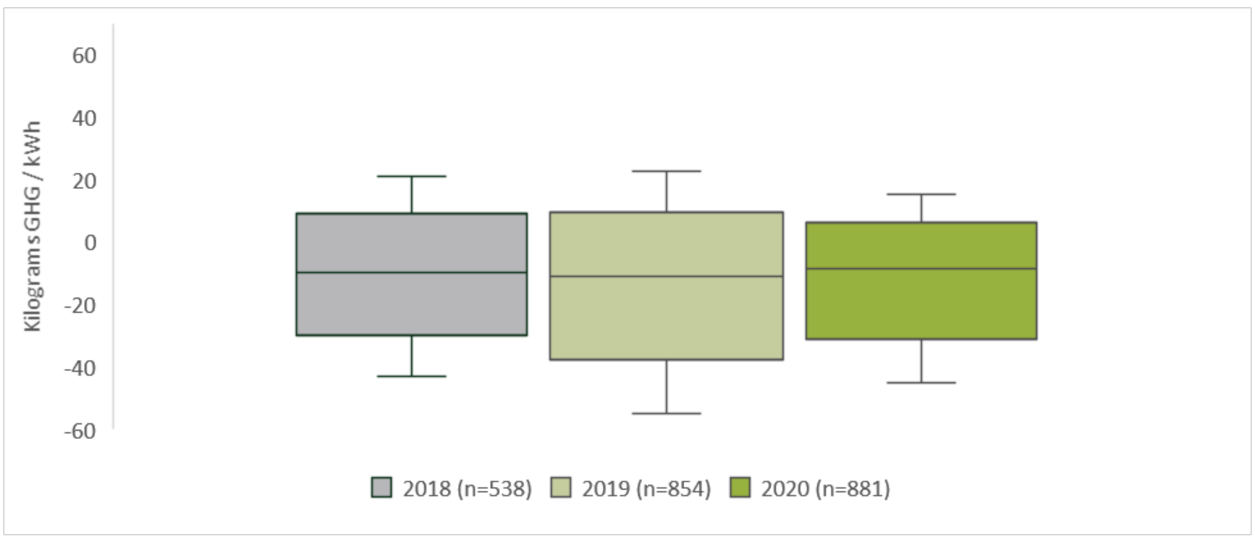


FIGURE 5-50: EMISSIONS (KILOGRAMS GHG/KWH) FOR RESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR



5.4.2 GHG Impacts by Legacy Status

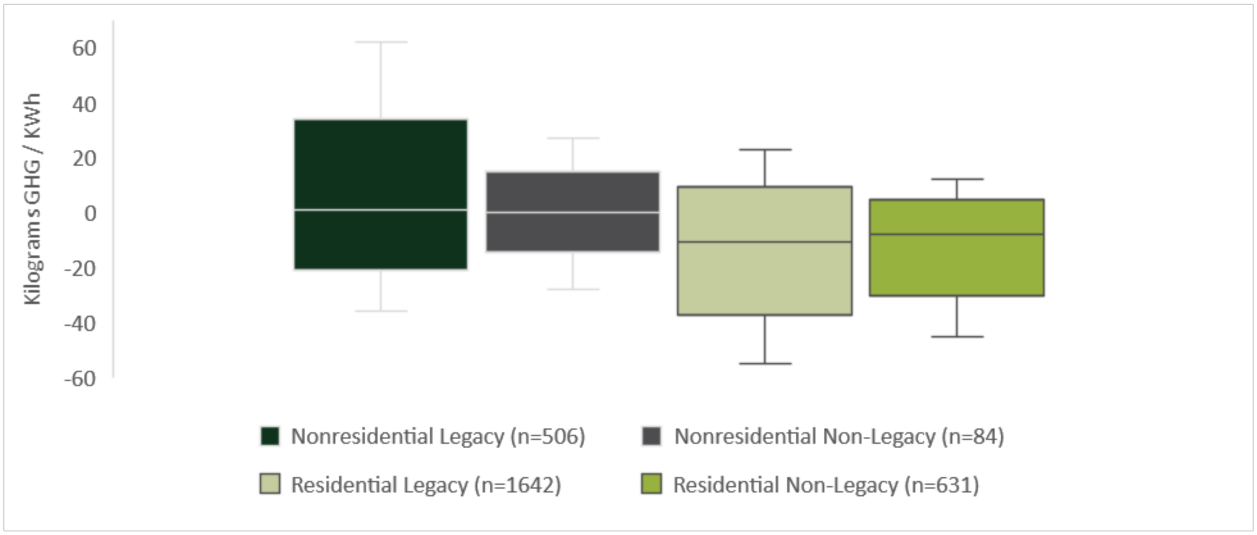
As discussed in Section 4, new provisions detailed in D. 19-08-001 regarding greenhouse gas (GHG) emissions provide developers and host customers with an opportunity to design and dispatch storage technologies in a manner that is beneficial from both a customer and a GHG emissions perspective. The decision also discusses compliance pathways and operational requirements for 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 are those submitting completed applications on or after 4/1/2020
  - Legacy projects are those submitting completed applications 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 receiving incentives on or after 4/1/2020 are also 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. There are currently no GHG emission enforcement mechanisms in place for residential projects, however 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.

Figure 5-51 presents the range in annual emissions for nonresidential and residential projects by legacy status. Legacy systems are all sampled projects that received upfront incentive payments prior to 4/1/2020 and new systems are those receiving payment any time on or after 4/1. As previously presented, we observe an average of almost 12 kg/kWh reduction in emissions from legacy residential projects, and a reduction of almost 10 kg/kWh for new projects. Both legacy and new nonresidential systems, on average, are increasing emissions, however slightly.

FIGURE 5-51: EMISSIONS (KILOGRAMS GHG/KWH) BY CUSTOMER SECTOR AND LEGACY STATUS



It's important to note that while new nonresidential projects are required to reduce emissions by at least 5 kg/kWh, Verdant could not develop annual impacts for these systems. New systems are classified as those receiving incentives on or after 4/1/2020 so we are unable to develop a full year of emission impacts for many of these projects. Some projects received incentives in October or November of 2020 and were not operational throughout the summer period when emission benefits can be best realized. There are 84 new nonresidential projects sampled as part of this evaluation and the range in emission increases/decreases is much tighter than for legacy systems.

Figure 5-52 conveys this, where the emission impacts for each nonresidential system is plotted against the utilization of the system throughout 2020. Legacy systems are colored lighter green and new systems are dark green. The size of the circles also provide context into the range in kWh capacities in the nonresidential sector. Most of the new projects are huddled around zero emissions, but most of them are also under-utilized from the perspective of annual cycles. This is because most new systems were not operational throughout the entirety of the year, having received their incentives at different times on or after 4/1. As discussed in Section 4, the sample design considers how partial-year impacts from projects incented throughout different periods in 2020 compares to projects that have a full year of impacts. When developing population-level GHG impacts for the program, our stratification of new versus legacy allows for the appropriate weighting from sample to population impacts.

FIGURE 5-52: KILOGRAMS GHG/KWH INCREASE (+) DECREASE (-) FOR NONRESIDENTIAL SYSTEMS BY LEGACY STATUS

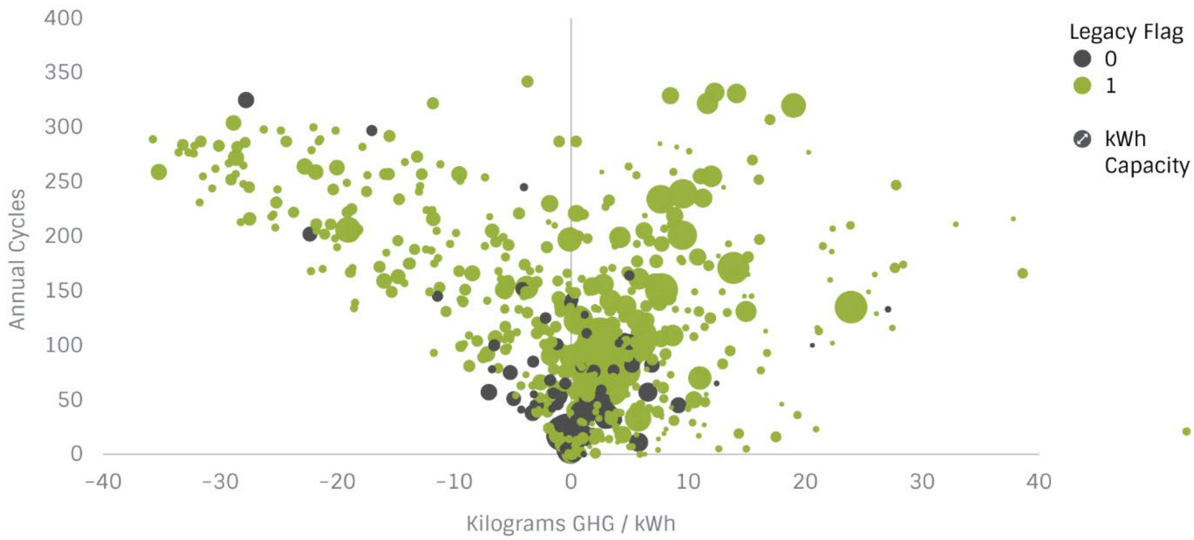
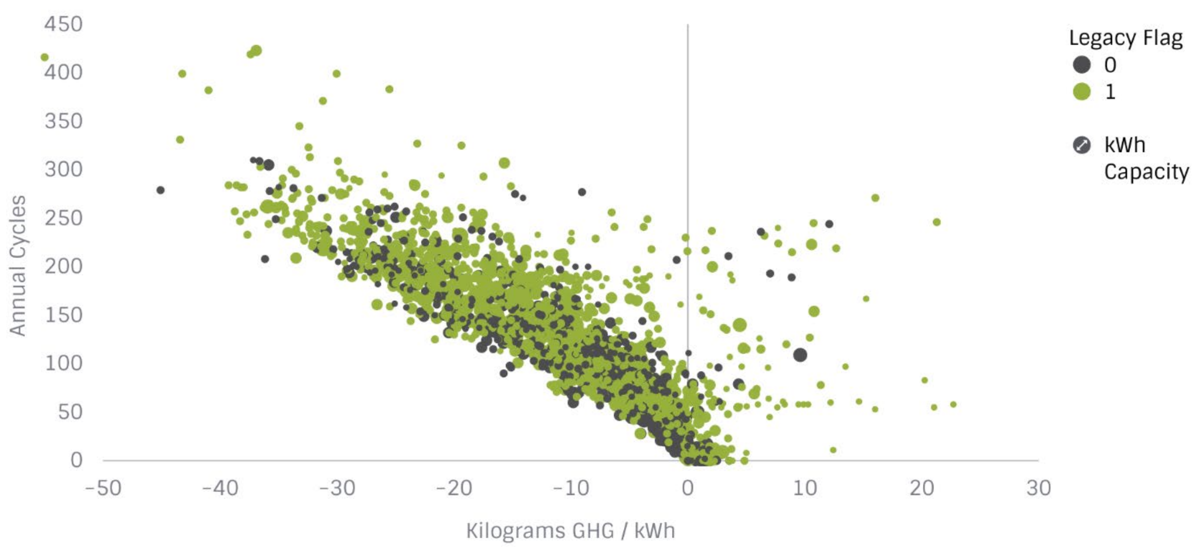


Figure 5-53 presents the individual project emissions per rebated capacity for the sample of residential customers. Over 90 percent of residential projects were reducing emissions in 2020 and there is a clear relationship between utilization and increased emission reductions. As evident in the boxplots presented previously, there is considerable range in the magnitude of impacts – from a 55 kg/kWh reduction to a 23 kg/kWh increase.

FIGURE 5-53: KILOGRAMS GHG/KWH INCREASE (+) DECREASE (-) FOR RESIDENTIAL SYSTEMS BY LEGACY STATUS



5.4.3 GHG Impacts by Facility Type and Systems Paired with On-Site PV

As discussed in Section 5.4, the capacity of 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 natural gas generators, marginal emissions tend to increase. We observed the pattern of storage charge and discharge with systems paired with on-site solar generation often aligns well with marginal emissions periods. Storage systems with PV are charging during early morning solar generating hours and discharging later in the day as solar generation wanes and customer loads ramp.

We captured these nuances in timing of charge and discharge as they relate to marginal emissions by examining the overall net emissions for nonresidential systems paired with on-site solar generation and systems which are standalone. As noted earlier, SGIP storage is installed in a variety of facility types where load shapes, demand requirements and operational nuances influence the size of the battery and dispatch behavior of those systems. We noted the installation of storage in a large fleet of primary and secondary schools, most of which were paired with on-site PV generation. Systems self-consuming excess PV generation to charge the storage system are doing so early in the morning when grid-level renewables are ramping up and marginal emissions are lower than late afternoon/early evening hours when the marginal generator is likely a natural gas power plant.

Figure 5-54 presents those findings. A combination of more utilization, charging from on-site solar PV and discharging throughout peak TOU periods which are coincident to higher marginal emission periods allows schools to realize GHG benefits that many standalone systems cannot.

FIGURE 5-54: KILOGRAMS GHG/KWH INCREASE (+) DECREASE (-) FOR NONRESIDENTIAL SYSTEMS BY BUILDING TYPE

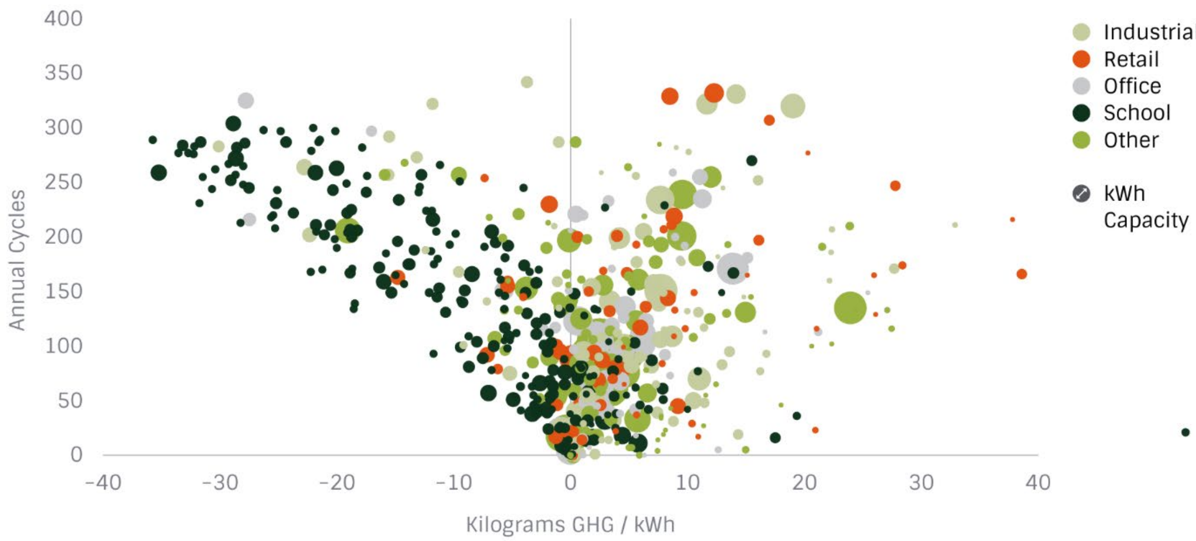


Figure 5-55 presents GHG emissions for each project and whether on-site PV generation is present at the facility. PV flags were generated based on whether a customer's load goes negative throughout the day – signaling export – or in many cases, where Verdant received PV generation data directly from the project developer. Of the 283 projects where we identify on-site PV, 68 percent reduced emissions in 2020. Of the 307 standalone projects, 16 percent reduced emissions in 2020.

FIGURE 5-55: KILOGRAMS GHG/KWH INCREASE (+) DECREASE (-) FOR NONRESIDENTIAL SYSTEMS WITH AND WITHOUT ON-SITE PV

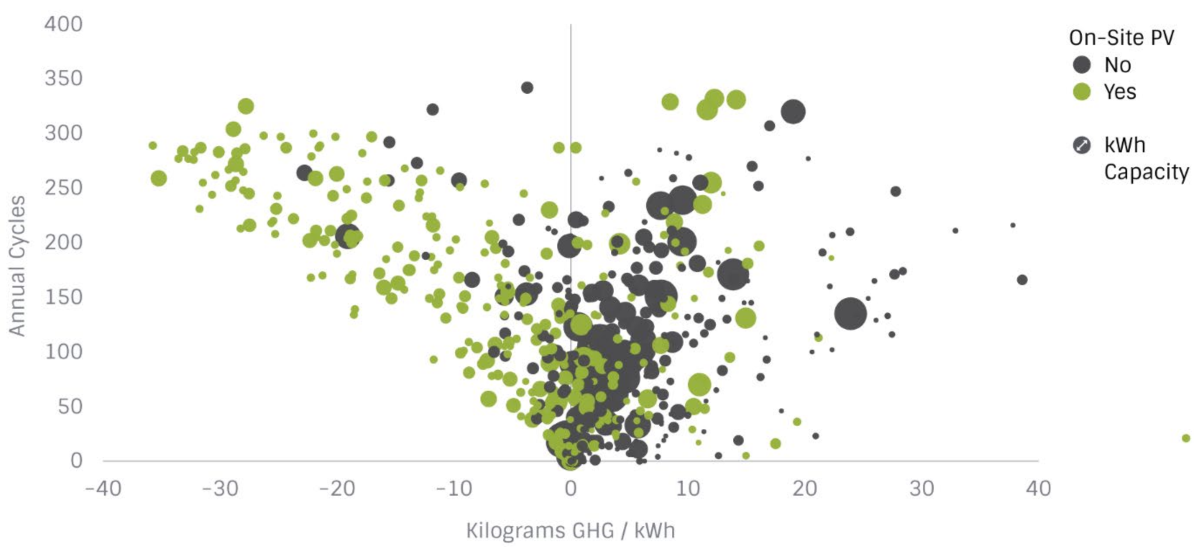
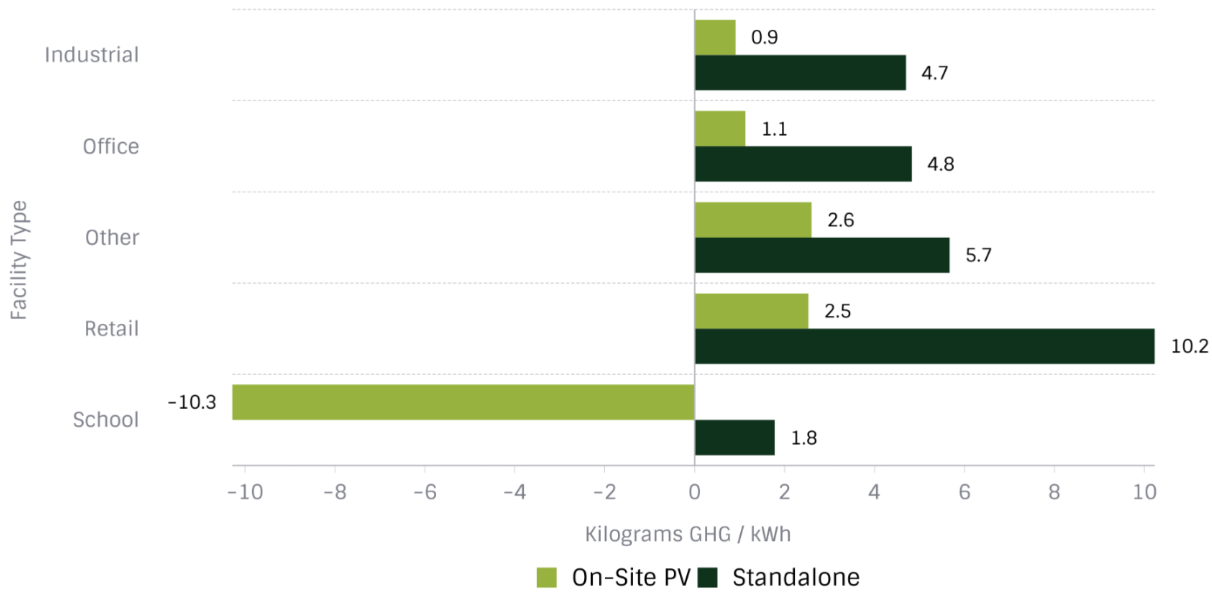


Figure 5-56 provides the average emission increase or decrease for each facility type and whether on-site PV was present. For the four building sectors with increases in emissions, those paired or co-located with on-site PV have much lesser increases than those with standalone storage systems. Storage installed in schools which are paired with on-site PV are reducing emissions by roughly 10.3 kg per kWh. Standalone storage systems installed at schools are increasing emissions by roughly 1.8 kg per kWh capacity.

FIGURE 5-56: KILOGRAMS GHG/KWH INCREASE (+) DECREASE (-) BY FACILITY TYPE AND ON-SITE PV



From a GHG perspective, the value of charging during 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 5-57 and Figure 5-58 display the average daily net discharge for residential systems – for the summer and winter periods[44] – along with the average marginal emissions shape, average net load and PV generation. In winter months marginal emissions are lowest during daylight hours when grid-scale renewables are generating and there is far less A/C load than summer months. In the summer, marginal emissions are highest during early morning and, most significantly, throughout a few early evening hours as renewable generation ebbs. As previously discussed, residential systems are charging in the morning from on-site PV generation and this time aligns well with lower marginal emissions. The peak magnitude

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

of discharge occurs late in the afternoon, but still during PV generating hours. It's important to note, residential TOU on-peak periods generally run from 4 pm to 9 pm. If storage systems waited to discharge until 6 or 7 pm, when marginal emissions are greatest, they could achieve even greater GHG reductions while maintaining the bill savings benefits. In winter, storage systems are utilized less often and at a lower magnitude.

FIGURE 5-57: RESIDENTIAL DISCHARGE KWH PER CAPACITY KWH AND MARGINAL EMISSIONS FOR WINTER

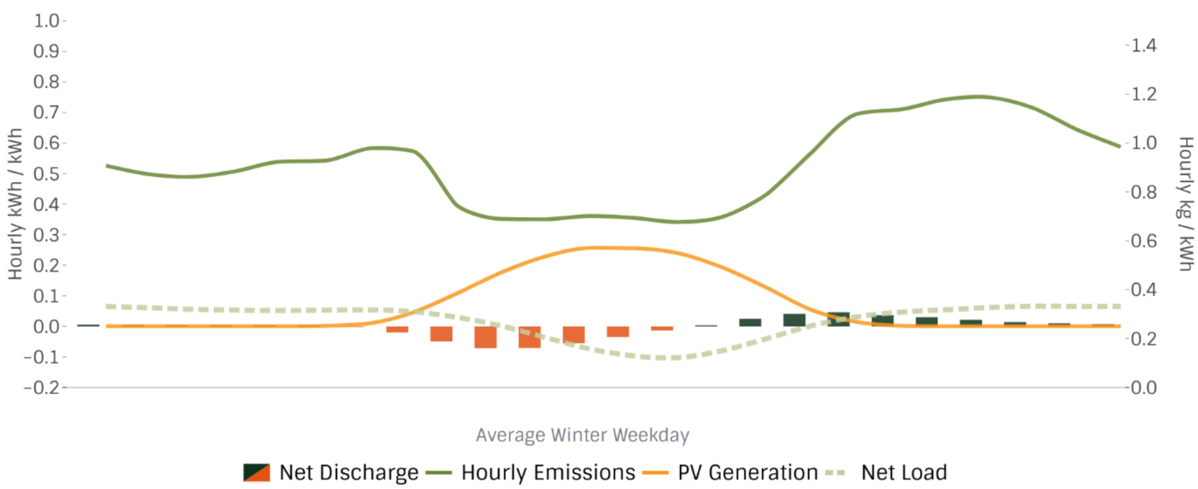


FIGURE 5-58: RESIDENTIAL DISCHARGE KWH PER CAPACITY KWH AND MARGINAL EMISSIONS FOR SUMMER

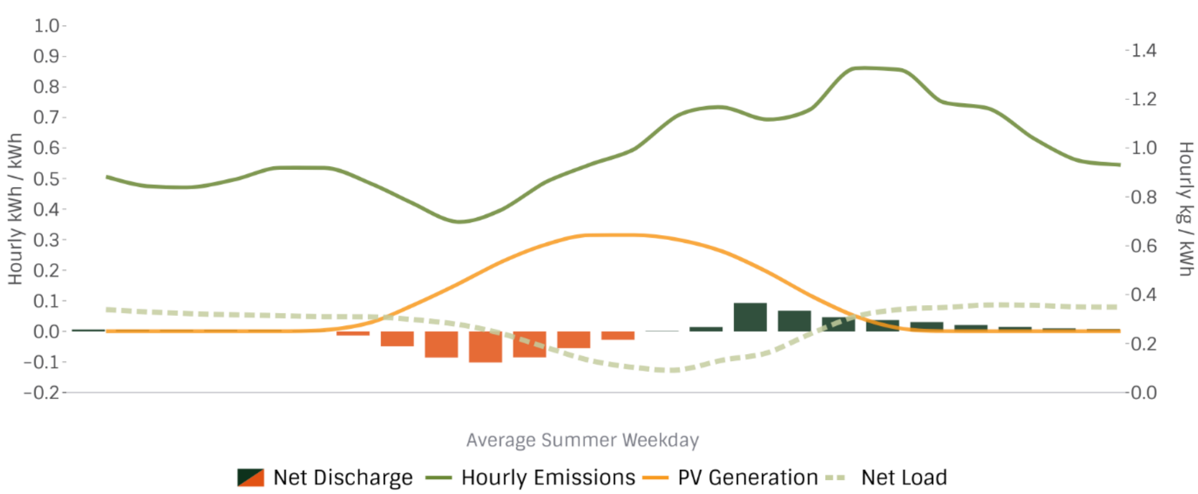


Figure 5-59 and Figure 5-60 display the average daily net discharge for nonresidential systems – for the summer and winter periods – along with the average marginal emissions shape, net load, and PV generation. Nonresidential systems, on average, are discharging throughout higher marginal emissions periods, but we observe charging after the on-peak period and overnight. These periods also represent high marginal emissions periods, so the GHG benefit accrued during on-peak is eroded by the net charging over the remainder of the day. Residential systems (and nonresidential systems paired with PV) are only charging in the morning hours which are coincident to PV generation ramping and lower GHG marginal emissions.

FIGURE 5-59: NONRESIDENTIAL DISCHARGE KWH PER CAPACITY KWH AND MARGINAL EMISSIONS FOR WINTER

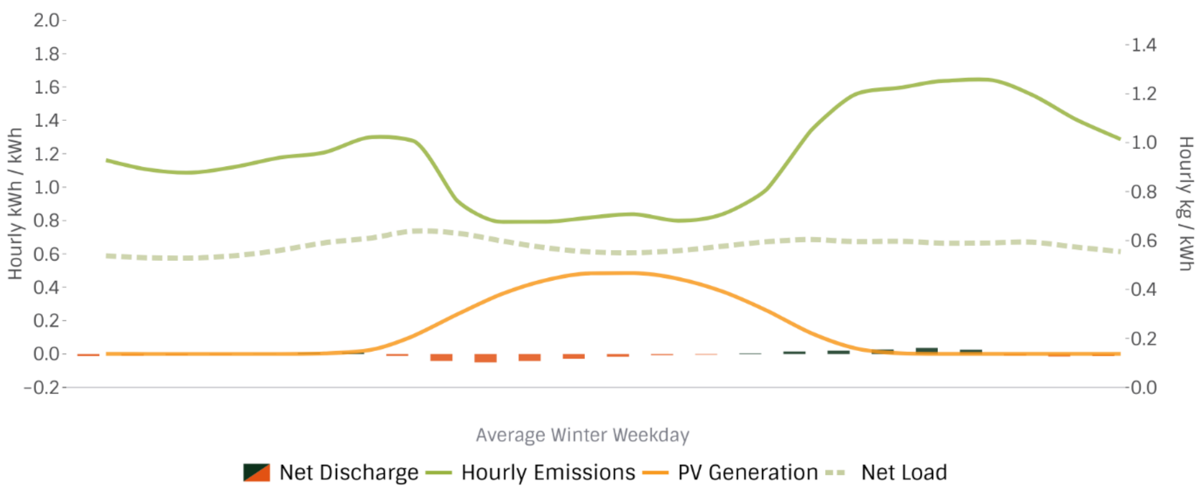
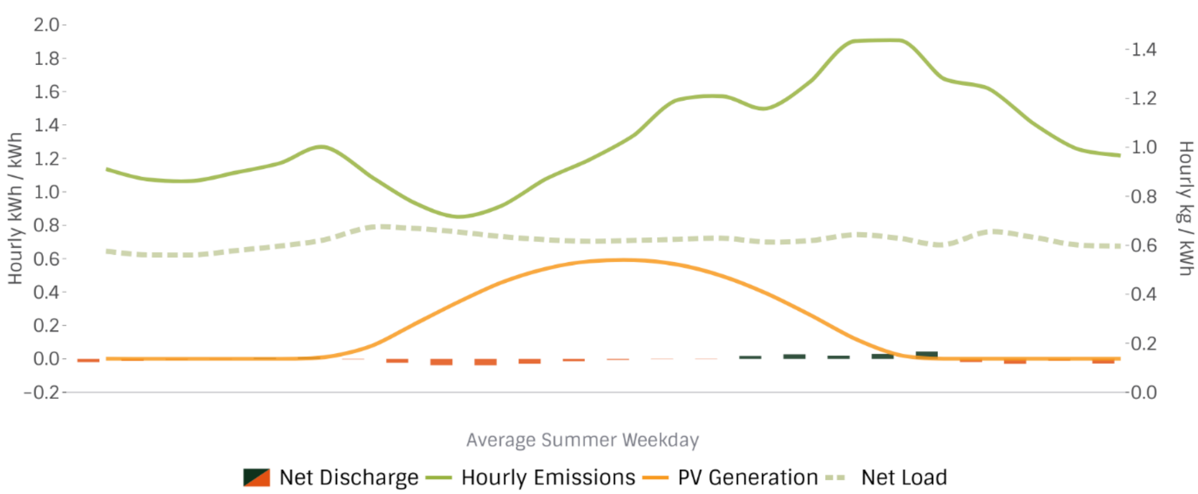


FIGURE 5-60: NONRESIDENTIAL DISCHARGE KWH PER CAPACITY KWH AND MARGINAL EMISSIONS FOR SUMMER



5.4.4 GHG Impact Summaries

Below we summarize the GHG impacts discussed above for both the nonresidential and residential sectors, respectively. Projects incented during 2020 are also presented differently depending on whether the project was legacy or non-legacy. All projects incented prior to 2020 are considered legacy since they received their upfront incentive payment prior to 4/1/2020. The nonresidential impacts are further disaggregated to represent whether systems were paired or co-located with on-site PV or not.

TABLE 5-3: SUMMARY OF NONRESIDENTIAL GHG IMPACTS

Upfront Payment Year	On-site PV	Legacy Project	Sample Project Count	Average Capacity (kWh)	Kg GHG / Capacity kWh
2014	Yes	Yes	2	272	14.0
	No		0		
	All		**2**	**272**	**14.0**
2015	Yes	Yes	6	1,133	7.7
	No		27	696	8.2
	All		**33**	**775**	**8.1**
2016	Yes	Yes	24	842	7.1
	No		41	719	10.7
	All		**65**	**765**	**9.2**
2017	Yes	Yes	24	1,001	0.1
	No		38	655	3.1
	All		**62**	**789**	**1.6**
2018	Yes	Yes	40	489	-1.7
	No		52	1,213	2.1
	All		**92**	**898**	**1.2**
2019	Yes	Yes	157	361	-10.8
	No		77	790	3.1
	All		**234**	**502**	**-3.6**
2020	Yes	Yes	6	590	-2.5
	No		12	1,488	2.8
	Yes	No	33	703	-2.7
	No		51	1,160	0.9
	All		**102**	**1,017**	**0.3**
Total	***Yes***		***292***	***529***	***-3.3***
	No		***298***	***920***	***3.5***
	All		***590***	***726***	***1.1***

TABLE 5-4: SUMMARY OF RESIDENTIAL GHG IMPACTS

Upfront Incentive Year	Legacy Project	Sample Project Count	Average Capacity (kWh)	Kg GHG / Capacity kWh
2018	Yes	538	16	-10.8
2019	Yes	854	17	-12.2
2020	Yes	250	18	-12.4
	No	631	19	-8.7
	All	881	19	-9.7
Total	***All***	***2,273***	***17***	**-10.9**

5.5 UTILITY MARGINAL COST IMPACTS

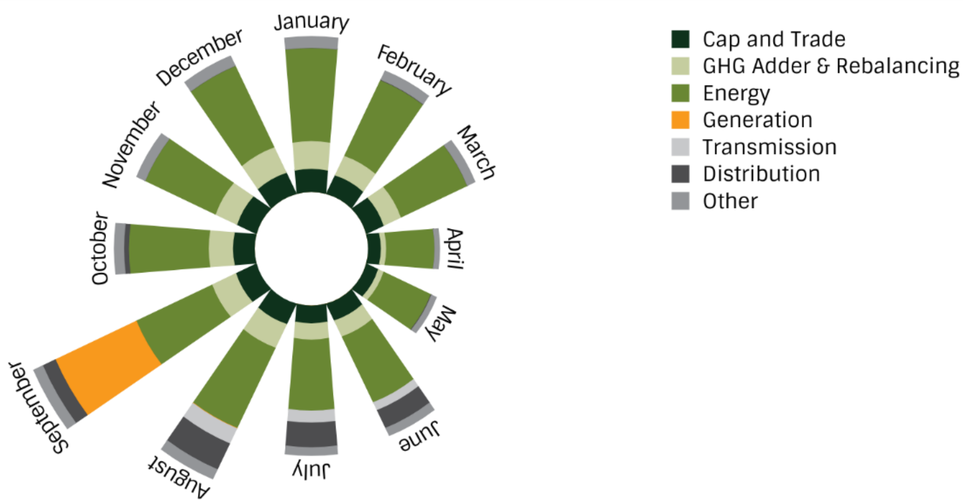
Utility marginal cost impacts were calculated for each IOU and each hourly time increment in 2020. This analysis was conducted using 2020 avoided costs from the CPUC-adopted 2021 avoided cost calculator. Storage system charging results in an increased load and therefore will generally increase cost to the utility. Discharging generally results in a benefit, or avoided cost, to the utility.

For energy storage systems to provide a benefit to the grid, 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. 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 the system. The avoided costs that were included in this analysis are:

- Cap and Trade
- GHG adder and Rebalancing
- Energy
- Generation Capacity
- Transmission Capacity
- Distribution Capacity
- Ancillary services
- Losses
- Methane leakage

Energy costs, GHG adder, and cap and trade costs represent the most consistent share of avoided costs throughout the year as evident in Figure 5-61.[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. These costs are allocated across the 15-minute time intervals of the year using a peak capacity allocation factor (PCAF) method.[46] This method assigns marginal capacity costs to each hour according to the interval's respective likelihood of being one in which additional generation capacity is needed.

FIGURE 5-61: 2021 AVOIDED COSTS BY MONTH AND COST CATEGORY



Source: 2021 Avoided Cost Calculator

5.5.1 Nonresidential Utility Avoided Costs

The normalized utility marginal costs are shown in Figure 5-62 by electric IOU for nonresidential energy storage systems.[47] Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). The

[45] In this exhibit, ancillary services, losses and methane leakage have been combined into an "Other".

[46] All hours with CAISO system load net of renewable generation below the threshold of one standard deviation of the peak load are assigned a capacity value of zero; those above this threshold are given weights in proportion to their proximity to the peak. The $/kW-year annual value is then allocated across these hours in proportion to the allocation factors.

[47] The levelized cost of ancillary services, losses and methane leakage have been combined into an "Other" category for presentation purposes.

timing, magnitude and duration of nonresidential storage charge and discharge behavior provided an avoided cost benefit to all utilities in 2020. The present evaluation found that, 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 the electric system load is peaking. Nonresidential systems were discharging throughout these highly constrained hours which is evident in the figure. Most savings were realized throughout a few generation-constrained hours which occurred in September of 2020. Overall, the average marginal *avoided* cost (+) for nonresidential systems in SCE territory is $5.00 per capacity (kWh), for PG&E they were $1.65 and for SDG&E they were $3.60 per capacity (kWh).

FIGURE 5-62: NONRESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY IOU

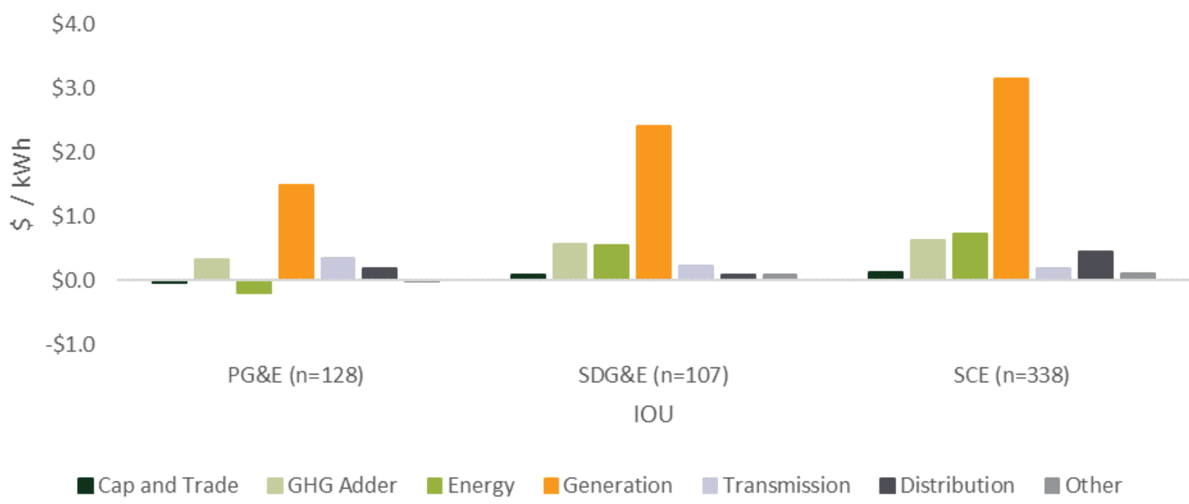
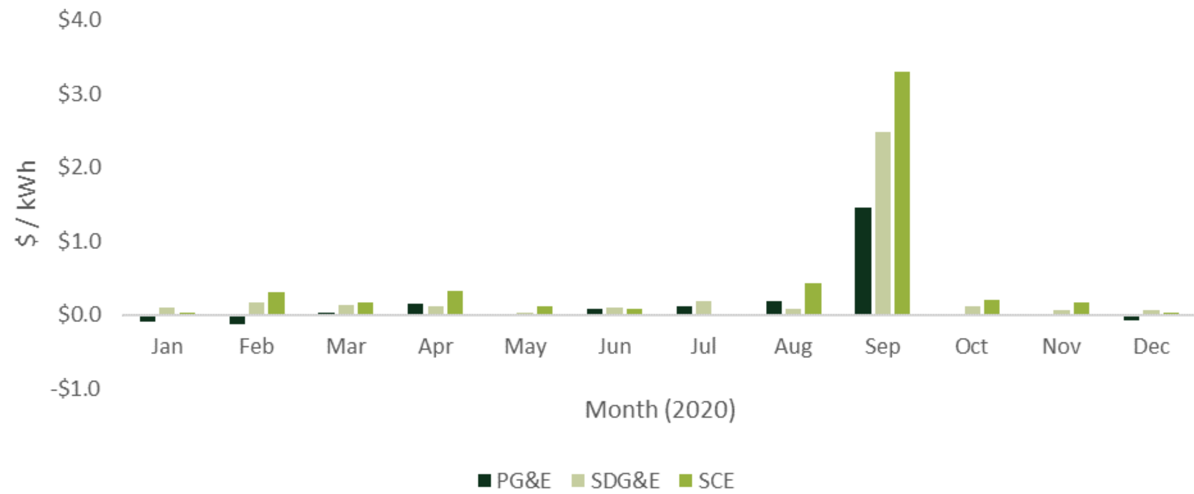


Figure 5-63 presents how those avoided cost benefits are allocated throughout 2020 for each IOU. Again, the marginal costs modeled in this study are highest when energy prices are high and the CAISO system load is peaking. Most of the system cost value is captured in a small number of high-cost hours 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.

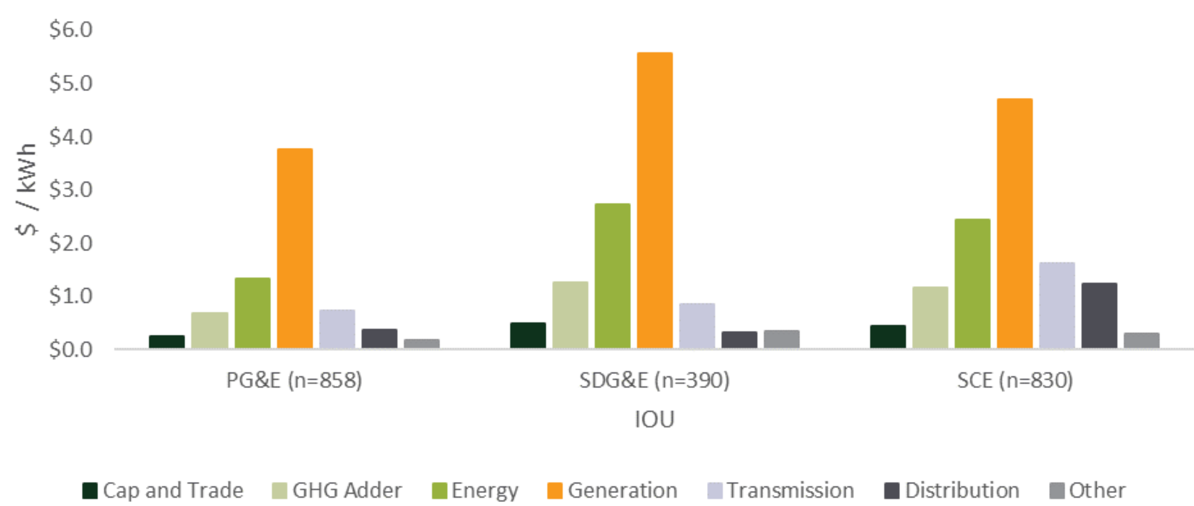
FIGURE 5-63: NONRESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY MONTH AND IOU



5.5.2 Residential Utility Avoided Costs

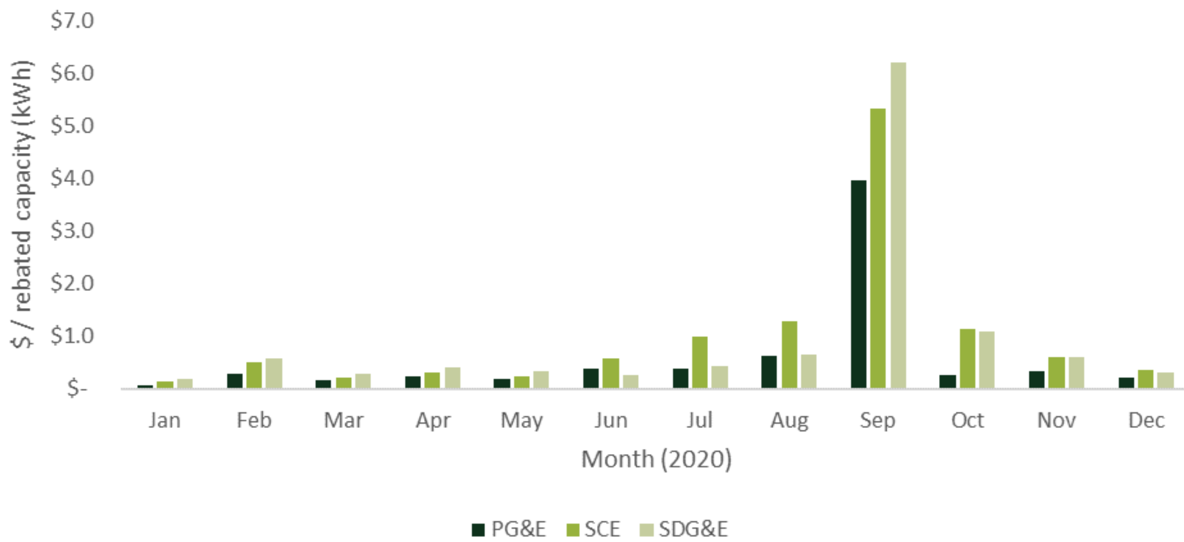
The normalized utility marginal costs are shown in Figure 5-64 for residential systems by electric IOU. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). Each of the three utilities realized total marginal cost savings throughout 2020 at a greater overall magnitude than nonresidential storage systems, when normalized by kWh capacity. Overall, the average marginal *avoided* cost (+) for residential systems in SCE territory is $11.70 per capacity (kWh), for PG&E they were $7.11 and for SDG&E they were $11.30 per capacity (kWh).

FIGURE 5-64: RESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY IOU



Residential storage behavior contributed to a net benefit to each of the three IOU systems. As discussed throughout this report, these systems were generally charging throughout low marginal cost periods and discharging in the early afternoon and evening during both high marginal cost and marginal emissions periods, especially throughout summer months. These higher costs also align with the new residential TOU periods and, as presented below in Figure 5-65, occur throughout the entirety of the year, but like nonresidential systems, the benefits accrued over a few generation-constrained hours in September.

FIGURE 5-65: RESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY MONTH AND IOU



5.5.3 Utility Avoided Cost Summaries

Below we summarize the total avoided cost benefits (+), or cost incurred (-) throughout 2020 for each of the three IOUs and two customer sectors – nonresidential and residential. We've also differentiated whether projects are considered legacy or not. The utilization, timing and efficiency of storage charge and discharge throughout 2020 provided an avoided cost benefit to all three IOUs. Residential projects provided a greater benefit, on average, as a percentage of capacity kWh and there are some differences across utility as well. Again, the avoided costs are driven much more substantially throughout a few capacity constrained hours, while other components of the avoided costs are more evenly distributed throughout the year.

TABLE 5-5: SUMMARY OF NONRESIDENTIAL UTILITY AVOIDED COSTS

Upfront Payment Year	Legacy	Sample Project Count	Average Capacity (kWh)	Average Avoided Cost ($/ Capacity kWh)
PG&E	Yes	102	578	$1.54
	No	26	750	$2.49
	All	**128**	**613**	**$1.74**
SCE	Yes	285	831	$5.48
	No	53	1,132	$2.54
	All	**338**	**878**	**$5.02**
SDG&E	Yes	103	452	$3.83
	No	4	348	-$0.81
	All	**107**	**448**	**$3.66**
Total	***Yes***	***490***	***699***	***$4.31***
	No	***83***	***974***	***$2.36***
	All	***573***	***739***	***$4.03***

TABLE 5-6: SUMMARY OF RESIDENTIAL UTILITY AVOIDED COSTS

Upfront Payment Year	Legacy	Sample Project Count	Average Capacity (kWh)	Average Avoided Cost ($/ Capacity kWh)
PG&E	Yes	612	18	$7.41
	No	246	20	$6.41
	All	**858**	**18**	**$7.12**
SCE	Yes	609	16	$11.26
	No	221	18	$12.96
	All	**830**	**17**	**$11.71**
SDG&E	Yes	286	15	$12.15
	No	104	19	$9.17
	All	**390**	**16**	**$11.36**
Total	***Yes***	***1,507***	***17***	***$9.86***
	No	***571***	***19***	***$9.45***
	All	***2,078***	***17***	***$9.75***

5.6 STORAGE IMPACTS DURING PSPS EVENTS

Wildfire risk poses a unique 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. This policy of de-energization has significant public policy and public health ramifications, especially for vulnerable individuals and communities, and the essential services they rely upon.

As discussed in Section 2, in September of 2019 the CPUC issued D. 19-09-027 establishing an SGIP equity resiliency budget.[48] To help deal with critical needs resulting from wildfire risks in the state, D. 19-09-027 established a new equity resiliency budget set-aside for vulnerable households located in Tier 3 and Tier 2 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.

By December 31st of 2020, the SGIP had provided incentives to 14,991 energy storage systems, installed across multiple customer sectors. PG&E had 560 (21 percent) of their total 2,708 storage projects experience a PSPS event in 2020. SCE had 216 sites (4 percent) of their total 5,373 projects experiencing a PSPS event, and SDG&E observed 383 (13 percent) of their 2,885 projects experience PSPS events in 2020. Figure 5-66 displays the percentage of sites from each utility that experienced PSPS events during 2020.

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

FIGURE 5-66: PERCENTAGE OF SITES AFFECTED BY PSPS EVENTS BY IOU

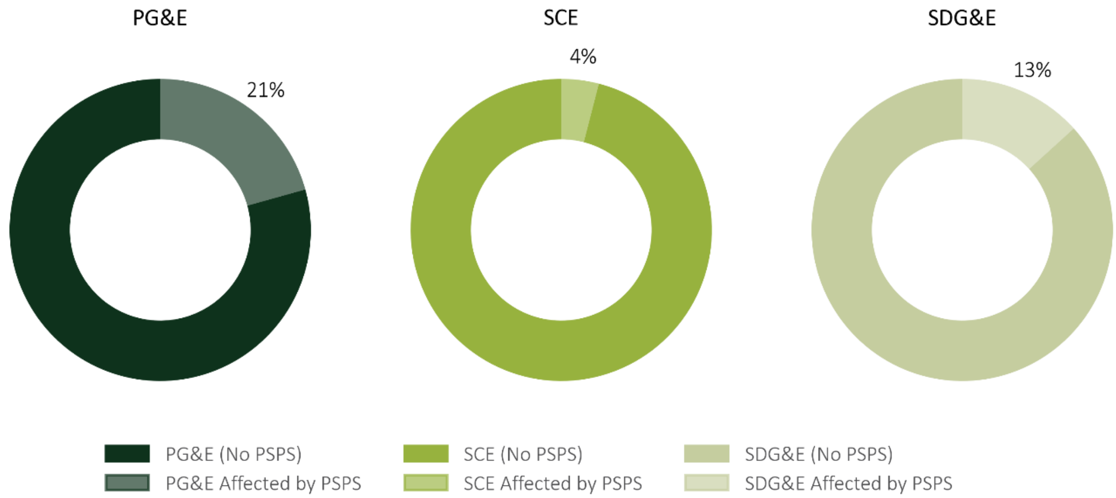
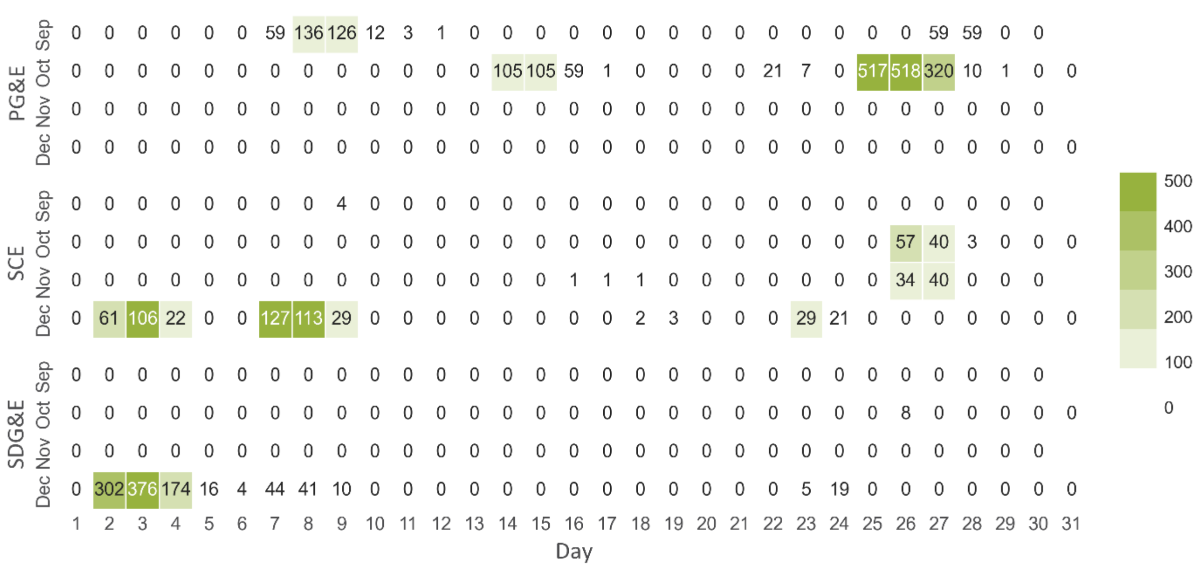


Figure 5-67 displays a heat map by IOU and month, highlighting the days with the largest number of projects affected by PSPS events. The data we received from each of the three IOUs showed PSPS events affecting a significant number of customers (over 50) during the following time periods:

- PG&E: September 7th – 9th, October 14th – 17th, and October 25th - 27th
- SCE: October 26th - 27th, December 2nd - 3rd, and December 7th - 8th
- SDG&E: December 2nd - 4th

FIGURE 5-67: PSPS EVENT DAYS BY IOU



The sample of data we analyzed includes almost 20 percent of the total of 1,159 sites experiencing PSPS events. The sample of PG&E sites analyzed below included 109 residential and 3 nonresidential sites, SCE includes 45 residential and 6 nonresidential sites, and SDG&E has 75 residential and 5 nonresidential sites. SGIP customers in PG&E territory experienced the longest PSPS outages, with the average length of outage being 35 hours (almost 1.5 days), and the longest event lasting 115 hours (almost 5 days during September). SCE saw their longest event lasting 53 hours (over 2 days in December), with the average event lasting almost 19 hours. SDG&E's average event lasted just over 1 day (28 hours) with their longest event lasting 59 hours (almost 2.5 days also during December).

The average and max energy storage discharge during a PSPS event is displayed below in Figure 5-68. The average discharge for each IOU ranges between 39% to 61% of a system's rebated kWh capacity over the course of a PSPS event. The max discharge ranged from 187% to 235% of a system's rebated kWh capacity, indicating that a system may discharge fully more than once over the course of a PSPS event.

FIGURE 5-68: AVERAGE DISCHARGE OVER A PSPS EVENT

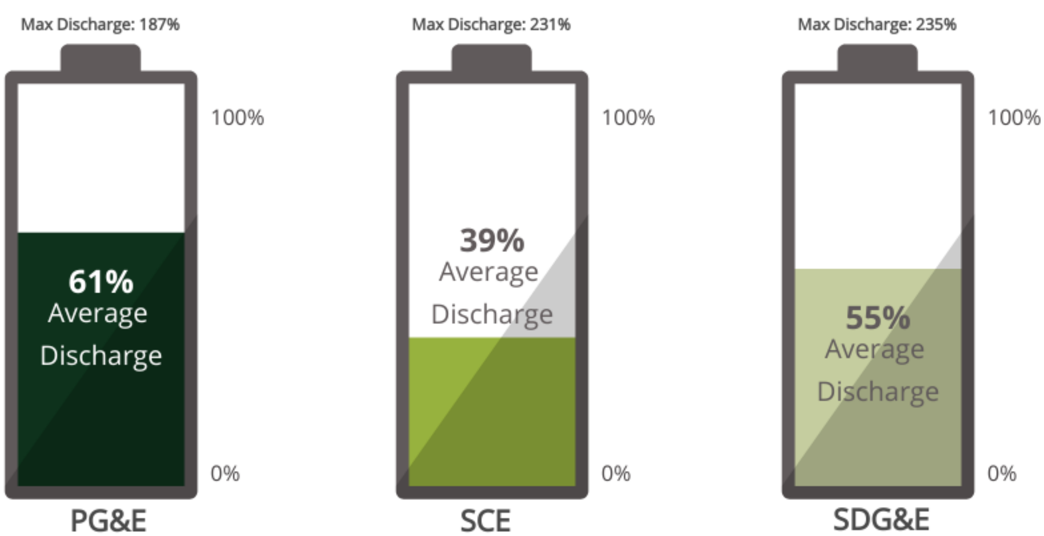
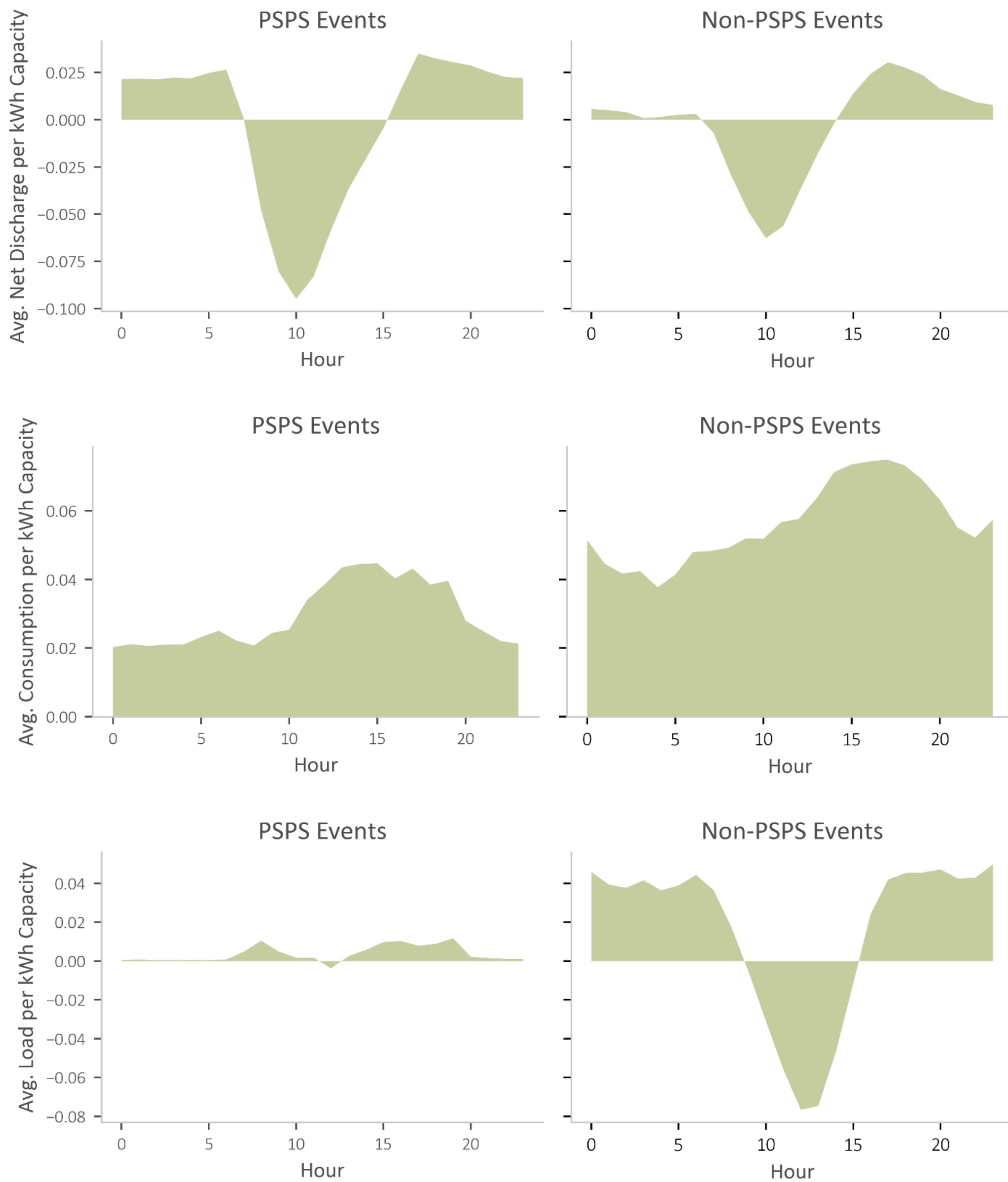


Figure 5-69 below displays the average hourly net discharge, consumption, and load (per kWh capacity of storage) for PG&E events in October. The graphics compare PSPS events to non-PSPS events over weekdays. Average consumption (middle graph) is significantly less (about a third) during PSPS events than it is during non-PSPS events, indicating that customers are actively trying to reduce their load during these events. The average load also reduces to just about zero during these events, as expected.[49]

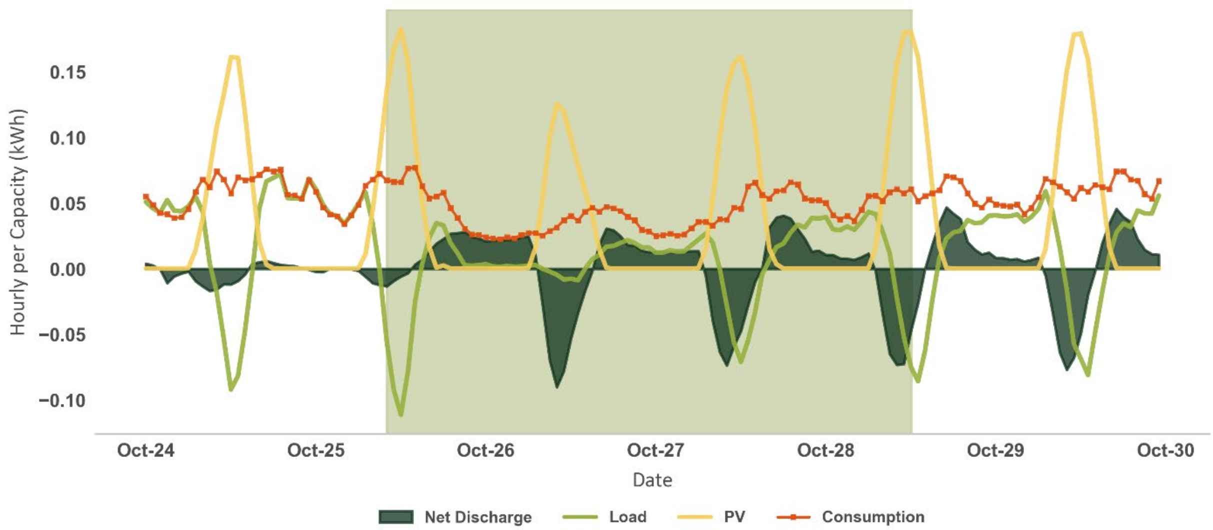
[49] The load isn't quite zero, because a customer may not experience a PSPS event during the entire hour.

FIGURE 5-69: AVERAGE HOURLY NET DISCHARGE, CONSUMPTION, AND LOAD DURING PSPS EVENTS VS NON-PSPS EVENTS



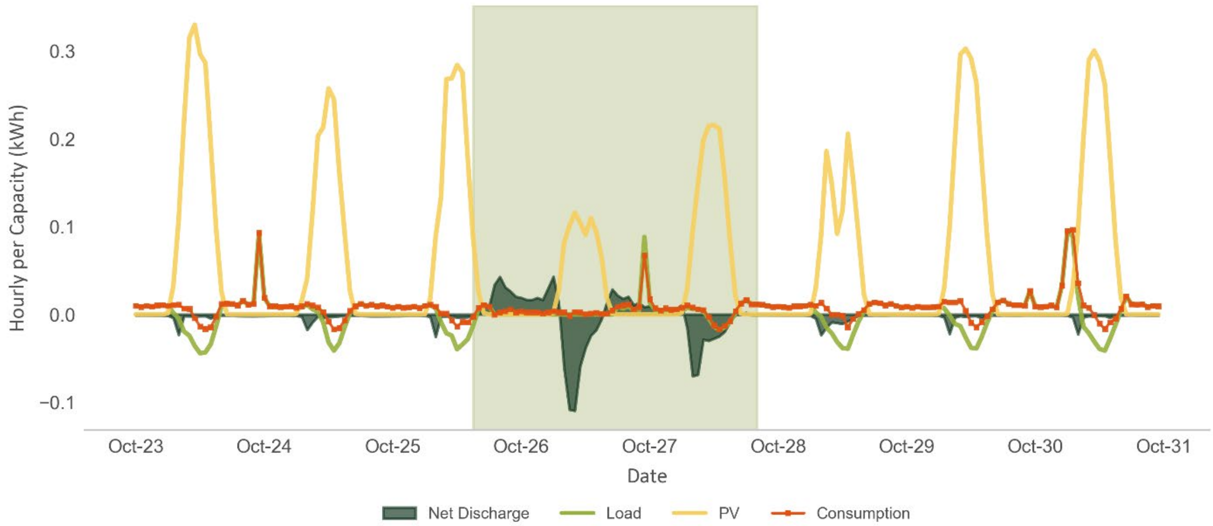
The net discharge, load, PV, and consumption for all PG&E customers who installed Battery 2 energy storage experiencing PSPS events during the last week of October are plotted below in Figure 5-70. The PSPS event period is highlighted in light green, over October 25th – October 28th. During this time, the average consumption (in orange) drops down, on average, to about a third or half of the normal consumption. The average load (light green) decreases significantly, while net discharge (dark green) shows a higher rate of discharge during these PSPS event days.

FIGURE 5-70: NET DISCHARGE, LOAD, PV, AND CONSUMPTION FOR PG&E BATTERY 2 SITES



Only customers installing Battery 2 systems were included in the analysis above. Developer 1/Battery 1 batteries installed in the PG&E territory display much different charging characteristics during winter months, as shown below in Figure 5-71. These systems are designed to only operate during peak periods, therefore in winter months the batteries are not discharging for TOU arbitrage. However, as shown below, the batteries do respond during PSPS events, shown from the 25th – 27th of the month.

FIGURE 5-71: PG&E DEVELOPER 1 MANUFACTURER 1 SITES DURING WINTER MONTHS – NET DISCHARGE SHAPES



5.7 POPULATION IMPACTS

The previous sections presented the analyses conducted to showcase the impacts of individual storage systems and samples of distinct customer segments – residential versus nonresidential and systems paired with solar PV versus standalone systems. These analyses were intended to highlight how SGIP storage systems were behaving in 2020 and how they were performing to meet program objectives. These analyses were all based on sampled systems from a larger population of SGIP storage systems. In this section, metered data from the sample of projects were used to estimate population total impacts for 2020.

Section 4 provides more detail into how each of these samples were developed, but they are summarized below in Table 5-7. Overall, our team evaluated 2,935 systems receiving upfront payments prior to December 31st of 2020 or 475 MWh of total program capacity. The sample represents 20 percent of the total population by project count and 71 percent of the total population capacity. Again, large nonresidential systems and residential systems represent the most significant percentage of the population – in terms of capacity – and have the greatest influence on overall SGIP population impacts.

TABLE 5-7: SAMPLE COMPOSITION OF 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	663	947	70%	436	471	92%
Residential	2,272	14,041	16%	39	201	20%
Total	**2,935**	**14,988**	**20%**	**475**	**672**	**71%**

Below we summarize the population estimates for several program impact metrics for each customer sector along with the program total. Population project counts[50] and relative precision levels are also reported in the tables and are based on a confidence level of 90 percent. The lower the relative precision, the more confident we are that the population estimate includes the true population value. Population estimates were calculated for the following in 2020:

- Electric energy – total energy charged, discharged and the overall roundtrip efficiency
- CAISO system peak demand – total CAISO top hour impacts and total top 200-hour impacts
- Environmental Impacts – total GHG impacts
- Utility Avoided Costs – total utility avoided costs

Total net discharge (i.e., the total energy impact that resulted from charging and discharging energy storage) during 2020 is summarized in Table 5-8. Electric energy impacts for all customer sectors are negative, reflecting increased energy consumption. As expected, storage systems inherently consume more energy than they discharge due to the combined effects of several factors, including standby loss rates, utilization levels and roundtrip efficiency. Nonresidential systems represent the most significant increase in total energy given their relative size. The total energy impact was an increase in electric energy consumption of 12,432 MWh during 2020.

[50] These population estimates exclude the impacts from three thermal storage systems and 530 residential systems. These represent projects that applied to the SGIP prior to 2016 and where data availability and integrity issues precluded an evaluation of these systems. However, these population impacts represent 99.3% of the energy capacity within the SGIP.

TABLE 5-8: ELECTRIC ENERGY IMPACTS

Customer Sector	N	Population Discharge (MWh)	Population Charge (MWh)	Population Net Discharge (MWh)	Population RTE	Relative Precision
Nonresidential	947	47,862	59,499	-11,637	80%	0%
Residential	13,511	4,901	5,697	-796	86%	1%
Total	**14,458**	**52,763**	**65,195**	**-12,432**	**81%**	**0%**

CAISO system peak demand impacts are summarized in Table 5-9 and Table 5-10 for the gross and net top hours, respectively. In 2020 the CAISO statewide system gross load peaked at over 47,000 MW on August 18th during the 2 pm PST hour. The CAISO peaked, from a net load perspective, on September 6th during the 5 pm PST hour. Both customer sectors provided a system benefit throughout those hours by net discharging a total of roughly 7,204 kWh throughout the gross peak hour and 10,234 kWh during the 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 in August and September of 2020. Many residential and nonresidential SGIP participants received their upfront payment or began normal operations after these dates in 2020.

TABLE 5-9: CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS PEAK HOUR)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential	890	3,389	10%
Residential	11,297	3,815	17%
Total	**12,187**	**7,204**	**11%**

TABLE 5-10: CAISO SYSTEM PEAK DEMAND IMPACTS (NET PEAK HOUR)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential	897	3,381	17%
Residential	11,553	6,853	8%
Total	**12,450**	**10,234**	**8%**

The total impacts across the top 200 gross and net CAISO hours are presented below in Table 5-11 and Table 5-12. The system count is greater across the top 200 hours because some systems began normal operations and received their upfront payment during top CAISO load hours that weren't the peak hour.

TABLE 5-11: CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 200 GROSS HOURS)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential	915	915,748	5%
Residential	11,901	1,281,343	6%
Total	**12,816**	**2,197,091**	**4%**

TABLE 5-12: CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 200 NET HOURS)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential	925	1,274,294	6%
Residential	12,103	1,564,883	7%
Total	**13,028**	**2,839,177**	**4%**

Greenhouse gas impacts during 2020 are summarized in Table 5-13. Greenhouse gas impacts for nonresidential systems is positive, reflecting increased emissions. The magnitude and the sign of greenhouse gas impacts are dependent on the timing of storage charge and discharge. The residential sector, however, contributed to a decrease in GHG emissions throughout 2020. 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 5.5). 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 11.0 kg/kWh and nonresidential systems increased emissions by roughly 1.3 kg/kWh. The magnitude of GHG emission reductions within the residential sector combined with lower GHG emissions within the nonresidential sector – compared to previous years – has contributed to an SGIP energy storage population becoming a net GHG reducer in 2020.

TABLE 5-13: GREENHOUSE GAS IMPACTS

Customer Sector	N	Population Impact (MT CO_2)	Capacity MWh	MT / Capacity MWh	Relative Precision
Nonresidential	947	610	471	1.3	17%
Residential	13,511	-2,157	195	-11.0	7%
Total	**14,458**	**-1,547**	**667**	**-2.3**	**12%**

Utility marginal cost impacts during 2020 are summarized in Table 5-14. The evaluation found both customer sectors provided a utility-level population benefit of over $2.9 million in avoided costs. These results are consistent with the analyses presented in Section 5.6. Nonresidential and residential systems were generally discharging during hours that were capacity or distribution constrained, especially during the summertime. On average, nonresidential systems provided a benefit in avoided cost of roughly $2/kWh and residential systems provided a benefit of $9/kWh.

TABLE 5-14: UTILITY MARGINAL COST IMPACTS

Customer Sector	N	Population Impact (Avoided Cost $)	Relative Precision
Nonresidential	947	$995,312	10%
Residential	13,511	$1,951,594	6%
Total	**14,458**	**$2,946,907**	**5%**

APPENDIX A BILL SAVINGS ANALYSIS

A.1 BILL SAVINGS ANALYSIS

The bill savings analysis done for the 2020 SGIP energy storage evaluation was performed by calculating the total annual bill using the net load from a given customer and comparing that to the annual bill of the same net load minus the storage dispatch. The net load used for this calculation consists of hourly kW and kWh inputs for one year. Each annual bill calculation is performed independently to assure both the correct rate and kWh baseline allowance is applied for each calculation.

Each annual bill is calculated by first summarizing the monthly kW and kWh by tier and 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 the following:

- Energy exported to the grid is reimbursed at the full retail rate
- The monthly billing cycles aligns with a calendar month
- No minimum bill is applied
- No California Climate Credit is applied
- No taxes are applied

Table A-1 and Table A-2 present the actual rate schedules used to develop bill impacts for residential and nonresidential SGIP participants in 2019, respectively. These are further disaggregated by IOU.

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

IOU	Rate Schedule	Sample Count	Percent (%)
PG&E	A-6	1	1%
	E-1	3	2%
	E-6	11	9%
	E-TOU-A	83	66%
	E-TOU-B	4	3%
	EM-TOU	2	2%
	EV-A	18	14%
	EV2-A	4	3%
	Subtotal	**126**	**100%**
SCE	D	101	13%
	D-CARE	6	1%
	TOU-D-A	322	43%
	TOU-D-B	52	7%
	TOU-D-PRIME	88	12%
	TOU-D-T	23	3%
	TOU-D_4_9	151	20%
	TOU-D_5_8	5	1%
	TOU-GS2-D	1	<1%
	Subtotal	**749**	**100%**
SDG&E	DR	23	32%
	DRLI	1	1%
	DRSES	18	25%
	EV-TOU-5	5	7%
	EV-TOU/EV-TOU-2	2	3%
	GDRSES	6	8%
	TOU-DR	7	10%
	TOU-DR1	11	15%
	Subtotal	**73**	**100%**
All	**Total**	**948**	

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

IOU	Rate Schedule	Sample Count	Percent (%)
PG&E	A-1X	1	1%
	A-6	6	5%
	A10-X	12	10%
	AG-4-C	1	1%
	AG-5-B	1	1%
	B-19	5	4%
	B-19_1v	1	1%
	B-20_1v	1	1%
	B-20_t	4	3%
	E-19	53	45%
	E-19_1v	6	5%
	E-20_1v	19	16%
	E-20_2v	6	5%
	EV2-A	2	2%
	Subtotal	**118**	**100%**
SCE	TOU-8-B	12	4%
	TOU-8-D	74	26%
	TOU-8-E	4	1%
	TOU-8-R	16	6%
	TOU-EV-9	1	0%
	TOU-EV-NR-8	2	1%
	TOU-GS2-B	4	1%
	TOU-GS2-D	13	5%
	TOU-GS2-E	7	2%
	TOU-GS2-R	49	17%
	TOU-GS3-B	10	3%
	TOU-GS3-D	44	15%
	TOU-GS3-E	8	3%
	TOU-GS3-R	41	14%
	TOU-PA3-D	2	1%
	Subtotal	**287**	**100%**
SDG&E	AL-TOU2_<500kW_2v	10	11%
	AL-TOU_<500kW_2v	53	56%
	DG-R_2v	1	1%
	GAL-TOU_<500kW_2v	25	27%

	GDG-R_2v	3	3%
	TOU-PA_2v	2	2%
	Subtotal	**94**	**100%**
All	***Total***	***499***	

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 2020 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 data provided by project developers and Energy Solutions
- Metered load and PV generation data from project developers
- 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, 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 energy storage 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 capacity and identification of existing metering equipment that can be used for impact evaluation purposes.

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. 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 2020. 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	IOU
SGIP reservation number	X	X	X	
Storage system size (kW, duration, kWh)	X		X	
Program year (PY) of application and upfront payment date	X			
Customer sector	X			
Storage system payment type (PBI vs. Non-PBI)	X	X		
Storage system incentive	X			
Project developer	X		X	
Battery Manufacturer	X		X	
15-minute charge and discharge data (kWh)		X	X	
15-minute customer load data (kWh)			X	X
Renewable on-site generation (kWh)			X	X
Treatment of daylight savings		X	X	X
Data period beginning or ending		X	X	X
Unit of measure (kW, kWh, W, Wh, etc)		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

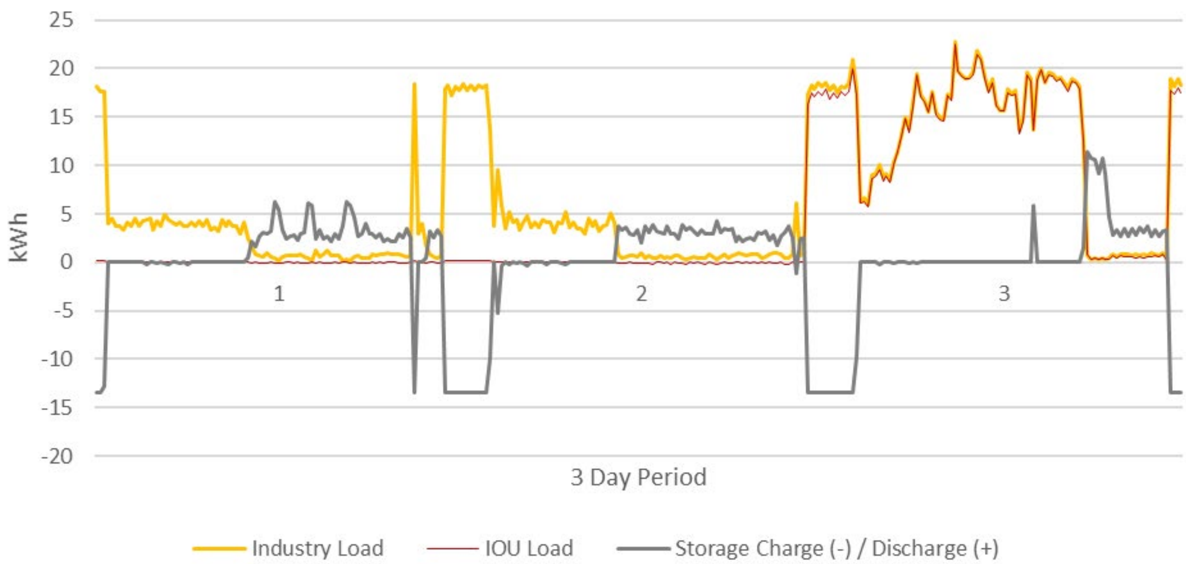
As discussed above, the storage analysis leveraged a variety of data sources including project developers, Energy Solutions (for projects that received a PBI incentive) and the electric utilities. We conducted an extensive data cleaning and quality control exercise to ascertain whether the data were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

- Interval battery 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 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).
- 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 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.

Figure B-2 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 are 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.

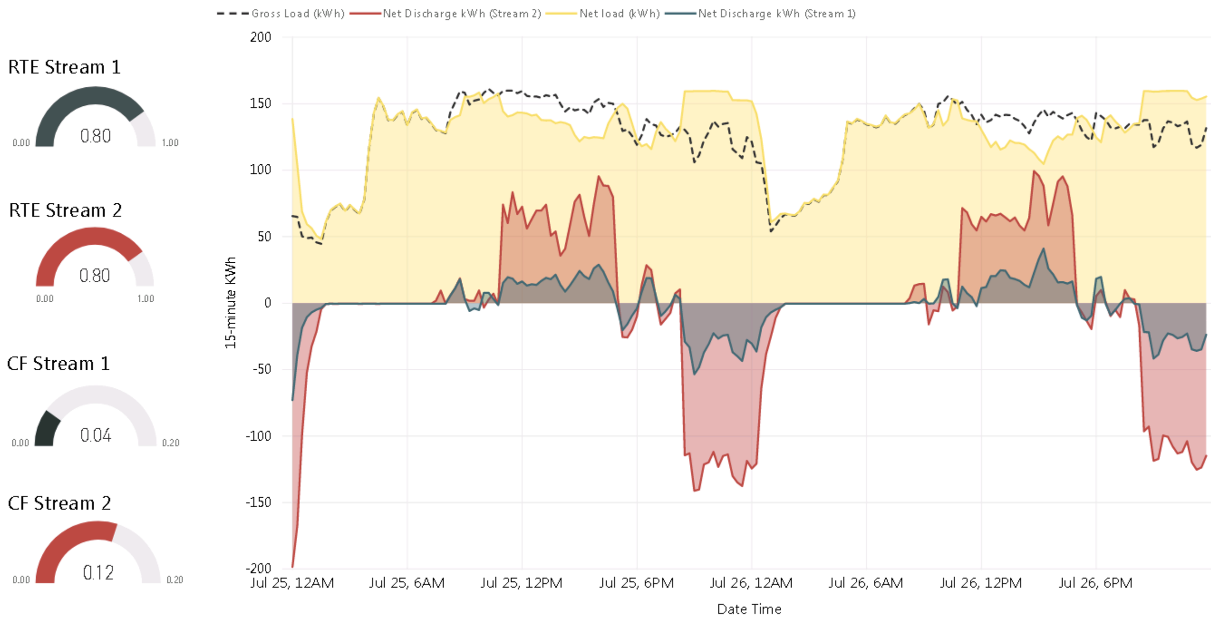
FIGURE B-1: EXAMPLE 1 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



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 were 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 5 discusses this performance metric in detail).

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-3 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



APPENDIX C ADDITIONAL FIGURES

This appendix contains additional figures that may be of interest but were not included in the main body of this evaluation report.

Net Discharge kWh per kWh Rebated Capacity during CAISO Top 200 Gross and Net hours (by Facility Type)

FIGURE C-1: NET DISCHARGE KWH FOR GROCERY STORES DURING CAISO GROSS PEAKS

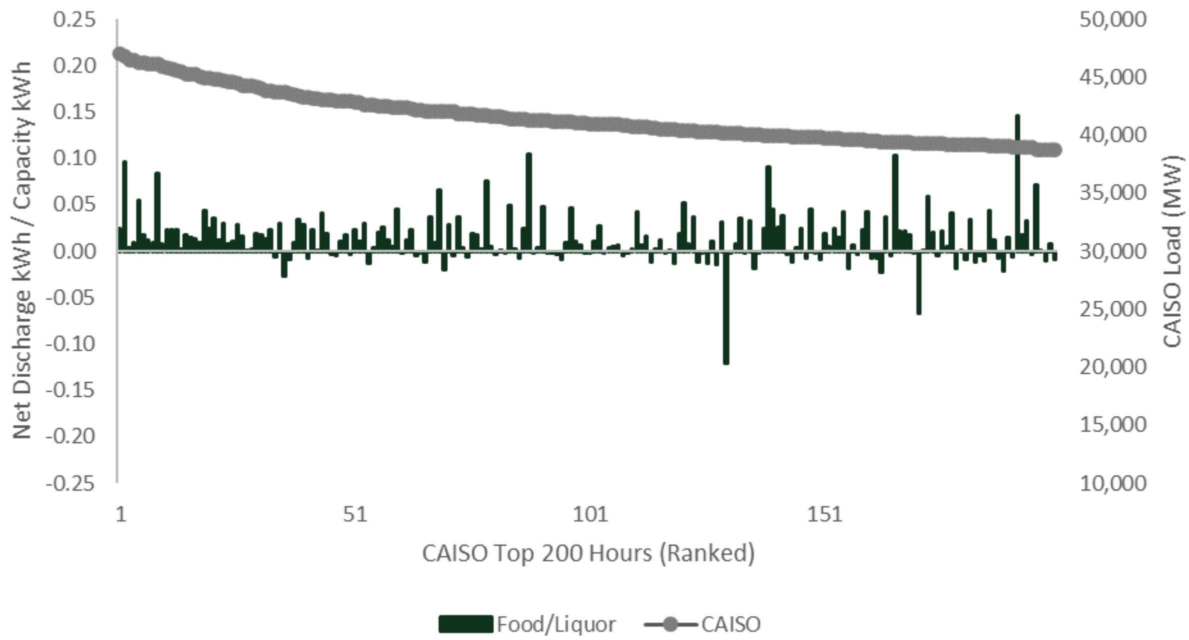


FIGURE C-2: NET DISCHARGE KWH FOR GROCERY STORES DURING CAISO NET PEAKS

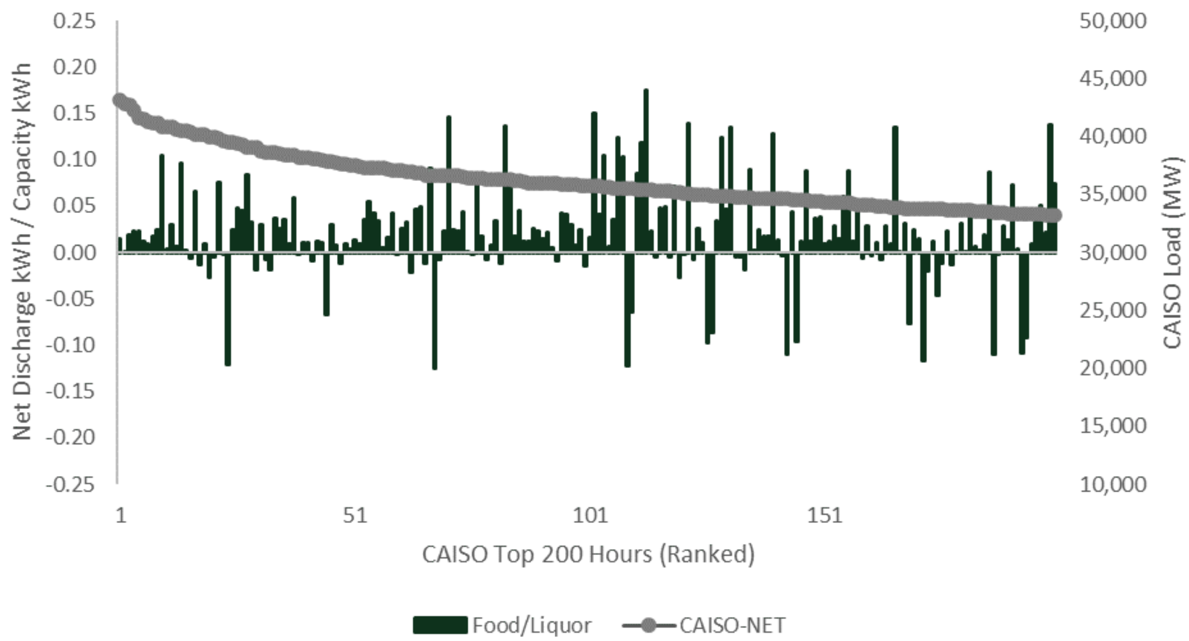


FIGURE C-3: NET DISCHARGE KWH FOR HOTELS DURING CAISO GROSS PEAKS

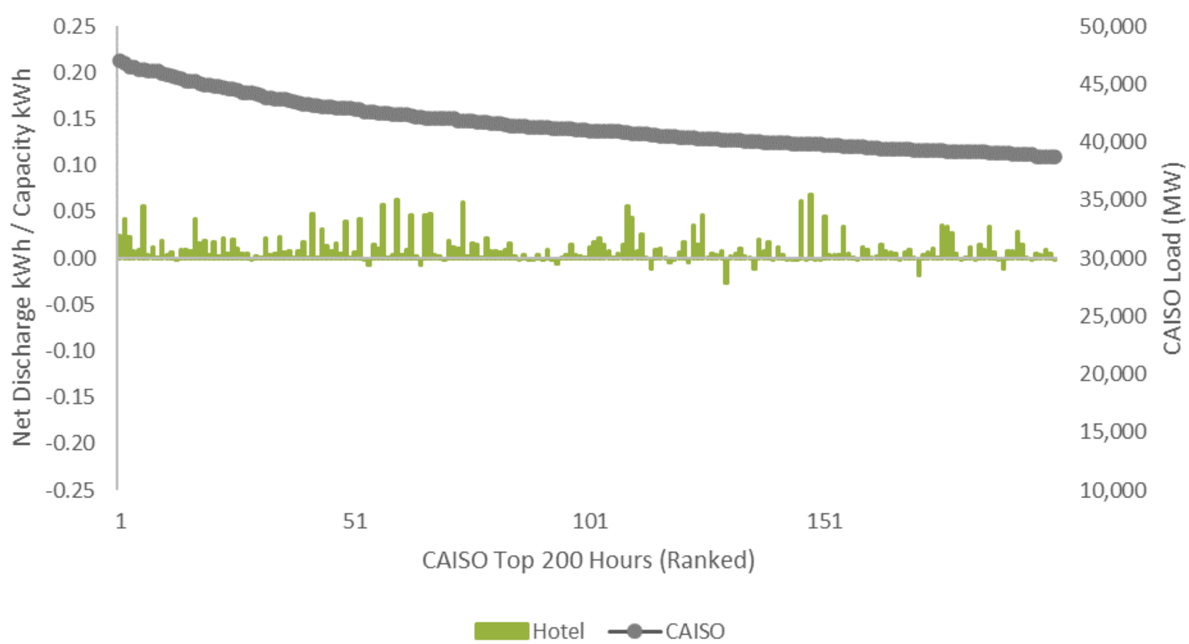


FIGURE C-4: NET DISCHARGE KWH FOR HOTELS DURING CAISO NET PEAKS

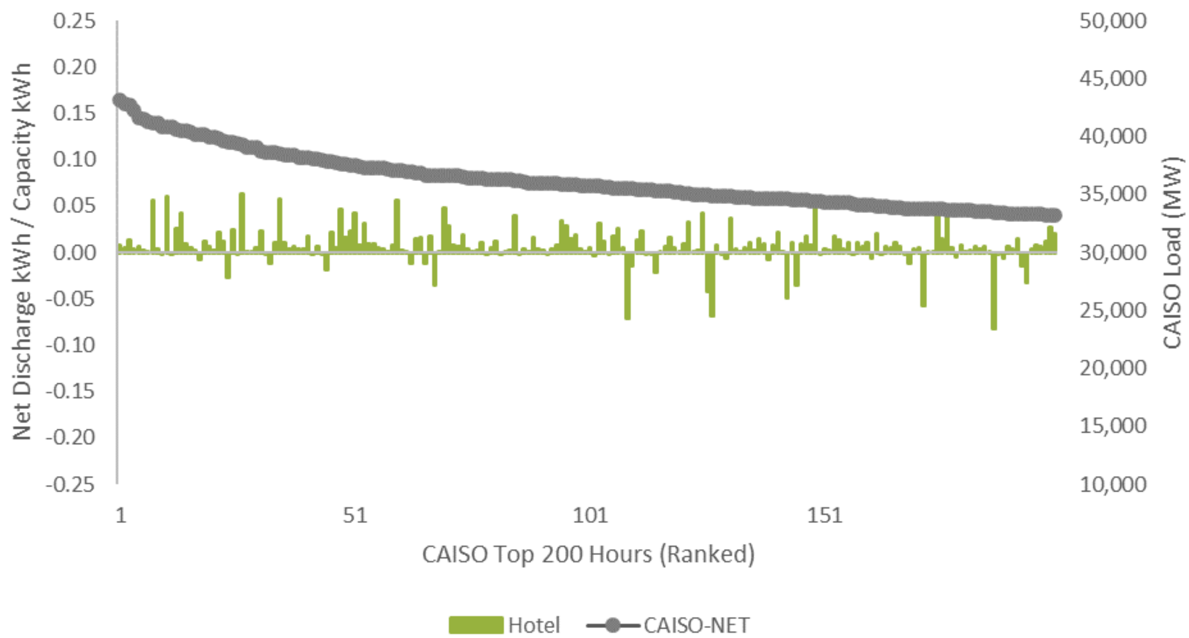


FIGURE C-5: NET DISCHARGE KWH FOR INDUSTRIAL FACILITIES DURING CAISO GROSS PEAKS

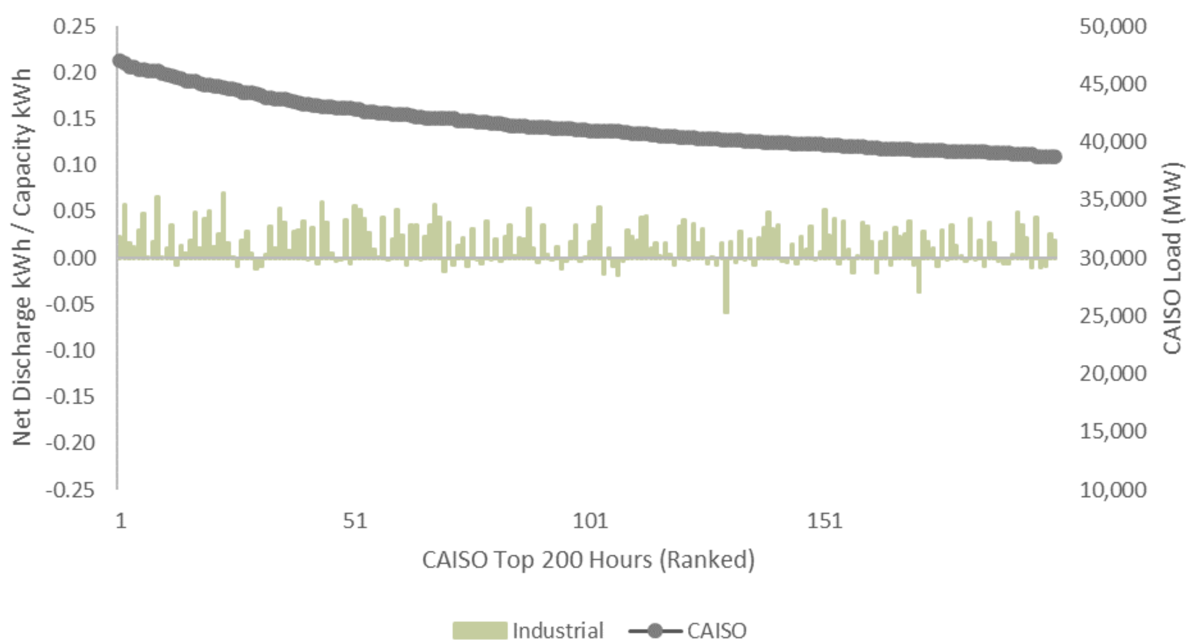


FIGURE C-6: NET DISCHARGE KWH FOR INDUSTRIAL FACILITIES DURING CAISO NET PEAKS

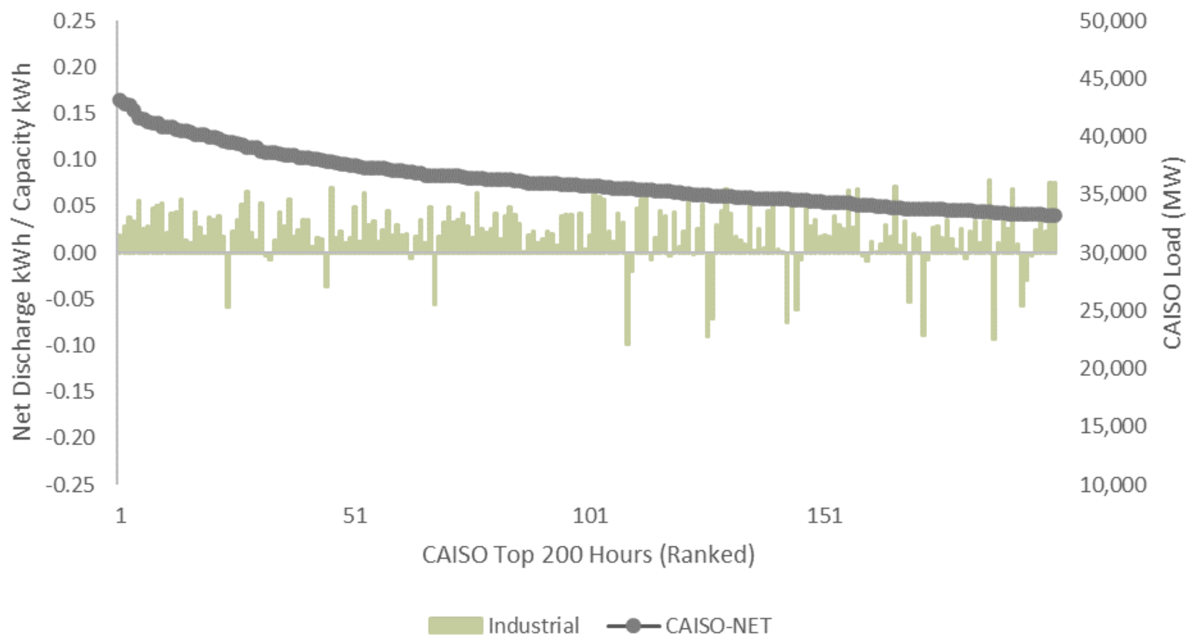


FIGURE C-7: NET DISCHARGE KWH FOR OFFICES DURING CAISO GROSS PEAKS

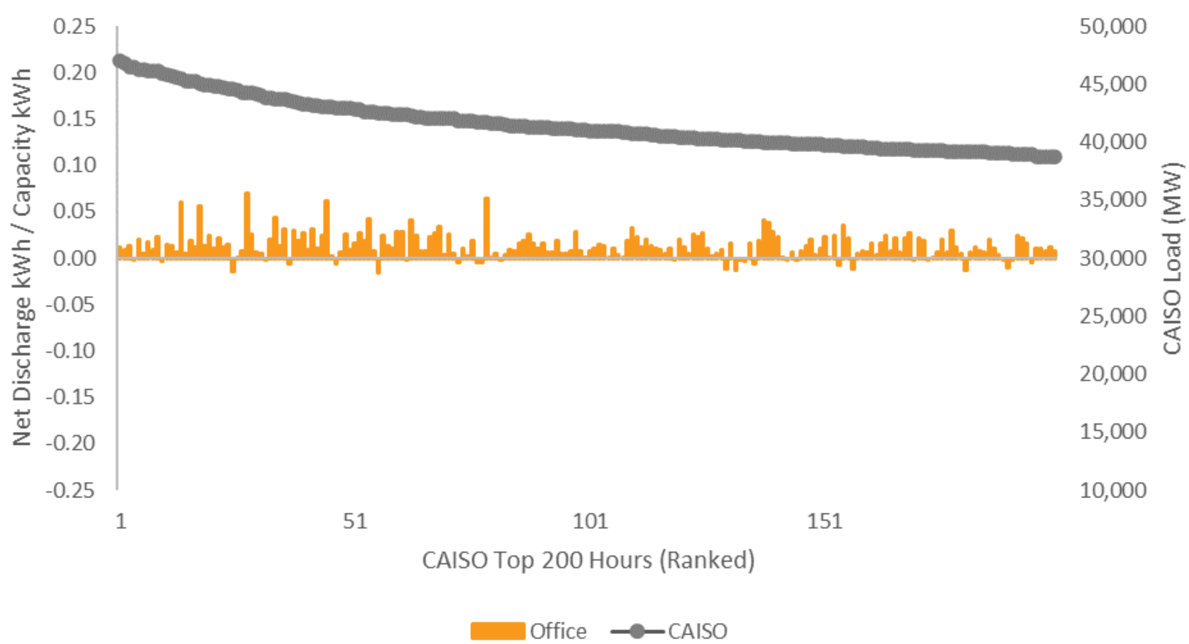


FIGURE C-8: NET DISCHARGE KWH FOR OFFICES DURING CAISO NET PEAKS

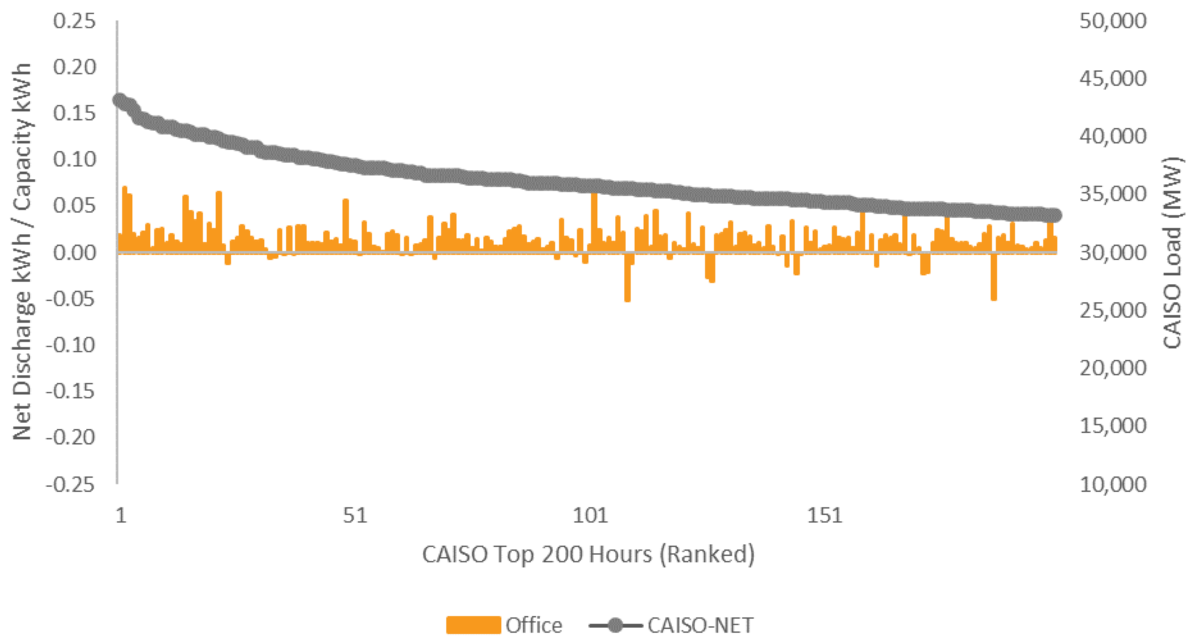


FIGURE C-9: NET DISCHARGE KWH FOR RETAIL STORES DURING CAISO GROSS PEAKS

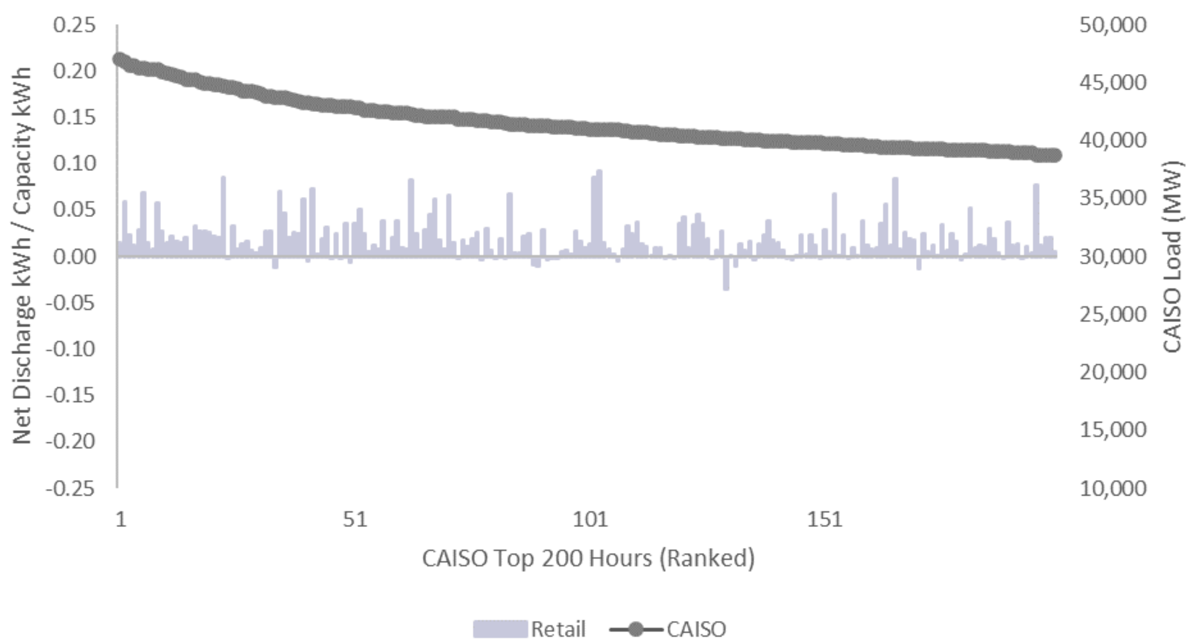


FIGURE C-10: NET DISCHARGE KWH FOR RETAIL STORES DURING CAISO NET PEAKS

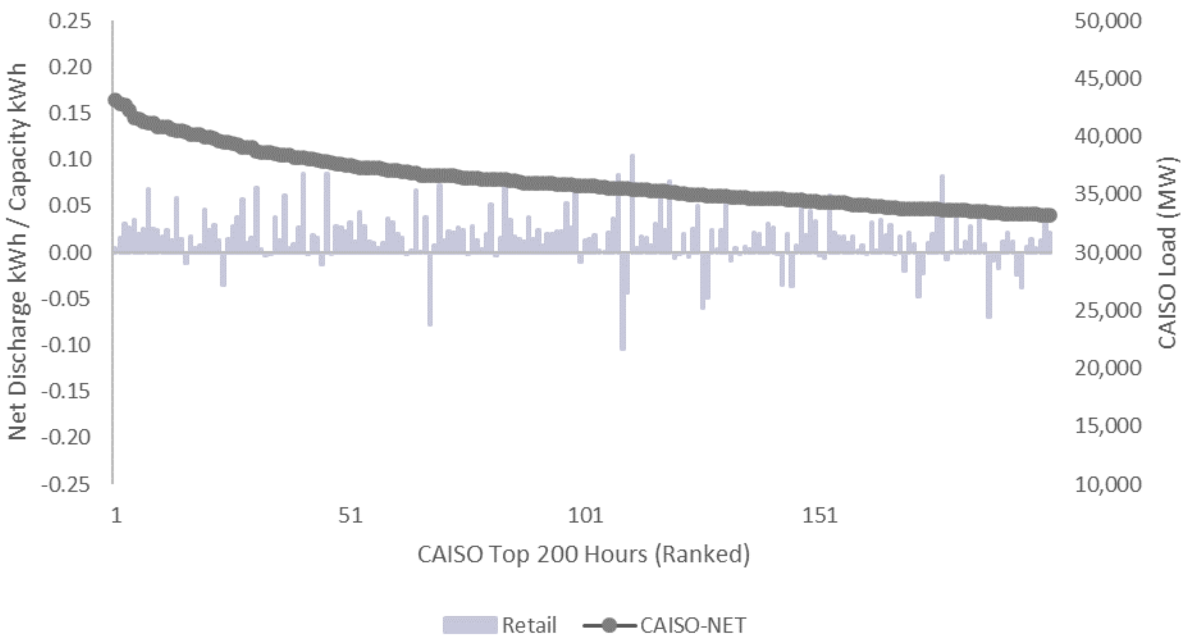


FIGURE C-11: NET DISCHARGE KWH FOR SCHOOLS DURING CAISO GROSS PEAKS

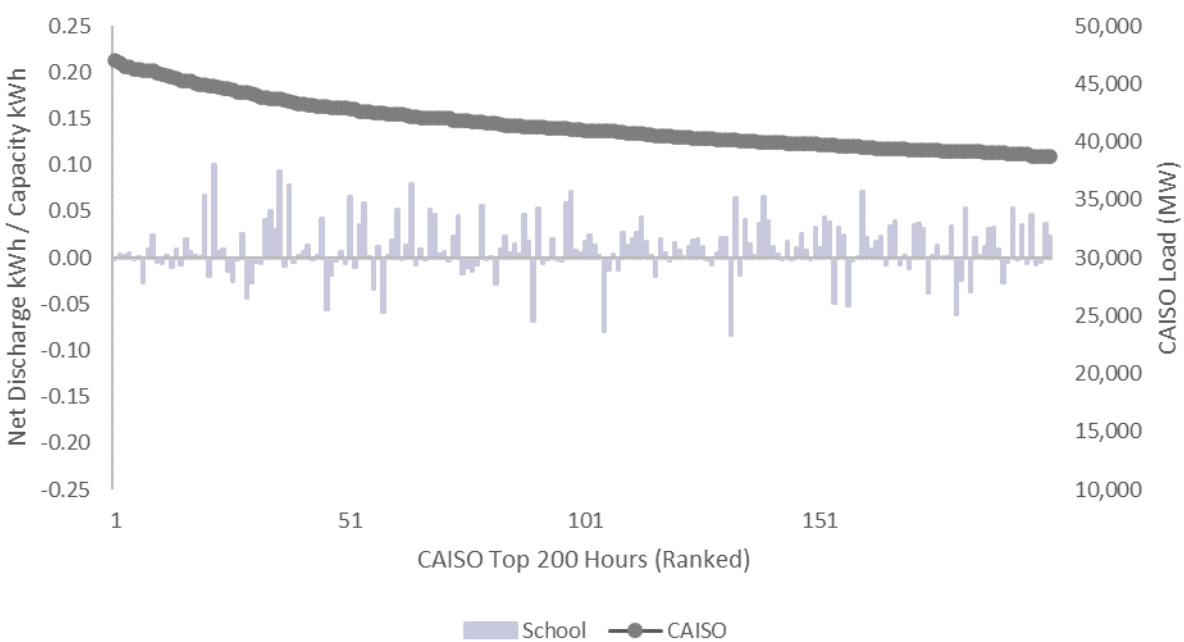
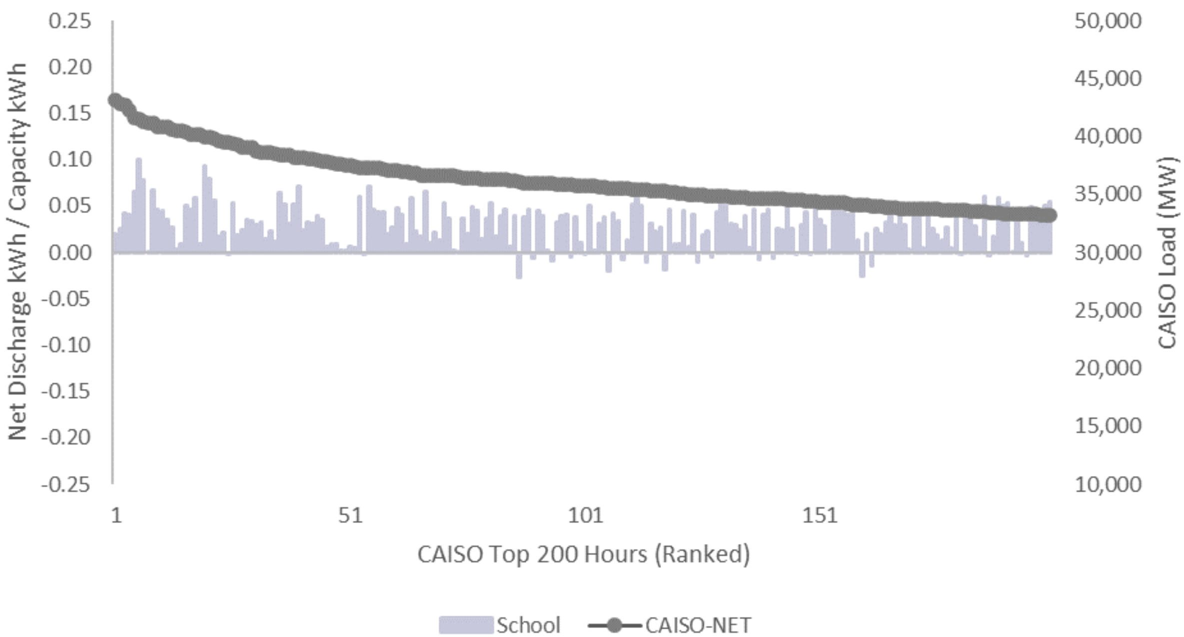


FIGURE C-12: NET DISCHARGE KWH FOR SCHOOLS DURING CAISO NET PEAKS



Percent Discharge and Charge kWh per kWh Rebated Capacity Heat Maps (Average Hourly by Month)

FIGURE C-13: RESIDENTIAL SYSTEMS WITH 4PM – 9PM ON-PEAK (PG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	-3%	-1%	-1%	-1%	0%	0%	0%
7	0%	0%	-1%	-1%	-3%	-10%	-6%	-4%	-3%	0%	0%	0%
8	-1%	-2%	-3%	-4%	-6%	-13%	-11%	-9%	-7%	-3%	-2%	-1%
9	-3%	-5%	-3%	-5%	-7%	-11%	-11%	-9%	-10%	-5%	-4%	-3%
10	-3%	-5%	-4%	-5%	-5%	-6%	-11%	-9%	-9%	-6%	-5%	-4%
11	-3%	-4%	-3%	-3%	-3%	-4%	-7%	-8%	-7%	-4%	-5%	-5%
12	-2%	-2%	-2%	-2%	-1%	-2%	-2%	-3%	-5%	-3%	-4%	-4%
13	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-2%	-3%
14	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	0%
15	0%	0%	1%	1%	1%	22%	24%	23%	23%	3%	2%	2%
16	2%	1%	1%	1%	1%	8%	7%	7%	5%	2%	3%	3%
17	2%	2%	2%	2%	3%	2%	2%	3%	2%	2%	3%	3%
18	2%	3%	2%	3%	3%	3%	3%	3%	2%	2%	2%	3%
19	2%	3%	3%	3%	3%	3%	3%	3%	2%	1%	2%	2%
20	1%	2%	2%	2%	3%	3%	2%	2%	2%	1%	1%	1%
21	1%	2%	1%	1%	2%	3%	2%	2%	1%	1%	1%	0%
22	0%	1%	0%	1%	2%	2%	1%	1%	1%	1%	1%	0%
23	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%

FIGURE C-14: RESIDENTIAL SYSTEMS WITH 4PM – 9PM ON-PEAK (SCE)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	1%	0%
1	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
2	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
3	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
4	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
5	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	1%	0%	-2%	-3%	-3%	-2%	-2%	-1%	0%	0%	0%
7	-1%	-2%	-4%	-8%	-10%	-8%	-8%	-6%	-5%	-4%	-2%	-1%
8	-5%	-8%	-9%	-12%	-15%	-11%	-13%	-11%	-10%	-9%	-9%	-5%
9	-10%	-13%	-10%	-11%	-13%	-12%	-13%	-12%	-13%	-12%	-13%	-10%
10	-11%	-11%	-8%	-8%	-8%	-9%	-10%	-10%	-10%	-11%	-12%	-11%
11	-8%	-8%	-5%	-4%	-4%	-5%	-6%	-6%	-6%	-8%	-8%	-8%
12	-5%	-4%	-3%	-3%	-2%	-3%	-3%	-3%	-4%	-4%	-5%	-5%
13	-3%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-3%
14	-1%	-1%	-1%	0%	0%	0%	0%	1%	1%	0%	0%	-1%
15	1%	0%	2%	4%	6%	6%	7%	8%	7%	6%	1%	1%
16	4%	3%	9%	13%	14%	14%	15%	15%	15%	15%	6%	5%
17	14%	13%	8%	8%	10%	10%	10%	10%	9%	9%	15%	13%
18	7%	7%	5%	5%	6%	6%	6%	5%	5%	5%	8%	6%
19	4%	5%	4%	4%	4%	4%	4%	3%	3%	3%	5%	4%
20	3%	4%	2%	2%	2%	2%	2%	2%	1%	1%	4%	3%
21	1%	2%	2%	2%	2%	2%	2%	1%	1%	1%	2%	1%
22	1%	2%	1%	1%	1%	1%	1%	1%	0%	1%	1%	1%
23	1%	1%	1%	1%	1%	1%	1%	0%	0%	1%	1%	0%

FIGURE C-15: RESIDENTIAL SYSTEMS WITH 4PM – 9PM ON-PEAK (SDG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	2%	1%	1%	2%	2%	1%	1%	1%	1%	1%	0%
1	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%
2	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	1%	0%
3	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%
4	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%
5	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
6	0%	1%	1%	0%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
7	0%	0%	-1%	-3%	-6%	-5%	-5%	-5%	-4%	-3%	-2%	-1%
8	-3%	-5%	-5%	-8%	-11%	-10%	-12%	-11%	-10%	-9%	-6%	-4%
9	-8%	-10%	-9%	-9%	-13%	-14%	-16%	-15%	-15%	-14%	-10%	-7%
10	-10%	-12%	-9%	-9%	-11%	-14%	-13%	-13%	-13%	-15%	-11%	-8%
11	-9%	-11%	-8%	-8%	-6%	-10%	-7%	-8%	-7%	-10%	-10%	-8%
12	-7%	-8%	-6%	-5%	-3%	-6%	-4%	-3%	-4%	-5%	-6%	-6%
13	-5%	-5%	-4%	-3%	-2%	-3%	-2%	-2%	-1%	-1%	-2%	-3%
14	-2%	-2%	-2%	-1%	-1%	0%	0%	0%	1%	1%	0%	0%
15	0%	0%	1%	2%	2%	11%	12%	13%	12%	13%	2%	1%
16	3%	3%	3%	3%	4%	7%	7%	9%	8%	9%	6%	5%
17	6%	6%	5%	5%	6%	6%	6%	7%	7%	7%	7%	6%
18	6%	8%	6%	6%	7%	7%	6%	6%	6%	6%	7%	5%
19	5%	6%	5%	5%	7%	7%	5%	4%	4%	4%	5%	4%
20	4%	5%	4%	5%	6%	5%	4%	3%	3%	3%	4%	4%
21	3%	5%	3%	3%	4%	3%	3%	2%	2%	2%	3%	2%
22	2%	3%	2%	2%	3%	2%	2%	1%	1%	1%	2%	1%
23	1%	2%	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%

FIGURE C-16: RESIDENTIAL SYSTEMS WITH 5PM – 8PM ON-PEAK (PG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0									0%	0%	0%	0%
1									0%	0%	0%	0%
2									0%	-1%	0%	0%
3									-1%	-1%	0%	0%
4									-1%	0%	0%	0%
5									0%	0%	0%	0%
6									-1%	0%	0%	0%
7									-6%	-1%	-1%	0%
8									-12%	-4%	-5%	-4%
9									-16%	-5%	-8%	-9%
10									-9%	-2%	-4%	-7%
11									-3%	0%	-2%	-2%
12									0%	0%	-1%	0%
13									0%	0%	0%	0%
14									4%	1%	0%	0%
15									35%	1%	2%	2%
16									9%	2%	2%	2%
17									3%	3%	6%	8%
18									3%	2%	6%	7%
19									0%	0%	5%	4%
20									0%	0%	0%	0%
21									0%	0%	0%	0%
22									0%	0%	0%	0%
23									0%	0%	0%	0%

FIGURE C-17: RESIDENTIAL SYSTEMS WITH 12PM – 6PM ON-PEAK (SCE)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%
1	0%	1%	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%
2	0%	1%	1%	0%	1%	1%	1%	1%	0%	0%	0%	0%
3	0%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%
4	0%	1%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	0%	0%
7	-1%	-2%	-3%	-4%	-6%	-5%	-5%	-4%	-4%	-3%	-3%	-1%
8	-4%	-7%	-7%	-9%	-11%	-8%	-10%	-9%	-8%	-7%	-7%	-5%
9	-9%	-11%	-9%	-10%	-10%	-9%	-12%	-12%	-12%	-10%	-11%	-8%
10	-10%	-10%	-7%	-6%	-6%	-8%	-8%	-8%	-9%	-9%	-10%	-9%
11	-6%	-5%	-1%	0%	-1%	-2%	-1%	0%	-2%	-2%	-6%	-6%
12	-1%	0%	0%	1%	1%	-1%	0%	1%	0%	-1%	-1%	-1%
13	0%	1%	0%	1%	1%	0%	1%	1%	0%	0%	1%	0%
14	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	3%	2%
15	2%	2%	3%	5%	5%	5%	5%	5%	5%	5%	3%	2%
16	7%	7%	5%	7%	7%	7%	6%	6%	8%	9%	5%	4%
17	7%	7%	4%	3%	3%	4%	3%	4%	4%	4%	10%	9%
18	3%	4%	3%	3%	3%	3%	3%	3%	3%	3%	4%	3%
19	2%	2%	2%	2%	2%	2%	3%	3%	3%	2%	3%	2%
20	1%	2%	1%	2%	2%	2%	2%	2%	2%	1%	2%	2%
21	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
22	1%	1%	0%	1%	1%	1%	1%	1%	1%	1%	1%	0%
23	-2%	-1%	0%	-1%	-1%	0%	0%	1%	-1%	0%	0%	0%

FIGURE C-18: RESIDENTIAL SYSTEMS WITH 11PM – 6PM ON-PEAK (SDG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	2%	2%	1%	1%	2%	1%	0%	0%	0%	0%	0%	0%
1	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
2	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
3	1%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
4	1%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
5	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	-1%	-3%	-2%	-2%	-1%	0%	0%	0%	0%
7	-1%	-1%	-2%	-4%	-7%	-5%	-5%	-3%	-3%	-2%	-1%	0%
8	-4%	-6%	-5%	-7%	-9%	-9%	-10%	-6%	-6%	-5%	-3%	-1%
9	-8%	-9%	-6%	-8%	-9%	-11%	-13%	-9%	-9%	-9%	-6%	-3%
10	-7%	-8%	-5%	-6%	-8%	-4%	-5%	-6%	-4%	-3%	-8%	-4%
11	-6%	-7%	-4%	-4%	-5%	-4%	-4%	-5%	-3%	-6%	-8%	-5%
12	-5%	-5%	-3%	-2%	-2%	-3%	-2%	-5%	-3%	-6%	-8%	-6%
13	-2%	-3%	-2%	-1%	0%	0%	0%	-3%	-3%	-3%	-4%	-5%
14	-1%	-2%	-1%	0%	1%	1%	1%	-1%	-1%	-1%	-1%	-1%
15	0%	0%	1%	2%	3%	4%	6%	6%	4%	5%	2%	1%
16	3%	3%	3%	3%	4%	5%	7%	7%	6%	7%	6%	5%
17	5%	6%	3%	4%	5%	5%	7%	8%	6%	7%	7%	5%
18	4%	5%	4%	4%	6%	6%	6%	7%	4%	5%	6%	3%
19	3%	4%	3%	4%	5%	4%	3%	3%	3%	4%	5%	3%
20	3%	4%	2%	2%	3%	2%	1%	1%	2%	1%	4%	1%
21	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%	3%	0%
22	2%	2%	1%	2%	2%	1%	1%	1%	1%	1%	1%	0%
23	1%	2%	1%	1%	2%	2%	1%	0%	0%	0%	1%	0%

FIGURE C-19: RESIDENTIAL SYSTEMS WITH 2PM – 9PM ON-PEAK (PG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	-1%	-1%	-1%	0%	0%	0%	0%	0%
7	0%	0%	-1%	-2%	-3%	-5%	-4%	-2%	-2%	-1%	0%	0%
8	-1%	-2%	-4%	-5%	-7%	-10%	-9%	-6%	-5%	-3%	-2%	-1%
9	-2%	-6%	-6%	-8%	-8%	-12%	-12%	-10%	-8%	-6%	-5%	-4%
10	-4%	-7%	-7%	-7%	-7%	-9%	-11%	-10%	-9%	-7%	-7%	-6%
11	-4%	-8%	-6%	-4%	-4%	-4%	-6%	-6%	-8%	-6%	-7%	-8%
12	-4%	-4%	-2%	-1%	-1%	-1%	-1%	-3%	-4%	-4%	-6%	-7%
13	-3%	-1%	0%	1%	2%	2%	2%	3%	2%	1%	-3%	-5%
14	0%	1%	1%	1%	2%	3%	2%	4%	3%	2%	4%	4%
15	1%	1%	1%	1%	2%	11%	8%	10%	9%	3%	3%	4%
16	2%	2%	2%	2%	3%	5%	4%	4%	4%	3%	3%	4%
17	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%	5%	6%
18	2%	4%	4%	4%	3%	4%	4%	3%	4%	3%	5%	5%
19	2%	4%	4%	4%	3%	3%	4%	3%	3%	3%	4%	3%
20	2%	3%	3%	3%	3%	3%	3%	2%	2%	1%	3%	2%
21	1%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	0%
22	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	1%	0%
23	0%	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%

VERDANT

FIGURE C-20: RESIDENTIAL SYSTEMS WITH 2PM – 8PM ON-PEAK (SCE)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
1	0%	1%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	-2%	-4%	-3%	-3%	-2%	-1%	-1%	0%	0%
7	-1%	-2%	-4%	-7%	-9%	-7%	-7%	-6%	-5%	-4%	-3%	-1%
8	-5%	-8%	-8%	-11%	-12%	-10%	-11%	-10%	-10%	-8%	-8%	-5%
9	-9%	-12%	-9%	-10%	-11%	-10%	-12%	-11%	-12%	-10%	-10%	-8%
10	-10%	-11%	-8%	-7%	-7%	-8%	-9%	-9%	-9%	-10%	-10%	-9%
11	-8%	-8%	-5%	-4%	-4%	-5%	-5%	-5%	-6%	-7%	-7%	-7%
12	-5%	-4%	-3%	-2%	-2%	-3%	-3%	-2%	-3%	-4%	-4%	-4%
13	-2%	-2%	0%	2%	2%	2%	3%	4%	3%	2%	-2%	-2%
14	1%	2%	1%	2%	3%	3%	4%	4%	4%	3%	2%	1%
15	2%	2%	7%	10%	11%	11%	12%	12%	7%	4%	3%	2%
16	11%	11%	7%	7%	8%	8%	8%	8%	12%	14%	4%	4%
17	7%	7%	4%	4%	4%	4%	5%	4%	5%	6%	14%	11%
18	4%	5%	4%	4%	4%	4%	4%	3%	3%	3%	5%	4%
19	3%	4%	3%	3%	3%	3%	3%	2%	2%	2%	3%	3%
20	2%	3%	2%	2%	2%	2%	2%	2%	1%	1%	2%	2%
21	2%	2%	1%	1%	1%	1%	1%	1%	0%	1%	1%	1%
22	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	1%	0%
23	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%

FIGURE C-21: RESIDENTIAL SYSTEMS ON NON-TOU RATE (SCE)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	1%	0%
1	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%
2	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	-1%	-2%	-2%	-1%	-1%	-1%	0%	0%	0%
7	0%	-1%	-2%	-3%	-5%	-4%	-4%	-3%	-3%	-2%	-2%	-1%
8	-2%	-3%	-4%	-5%	-7%	-6%	-7%	-6%	-6%	-5%	-5%	-3%
9	-4%	-5%	-4%	-6%	-7%	-7%	-8%	-7%	-7%	-6%	-7%	-5%
10	-4%	-5%	-4%	-5%	-5%	-6%	-7%	-7%	-7%	-6%	-7%	-6%
11	-4%	-4%	-3%	-3%	-3%	-4%	-5%	-5%	-5%	-5%	-6%	-6%
12	-3%	-3%	-2%	-2%	-2%	-3%	-2%	-2%	-2%	-3%	-4%	-4%
13	-2%	-2%	-1%	-1%	0%	0%	1%	1%	1%	0%	-1%	-2%
14	0%	0%	0%	0%	0%	1%	2%	2%	2%	2%	1%	0%
15	1%	0%	0%	1%	2%	2%	3%	3%	4%	3%	2%	2%
16	2%	2%	2%	3%	3%	4%	4%	4%	5%	5%	4%	3%
17	3%	4%	3%	3%	4%	4%	4%	4%	4%	4%	5%	4%
18	2%	3%	3%	3%	4%	4%	4%	3%	3%	3%	4%	3%
19	2%	2%	2%	3%	3%	3%	3%	2%	2%	2%	3%	2%
20	1%	2%	2%	2%	2%	2%	2%	2%	2%	1%	2%	2%
21	1%	1%	1%	1%	2%	2%	1%	1%	1%	1%	2%	1%
22	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	1%	1%
23	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	1%	0%

VERDANT

FIGURE C-22: RESIDENTIAL SYSTEMS ON NON-TOU RATE (SDG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
1	0%	0%	0%	1%	1%	1%	1%	1%	0%	1%	1%	0%
2	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%
3	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
6	0%	0%	0%	-1%	-2%	-1%	-1%	-1%	-1%	0%	0%	0%
7	-1%	-1%	-2%	-4%	-5%	-4%	-4%	-5%	-4%	-4%	-2%	-1%
8	-3%	-5%	-5%	-6%	-8%	-7%	-9%	-9%	-8%	-8%	-7%	-3%
9	-7%	-8%	-6%	-7%	-9%	-10%	-11%	-12%	-11%	-11%	-10%	-6%
10	-7%	-8%	-6%	-5%	-5%	-8%	-8%	-9%	-8%	-10%	-10%	-7%
11	-6%	-5%	-4%	-3%	-3%	-5%	-5%	-5%	-5%	-6%	-6%	-5%
12	-4%	-3%	-2%	-2%	-2%	-4%	-3%	-2%	-2%	-3%	-4%	-4%
13	-2%	-1%	-1%	-1%	-1%	-2%	-1%	0%	0%	-1%	-2%	-2%
14	0%	0%	0%	-1%	0%	0%	1%	1%	1%	0%	-1%	-1%
15	1%	1%	1%	1%	1%	5%	6%	8%	7%	8%	2%	1%
16	4%	3%	2%	2%	2%	3%	3%	5%	5%	5%	5%	4%
17	5%	5%	4%	4%	4%	4%	4%	5%	5%	6%	7%	5%
18	4%	5%	4%	5%	5%	5%	5%	5%	4%	4%	5%	4%
19	3%	3%	3%	4%	4%	5%	4%	3%	3%	3%	4%	3%
20	2%	2%	2%	2%	3%	3%	3%	2%	2%	2%	3%	2%
21	1%	1%	1%	1%	2%	2%	2%	2%	1%	1%	2%	1%
22	1%	1%	1%	1%	1%	2%	1%	1%	1%	1%	2%	1%
23	1%	1%	1%	2%	2%	2%	2%	2%	1%	2%	1%	1%

FIGURE C-23: NONRESIDENTIAL SYSTEMS WITH 12PM – 6PM ON-PEAK (PG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-1%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	0%	0%	0%
1	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
2	-1%	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%
3	-1%	-1%	-1%	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%
4	-1%	-1%	0%	0%	0%	1%	1%	1%	0%	0%	-1%	-1%
5	0%	0%	1%	1%	0%	0%	1%	1%	1%	1%	0%	0%
6	1%	1%	0%	-2%	-3%	-3%	-3%	-2%	-1%	0%	1%	1%
7	1%	0%	-2%	-3%	-4%	-4%	-5%	-3%	-3%	-2%	-1%	0%
8	0%	-2%	-3%	-4%	-4%	-4%	-4%	-3%	-4%	-4%	-4%	-2%
9	-2%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-4%	-4%	-4%
10	-3%	-3%	-3%	-2%	-2%	-2%	-2%	-2%	-3%	-3%	-4%	-4%
11	-2%	-2%	-2%	-1%	0%	0%	0%	0%	0%	-1%	-2%	-3%
12	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%	0%	-1%	-2%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%
14	0%	0%	0%	0%	1%	0%	0%	0%	1%	1%	0%	0%
15	0%	0%	0%	0%	2%	2%	2%	2%	2%	2%	0%	0%
16	0%	0%	0%	0%	5%	6%	7%	6%	6%	7%	1%	1%
17	1%	1%	1%	1%	0%	0%	0%	1%	2%	3%	1%	1%
18	1%	1%	2%	3%	2%	2%	2%	3%	2%	2%	2%	2%
19	1%	2%	2%	5%	2%	2%	3%	2%	2%	2%	3%	3%
20	5%	5%	5%	2%	-1%	-1%	0%	-1%	-2%	-1%	5%	4%
21	0%	0%	0%	-3%	-5%	-5%	-5%	-6%	-6%	-6%	1%	1%
22	-7%	-7%	-5%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-4%	-4%
23	-2%	-1%	-2%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-1%

VERDANT

FIGURE C-24: NONRESIDENTIAL SYSTEMS WITH 12PM – 6PM ON-PEAK (SCE)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	0%	0%	0%	1%	1%	1%	0%	0%	-1%	0%	0%	0%
1	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%
2	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	0%
3	0%	0%	1%	2%	2%	2%	1%	0%	0%	0%	0%	0%
4	1%	1%	1%	3%	3%	3%	2%	1%	0%	1%	0%	1%
5	1%	1%	3%	3%	3%	2%	3%	2%	1%	1%	1%	1%
6	2%	3%	3%	0%	-2%	-2%	-1%	0%	0%	1%	1%	2%
7	3%	3%	-1%	-7%	-8%	-6%	-5%	-3%	-4%	-3%	-2%	1%
8	-2%	-3%	-7%	-12%	-13%	-10%	-9%	-8%	-7%	-7%	-7%	-4%
9	-9%	-9%	-10%	-11%	-10%	-10%	-10%	-8%	-8%	-8%	-10%	-8%
10	-12%	-12%	-9%	-7%	-6%	-7%	-8%	-7%	-7%	-8%	-10%	-10%
11	-10%	-10%	-6%	-4%	-3%	-4%	-4%	-4%	-4%	-6%	-6%	-8%
12	-7%	-6%	-3%	-2%	-2%	-2%	-2%	-2%	-2%	-3%	-3%	-5%
13	-3%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	-1%	-2%
14	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%
15	0%	0%	-1%	0%	0%	0%	0%	-1%	0%	0%	1%	0%
16	1%	1%	0%	0%	0%	0%	1%	1%	2%	2%	2%	2%
17	3%	3%	2%	2%	2%	1%	2%	4%	3%	3%	3%	3%
18	4%	4%	3%	3%	4%	4%	4%	4%	4%	4%	3%	3%
19	4%	5%	4%	5%	5%	4%	4%	4%	4%	4%	3%	3%
20	4%	5%	4%	4%	4%	4%	4%	3%	3%	3%	4%	3%
21	3%	3%	2%	2%	2%	2%	2%	2%	2%	1%	3%	3%
22	1%	1%	2%	3%	3%	2%	2%	1%	1%	2%	1%	1%
23	2%	2%	0%	1%	0%	0%	0%	-1%	-1%	0%	2%	2%

FIGURE C-25: NONRESIDENTIAL SYSTEMS WITH 11PM – 6PM ON-PEAK (SDG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	-1%	-1%	2%	2%	4%	2%	0%	0%	0%	0%	1%	0%
1	-1%	-1%	1%	2%	2%	1%	1%	1%	1%	2%	3%	2%
2	-1%	-1%	1%	2%	2%	1%	1%	1%	-1%	-1%	-1%	-1%
3	-1%	-1%	1%	2%	3%	2%	3%	1%	0%	-1%	0%	0%
4	0%	0%	1%	3%	3%	2%	3%	2%	0%	0%	0%	1%
5	0%	0%	0%	1%	1%	1%	2%	3%	1%	1%	1%	1%
6	2%	2%	0%	-1%	-3%	-1%	0%	2%	1%	1%	0%	0%
7	2%	2%	-2%	-5%	-7%	-3%	-3%	-2%	-1%	-1%	-2%	0%
8	0%	0%	-4%	-7%	-9%	-4%	-6%	-6%	-3%	-3%	-6%	-3%
9	-4%	-3%	-5%	-7%	-8%	-5%	-7%	-7%	-4%	-4%	-7%	-6%
10	-5%	-5%	-5%	-5%	-6%	-4%	-5%	-6%	-3%	-5%	-5%	-6%
11	-5%	-6%	-3%	-3%	-3%	-4%	-3%	-5%	-2%	-3%	-4%	-5%
12	-4%	-5%	-2%	-2%	-2%	-2%	-1%	-2%	-1%	-1%	-1%	-4%
13	-3%	-3%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%	-2%
14	-1%	-1%	-1%	0%	-1%	0%	0%	0%	0%	1%	0%	0%
15	0%	0%	0%	0%	0%	1%	0%	3%	2%	2%	1%	0%
16	1%	1%	2%	4%	3%	2%	1%	4%	2%	4%	3%	1%
17	6%	6%	5%	4%	4%	0%	1%	5%	0%	2%	5%	4%
18	7%	7%	6%	6%	6%	1%	2%	3%	1%	1%	4%	4%
19	7%	7%	0%	-1%	0%	2%	1%	1%	1%	1%	4%	4%
20	0%	0%	-1%	-1%	0%	1%	0%	0%	0%	1%	-1%	0%
21	-1%	0%	-1%	-1%	1%	2%	1%	0%	1%	0%	0%	0%
22	-3%	-2%	0%	0%	1%	0%	0%	-1%	0%	1%	1%	1%
23	-2%	-2%	-1%	0%	1%	1%	1%	-1%	0%	0%	1%	1%

FIGURE C-26: NONRESIDENTIAL SYSTEMS WITH 4PM – 9PM ON-PEAK (PG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	1%	4%	3%	1%	0%	-1%	-2%	-2%	-1%	0%	0%	-2%
1	-3%	-2%	-1%	-1%	-1%	0%	-2%	-2%	-2%	-1%	-1%	-1%
2	-1%	-2%	-2%	-1%	-1%	0%	-1%	-1%	-1%	-1%	-2%	-2%
3	-1%	-2%	-1%	0%	0%	0%	-1%	-2%	-2%	-2%	-1%	-2%
4	-2%	-2%	-1%	-1%	0%	0%	-1%	-1%	-2%	-2%	-2%	-2%
5	-1%	-2%	-1%	-1%	0%	0%	0%	1%	0%	0%	-2%	-2%
6	-1%	-1%	0%	1%	0%	0%	-1%	-1%	0%	1%	0%	-1%
7	-1%	-1%	-1%	-1%	-1%	0%	-1%	-1%	0%	0%	-1%	-1%
8	-3%	0%	0%	-1%	-1%	-1%	-1%	0%	0%	0%	-1%	-1%
9	-3%	-1%	-1%	0%	0%	0%	1%	2%	0%	2%	0%	0%
10	-2%	-1%	-1%	-1%	1%	0%	1%	1%	0%	-1%	0%	1%
11	-2%	-1%	-1%	-1%	0%	0%	-2%	-1%	-2%	-2%	-1%	0%
12	-1%	-1%	0%	0%	0%	-1%	-1%	-2%	-2%	-2%	-1%	0%
13	-1%	0%	0%	0%	0%	0%	0%	-1%	0%	-1%	0%	0%
14	-2%	0%	0%	0%	0%	-1%	0%	0%	0%	-1%	0%	0%
15	-1%	-1%	0%	0%	2%	2%	3%	1%	1%	0%	0%	0%
16	2%	0%	0%	0%	8%	5%	4%	1%	1%	1%	0%	1%
17	2%	0%	0%	0%	0%	0%	1%	1%	2%	1%	0%	0%
18	1%	0%	0%	0%	0%	1%	1%	2%	2%	2%	1%	1%
19	2%	-1%	0%	6%	1%	1%	1%	4%	4%	4%	2%	2%
20	1%	0%	5%	0%	-6%	-5%	-3%	-1%	-2%	-2%	5%	3%
21	-3%	-1%	-2%	-8%	-9%	-6%	-4%	-1%	-1%	-4%	-3%	-4%
22	-2%	-1%	-8%	-3%	-2%	-2%	-3%	-6%	-6%	-2%	-3%	-3%
23	-3%	-1%	-1%	-1%	-1%	-2%	-3%	-4%	-4%	-2%	0%	1%

FIGURE C-27: NONRESIDENTIAL SYSTEMS WITH 4PM – 9PM ON-PEAK (SCE)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-1%
1	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	0%	-1%	-1%	-1%
2	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	-1%
3	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%	-1%	0%	0%	-1%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%
6	1%	1%	2%	2%	2%	1%	1%	1%	0%	1%	0%	1%
7	3%	2%	-3%	-5%	-6%	-1%	-1%	-1%	-1%	-4%	1%	3%
8	-5%	-5%	-5%	-5%	-5%	-1%	-1%	-1%	-1%	-4%	-5%	-3%
9	-5%	-5%	-3%	-3%	-3%	-1%	-1%	-1%	-1%	-2%	-4%	-4%
10	-3%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-2%	-2%
11	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%
12	-2%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	-1%	-1%	-1%
13	-1%	0%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%	-1%
14	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
15	0%	0%	1%	1%	1%	3%	2%	3%	2%	1%	0%	-1%
16	2%	3%	1%	1%	1%	2%	2%	3%	2%	1%	2%	1%
17	2%	2%	1%	1%	1%	2%	2%	3%	2%	2%	2%	2%
18	2%	2%	2%	2%	3%	3%	3%	3%	3%	2%	1%	1%
19	2%	2%	5%	6%	6%	7%	7%	6%	6%	5%	2%	2%
20	5%	5%	0%	-1%	-1%	-8%	-8%	-8%	-8%	-2%	5%	4%
21	-2%	-2%	-2%	-2%	-3%	-6%	-6%	-7%	-5%	-2%	-2%	-3%
22	-3%	-3%	-2%	-1%	-2%	-3%	-3%	-4%	-2%	-1%	-2%	-2%
23	-2%	-2%	-1%	-1%	-1%	-2%	-2%	-3%	-2%	-1%	-1%	-2%

FIGURE C-28: NONRESIDENTIAL SYSTEMS WITH 4PM – 9PM ON-PEAK (SDG&E)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	-7%	-8%	-5%	-3%	-3%	-5%	-6%	-6%	-6%	-6%	-7%	-5%
1	-5%	-5%	-2%	-2%	-1%	-2%	-3%	-3%	-2%	-2%	-4%	-3%
2	-2%	-2%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-2%	-2%	-3%
3	-2%	-2%	-1%	-1%	0%	-1%	-1%	-1%	-2%	-3%	-1%	-2%
4	-2%	-2%	-1%	-1%	0%	-1%	0%	-1%	-2%	-2%	-1%	-2%
5	-1%	-1%	0%	-1%	0%	-1%	-1%	0%	-1%	-1%	-1%	-1%
6	0%	0%	-1%	-1%	-1%	-1%	-1%	0%	0%	1%	0%	0%
7	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	1%
8	0%	0%	1%	1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
9	0%	-1%	-2%	-3%	-1%	-1%	-1%	0%	-1%	-1%	-2%	-2%
10	0%	-1%	-2%	-2%	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%
11	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%
14	0%	0%	0%	0%	0%	0%	0%	0%	-1%	0%	0%	-1%
15	0%	-1%	1%	2%	2%	3%	3%	3%	3%	2%	0%	-1%
16	2%	2%	1%	1%	1%	2%	2%	2%	1%	2%	2%	2%
17	2%	2%	1%	0%	1%	1%	1%	1%	1%	2%	2%	3%
18	1%	3%	3%	2%	2%	2%	3%	2%	2%	2%	2%	3%
19	2%	3%	6%	6%	4%	5%	7%	6%	7%	7%	2%	2%
20	6%	7%	0%	-2%	-3%	-2%	-2%	-2%	-1%	-1%	5%	3%
21	-3%	-3%	-3%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-2%
22	-4%	-4%	-2%	0%	-1%	0%	0%	0%	0%	0%	-1%	-1%
23	-2%	-2%	-6%	-6%	-6%	-8%	-9%	-9%	-9%	-9%	0%	0%

FIGURE C-29: GROCERY STORES (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	1%	1%	2%	1%	1%	1%	1%	0%	0%	0%	0%	0%
1	1%	2%	2%	1%	1%	1%	0%	0%	1%	2%	2%	3%
2	1%	1%	1%	1%	0%	1%	1%	0%	1%	1%	1%	1%
3	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
4	1%	1%	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%
5	1%	0%	2%	1%	2%	1%	2%	1%	1%	1%	1%	2%
6	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	2%	3%
7	3%	2%	1%	1%	0%	0%	0%	0%	1%	1%	2%	7%
8	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%
9	0%	0%	0%	1%	0%	0%	0%	0%	1%	0%	0%	0%
10	0%	0%	0%	1%	1%	0%	0%	1%	1%	0%	0%	0%
11	1%	1%	0%	0%	1%	0%	0%	1%	1%	1%	1%	1%
12	1%	1%	0%	1%	1%	1%	1%	1%	1%	0%	1%	1%
13	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
14	1%	1%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%
15	1%	1%	1%	1%	1%	2%	2%	3%	2%	2%	1%	1%
16	2%	2%	1%	1%	2%	3%	3%	3%	2%	4%	2%	2%
17	2%	2%	1%	1%	1%	0%	1%	3%	1%	1%	1%	2%
18	2%	2%	2%	2%	4%	3%	4%	3%	4%	2%	1%	2%
19	2%	2%	6%	10%	11%	9%	13%	9%	14%	10%	2%	2%
20	10%	9%	2%	0%	0%	0%	1%	0%	0%	0%	11%	8%
21	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	2%	2%	1%	1%	1%	0%	1%

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	-1%	-2%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-2%
1	-2%	-2%	-2%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-2%	-3%
2	-1%	-1%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	-2%	-2%	-4%
3	-1%	-1%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-2%	-3%
4	-1%	-1%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	-2%	-2%	-3%
5	-1%	-1%	-2%	-1%	-1%	-2%	-1%	-1%	-2%	-1%	-2%	-2%
6	-1%	-1%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-2%
7	-1%	-1%	-6%	-8%	-11%	-1%	-3%	-2%	-1%	-10%	-1%	-2%
8	-10%	-10%	-6%	-6%	-8%	-1%	-2%	-1%	-1%	-8%	-11%	-9%
9	-8%	-8%	-3%	-4%	-3%	-1%	-1%	-1%	-1%	-3%	-8%	-7%
10	-4%	-3%	-1%	-2%	-1%	-1%	-1%	0%	-1%	-1%	-3%	-4%
11	-2%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%
12	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
13	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
14	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-2%
15	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	-1%	0%	-1%	-2%
16	0%	-1%	0%	0%	-1%	-1%	-1%	-1%	-1%	0%	-1%	-1%
17	-1%	-1%	0%	-1%	-1%	-3%	-2%	-2%	-1%	-1%	-1%	-1%
18	-1%	-1%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
19	-1%	-1%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
20	-1%	-1%	-1%	-2%	-1%	-8%	-11%	-10%	-13%	-2%	0%	-1%
21	-3%	-3%	-2%	-2%	-1%	-7%	-11%	-11%	-10%	-3%	-2%	-3%
22	-3%	-3%	-2%	-1%	-2%	-3%	-5%	-6%	-3%	-2%	-2%	-3%
23	-2%	-2%	-2%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-2%	-2%

VERDANT

FIGURE C-30: HOTELS (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	-2%	-2%	-1%	-1%	-2%	-1%	-1%	-1%	0%	0%	-1%	-1%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	-1%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	-1%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4	-1%	0%	0%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6	0%	0%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%
7	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	7	-1%	0%	-1%	-1%	-1%	-1%	0%	0%	0%	-1%	0%	0%
8	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	8	-2%	-2%	0%	0%	-1%	-1%	0%	0%	0%	0%	-1%	-1%
9	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	9	0%	0%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%	-1%
10	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	10	0%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	11	0%	0%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	12	0%	-1%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%	13	-1%	-1%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	14	-1%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	2%	3%	1%	1%	2%	1%	0%	0%	15	-1%	0%	-1%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
16	0%	1%	0%	1%	5%	6%	4%	4%	4%	1%	1%	0%	16	-1%	0%	-1%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
17	1%	1%	0%	1%	1%	1%	1%	1%	0%	1%	1%	1%	17	0%	0%	-1%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
18	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	18	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
19	1%	1%	2%	4%	2%	2%	2%	2%	1%	1%	0%	1%	19	0%	0%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%
20	10%	7%	3%	2%	1%	0%	0%	0%	0%	0%	1%	1%	20	0%	0%	-1%	-2%	-3%	-6%	-5%	-3%	-5%	-2%	0%	-1%
21	2%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	21	-7%	-6%	-4%	-3%	-4%	-6%	-3%	-4%	-4%	-2%	-1%	-2%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	22	-7%	-6%	-6%	-2%	-4%	-3%	-2%	-3%	-3%	-1%	-1%	-2%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	23	-1%	-2%	-2%	-2%	-3%	-3%	-2%	-3%	-2%	-2%	-1%	-1%

FIGURE C-31: INDUSTRIAL FACILITIES (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-5%	-4%	-3%	-2%	-2%	-3%	-3%	-4%	-4%	-3%	-3%	-3%	0	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
1	-4%	-3%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	1	1%	1%	1%	1%	1%	1%	1%	1%	2%	1%	1%	1%
2	-2%	-2%	-2%	-2%	-2%	-1%	-2%	-1%	-2%	-2%	-2%	-2%	2	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
3	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	3	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
4	-2%	-2%	-2%	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-1%	-1%	4	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
5	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	5	1%	1%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%
6	-1%	-1%	-1%	-2%	-1%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	6	2%	2%	3%	3%	3%	2%	2%	2%	1%	2%	2%	2%
7	-1%	-1%	-5%	-7%	-7%	-2%	-2%	-2%	-2%	-5%	-2%	-1%	7	4%	3%	2%	1%	2%	1%	1%	1%	1%	2%	2%	3%
8	-6%	-6%	-6%	-5%	-6%	-2%	-2%	-2%	-2%	-5%	-6%	-5%	8	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	2%
9	-5%	-6%	-4%	-4%	-3%	-2%	-2%	-2%	-2%	-3%	-6%	-5%	9	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
10	-3%	-4%	-3%	-3%	-3%	-2%	-2%	-2%	-2%	-3%	-3%	-3%	10	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
11	-3%	-3%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-2%	-2%	-2%	11	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	1%	1%
12	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	12	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
13	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-2%	13	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
14	-2%	-1%	-2%	-1%	-2%	-2%	-2%	-2%	-1%	-2%	-1%	-2%	14	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
15	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	-1%	-1%	15	1%	1%	2%	2%	3%	3%	3%	3%	3%	3%	1%	1%
16	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	-1%	-1%	-1%	-1%	16	2%	2%	2%	1%	4%	4%	4%	4%	3%	3%	2%	2%
17	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	17	2%	2%	2%	2%	2%	2%	2%	3%	2%	3%	2%	2%
18	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	18	2%	2%	3%	4%	4%	4%	4%	4%	3%	3%	2%	2%
19	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	19	3%	3%	7%	9%	7%	8%	8%	7%	8%	8%	3%	3%
20	-1%	-1%	-2%	-3%	-4%	-10%	-9%	-7%	-7%	-3%	-1%	-1%	20	8%	8%	4%	2%	1%	1%	1%	1%	1%	1%	7%	6%
21	-3%	-3%	-3%	-4%	-4%	-7%	-7%	-6%	-5%	-4%	-3%	-4%	21	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%
22	-4%	-4%	-3%	-2%	-2%	-3%	-3%	-5%	-4%	-2%	-3%	-3%	22	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
23	-2%	-2%	-3%	-3%	-3%	-4%	-5%	-5%	-5%	-5%	-1%	-2%	23	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

FIGURE C-32: OFFICES (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%	0%	0	-4%	-5%	-4%	-4%	-4%	-4%	-5%	-4%	-2%	-2%	-3%	-3%
1	2%	2%	2%	1%	1%	1%	1%	1%	0%	1%	1%	1%	1	-4%	-4%	-4%	-4%	-4%	-4%	-5%	-4%	-2%	-2%	-2%	-2%
2	1%	2%	2%	2%	2%	1%	1%	1%	1%	0%	0%	0%	2	-3%	-3%	-3%	-3%	-3%	-4%	-4%	-3%	-1%	-2%	-2%	-2%
3	1%	1%	1%	2%	2%	2%	1%	1%	0%	0%	0%	0%	3	-2%	-2%	-2%	-3%	-3%	-3%	-3%	-2%	-1%	-1%	-2%	-2%
4	2%	1%	2%	2%	2%	3%	3%	2%	1%	1%	0%	0%	4	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%
5	2%	2%	2%	2%	2%	3%	3%	2%	1%	1%	1%	1%	5	-2%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%
6	2%	2%	3%	3%	3%	3%	3%	1%	0%	1%	1%	1%	6	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%
7	3%	2%	2%	1%	1%	1%	1%	1%	0%	0%	1%	2%	7	-1%	-1%	-2%	-3%	-4%	-2%	-2%	-2%	-2%	-2%	-1%	-1%
8	1%	1%	1%	1%	0%	1%	1%	1%	1%	0%	0%	1%	8	-2%	-3%	-3%	-3%	-3%	-2%	-2%	-2%	-2%	-3%	-3%	-3%
9	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	9	-3%	-3%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-3%	-3%
10	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	10	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-2%	-2%
11	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	11	-2%	-1%	-1%	-1%	-1%	-2%	-1%	-2%	-1%	-1%	-1%	-2%
12	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	12	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
13	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	13	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
14	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	14	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	-1%	-1%
15	1%	1%	1%	1%	2%	2%	3%	2%	2%	2%	0%	0%	15	-1%	-1%	-1%	-1%	0%	0%	0%	0%	-1%	0%	0%	0%
16	1%	2%	1%	1%	2%	2%	3%	3%	3%	2%	1%	1%	16	-1%	-1%	-1%	-1%	-1%	0%	0%	-1%	-1%	0%	0%	0%
17	1%	2%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	17	-1%	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%	0%	0%	0%
18	1%	1%	2%	2%	2%	2%	2%	2%	1%	1%	1%	2%	18	0%	-1%	-1%	0%	0%	0%	-1%	-1%	-1%	0%	0%	0%
19	1%	1%	3%	4%	3%	4%	3%	3%	3%	3%	2%	2%	19	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	0%	0%	0%
20	4%	4%	3%	4%	3%	3%	2%	2%	1%	1%	4%	3%	20	0%	0%	-1%	-2%	-2%	-3%	-3%	-3%	-4%	-3%	0%	0%
21	1%	2%	2%	2%	1%	2%	2%	1%	1%	0%	1%	1%	21	-1%	-1%	-5%	-5%	-5%	-5%	-5%	-4%	-4%	-3%	-3%	-3%
22	0%	1%	1%	2%	1%	2%	2%	1%	1%	1%	0%	0%	22	-6%	-6%	-6%	-4%	-4%	-4%	-4%	-4%	-2%	-2%	-3%	-3%
23	1%	1%	1%	1%	1%	1%	2%	2%	1%	1%	0%	1%	23	-5%	-5%	-5%	-4%	-4%	-5%	-5%	-4%	-2%	-3%	-2%	-2%

FIGURE C-33: RETAIL STORES (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12	Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	2%	1%	0	-4%	-5%	-3%	-2%	-2%	-4%	-4%	-4%	-3%	-3%	-4%	-3%
1	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	1	-3%	-3%	-3%	-2%	-2%	-3%	-3%	-3%	-3%	-2%	-3%	-2%
2	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-3%	-3%	-3%	-2%
3	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	3	-2%	-2%	-2%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%
4	1%	0%	1%	1%	1%	2%	2%	1%	1%	1%	1%	1%	4	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%
5	1%	1%	2%	2%	2%	2%	2%	1%	1%	1%	1%	1%	5	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-1%	-2%	-1%
6	1%	2%	1%	1%	1%	1%	1%	1%	0%	0%	1%	1%	6	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-2%	-1%	-1%	-1%	-1%
7	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	1%	7	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%
8	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	8	-2%	-2%	-3%	-3%	-3%	-3%	-3%	-2%	-2%	-2%	-2%	-2%
9	1%	1%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	9	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-2%	-2%	-1%	-2%	-3%
10	1%	1%	0%	0%	1%	1%	1%	1%	1%	1%	0%	1%	10	-2%	-3%	-2%	-3%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-2%
11	1%	1%	1%	1%	1%	2%	2%	2%	1%	2%	1%	1%	11	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%
12	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	1%	1%	12	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
13	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	1%	1%	13	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
14	1%	1%	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	14	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
15	1%	1%	1%	1%	2%	2%	2%	3%	3%	2%	1%	1%	15	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
16	1%	1%	2%	2%	3%	4%	5%	5%	4%	4%	2%	2%	16	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
17	4%	3%	2%	2%	3%	3%	3%	4%	2%	3%	2%	2%	17	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	-1%
18	3%	4%	3%	3%	4%	4%	4%	4%	3%	2%	2%	2%	18	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-1%	-1%
19	4%	4%	4%	3%	3%	4%	4%	4%	4%	4%	2%	2%	19	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%
20	5%	6%	3%	2%	1%	1%	1%	2%	1%	1%	4%	4%	20	-2%	-2%	-2%	-3%	-4%	-5%	-5%	-5%	-4%	-3%	-2%	-1%
21	2%	3%	2%	1%	1%	2%	1%	1%	1%	1%	2%	2%	21	-4%	-5%	-4%	-4%	-3%	-5%	-6%	-7%	-5%	-5%	-3%	-3%
22	1%	1%	2%	2%	1%	2%	2%	2%	1%	1%	1%	1%	22	-7%	-8%	-4%	-2%	-2%	-3%	-4%	-4%	-2%	-4%	-4%	-4%
23	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	23	-4%	-3%	-4%	-3%	-3%	-6%	-7%	-7%	-6%	-6%	-2%	-3%

FIGURE C-34: SCHOOLS (PERCENT DISCHARGE/CHARGE KWH BY HOUR AND MONTH)

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%
1	0%	0%	1%	1%	2%	1%	1%	0%	0%	0%	1%	0%
2	0%	0%	1%	2%	2%	2%	1%	1%	0%	0%	1%	0%
3	0%	0%	1%	2%	3%	2%	2%	1%	0%	0%	1%	0%
4	1%	1%	2%	3%	4%	3%	3%	2%	1%	1%	1%	1%
5	1%	1%	2%	4%	4%	3%	3%	3%	2%	2%	1%	1%
6	2%	3%	3%	2%	2%	2%	2%	3%	2%	2%	2%	2%
7	4%	4%	2%	1%	1%	1%	1%	1%	1%	1%	2%	3%
8	2%	3%	1%	0%	0%	0%	0%	0%	0%	1%	1%	1%
9	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%
13	1%	1%	1%	0%	0%	0%	1%	1%	1%	1%	0%	0%
14	1%	1%	1%	0%	0%	0%	1%	1%	1%	1%	1%	0%
15	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	1%	1%
16	2%	2%	1%	1%	1%	1%	2%	2%	3%	3%	2%	2%
17	4%	3%	3%	2%	2%	2%	2%	4%	3%	4%	4%	4%
18	5%	5%	5%	5%	5%	4%	5%	5%	5%	4%	4%	4%
19	5%	6%	5%	5%	6%	5%	6%	5%	5%	4%	4%	4%
20	4%	5%	4%	4%	5%	4%	4%	4%	3%	4%	4%	4%
21	3%	4%	2%	2%	3%	3%	2%	2%	2%	2%	3%	3%
22	1%	1%	2%	4%	4%	3%	3%	3%	3%	3%	2%	1%
23	2%	2%	1%	1%	1%	1%	1%	0%	0%	0%	2%	2%

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
1	-1%	-1%	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
2	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	-1%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	-1%	-1%	-1%	0%	0%	0%	0%	0%
6	0%	0%	-1%	-3%	-4%	-3%	-3%	-2%	-2%	-1%	0%	0%
7	-1%	-2%	-4%	-8%	-10%	-7%	-6%	-5%	-4%	-4%	-3%	-1%
8	-4%	-6%	-8%	-12%	-13%	-10%	-10%	-8%	-7%	-6%	-7%	-4%
9	-9%	-9%	-10%	-11%	-11%	-10%	-10%	-9%	-8%	-8%	-10%	-8%
10	-11%	-11%	-9%	-7%	-7%	-7%	-7%	-7%	-7%	-8%	-9%	-10%
11	-10%	-10%	-6%	-4%	-3%	-4%	-4%	-5%	-4%	-6%	-6%	-8%
12	-7%	-6%	-4%	-2%	-2%	-3%	-2%	-3%	-2%	-3%	-3%	-5%
13	-3%	-3%	-2%	-2%	-1%	-2%	-1%	-2%	-1%	-1%	-1%	-3%
14	-1%	-1%	-2%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%
15	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-1%	-1%	-1%	-1%
16	0%	0%	-1%	0%	-1%	0%	-1%	-1%	-1%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	-1%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	0%	0%
21	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
22	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	0%
23	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	0%	0%