2018 SGIP ADVANCED 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 distributed generation (DG) and advanced energy storage (AES) technologies at customer homes and businesses. The SGIP is funded by California's electricity ratepayers and managed by Program Administrators (PAs) representing California's major investor owned utilities (IOUs). The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP.

The SGIP was originally designed to help reduce energy demand at IOU customer locations to address peak electricity problems in California. The program has evolved since 2001, with eligibility requirements, program administration and incentive levels all changing over time in response to California's evolving energy landscape. One key evolution is the contribution of advanced energy storage technologies within the SGIP. Through the end of 2019, the SGIP has a financial incentive allowance of over $500 million, with 80 percent of funds allocated to AES technologies. Furthermore, beginning in program year (PY) 2017, a first-come, first-served incentive system was replaced with a lottery. One prioritization of the lottery goes to storage projects paired with on-site renewable generation like solar.

The CPUC has developed a Measurement & Evaluation (M&E) plan which calls for a series of annual impact evaluations that are focused on AES technologies. The plan calls for several metrics to be reported for SGIP AES projects, including:

- Greenhouse gas (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.
- Quantify any contribution of energy storage projects to grid services where that storage substituted for and replaced planned investment into grid services.

The purpose of this study is to satisfy the requirements of the M&E plan for PY 2018 and assess the ability of AES 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 *PY 2017 SGIP Energy Storage Impact Evaluation Report*.[1] All projects that were included in the 2017 evaluation are included in this study, in addition to the projects that received incentive payments during 2018.

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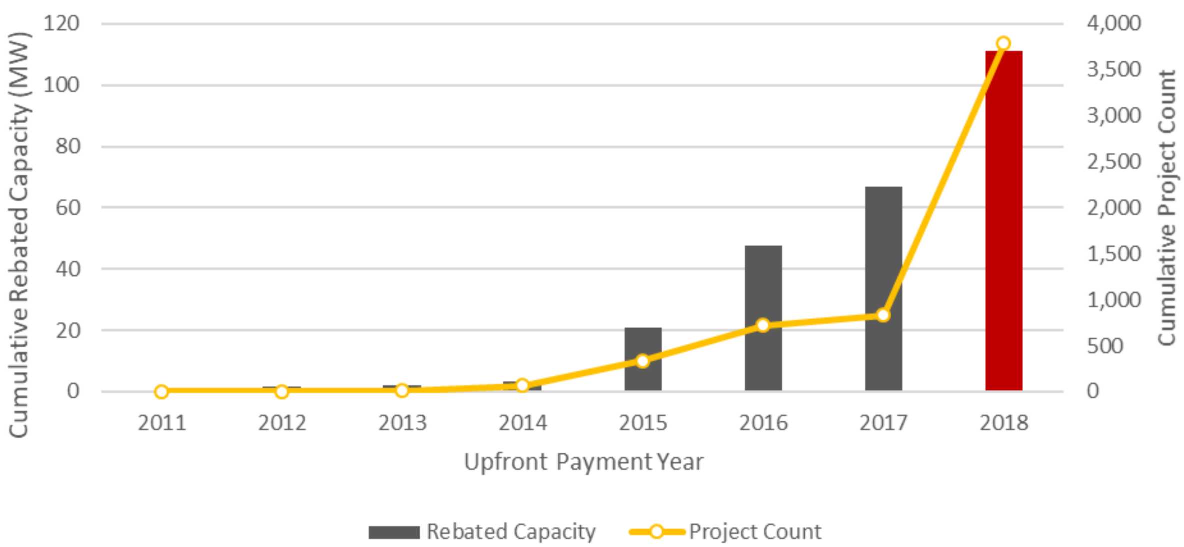
1 https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/2017_SGIP_AES_Impact_Evaluation.pdf

1.1 SCOPE OF REPORT

This evaluation is an assessment of energy storage projects that received an SGIP incentive on or before December 31, 2018. Figure 1-1 shows growth in SGIP energy storage rebated capacity[2] over time. By the end of 2018, the SGIP had provided incentives to 3,781 advanced energy storage projects representing almost 111 megawatts (MW) of rebated capacity. SGIP incentives are available for electrochemical, mechanical and thermal energy storage. As of December 31, 2018, all SGIP rebated storage projects were electrochemical (battery) energy storage technologies.

FIGURE 1-1: SGIP STORAGE CUMULATIVE GROWTH BY UPFRONT PAYMENT YEAR



The most significant growth in the SGIP from previous years has been in the residential sector. The number of residential storage projects subject to evaluation in 2018 has increased by roughly 700 percent, compared to the previous evaluation year. Performance-based incentive or PBI projects comprise the greatest percentage increase in program capacity. These systems are generally much larger than residential systems and their incentive is predicated on the performance of the system over a 5-year time period. Of the 111 MW of storage capacity in 2018:

- Nonresidential PBI projects represent 84 MW
- Residential systems represent 19 MW
- Nonresidential systems that are not PBI represent the remaining 8 MW

[2] As of PY 2017, rebated capacity is defined as the average discharge power rating over a two-hour period.

1.2 EVALUATION APPROACH

This evaluation study pursued two parallel paths to estimate SGIP storage program impacts:

- *What Actually Happened*? The evaluation team collected metered storage charge and discharge data and customer electric load profiles from residential and nonresidential SGIP participants. We then quantified how installation of the storage system changed the customer-specific energy and demand behavior relative to what would have happened in the absence of the storage system. If a storage system was discharging to service load at a home, it was likely reducing the power needed from the grid. This reduction in power, if conducted during a period when energy charges were high, could lead to bill savings for that customer. Furthermore, if that discharge also coincided with a period when the grid was congested – on a summer day when everyone is running their air conditioning – that reduction in demand from the grid could provide a benefit to the utility or result in a reduction in GHG emissions. This is the observed approach.
- *What Could Have Happened with Perfect Foresight*? The evaluation team conducted simulations on optimized storage charge and discharge for specific objectives. Given a customer's actual electric load profile, rate schedule and physical storage system characteristics as constraints, what could that customer have saved on their utility bill if they used their storage system optimally with perfect information? And what are the incremental costs to the utility or to GHG emissions under this perfectly optimal behavior? The simulated optimal dispatch was based on three different simulated approaches 1) storage used as described above, to minimize a customer's monthly electricity bill, 2) storage used to minimize the cost of serving power on the electric grid and 3) storage used to minimize GHG emissions. This is the optimization approach.

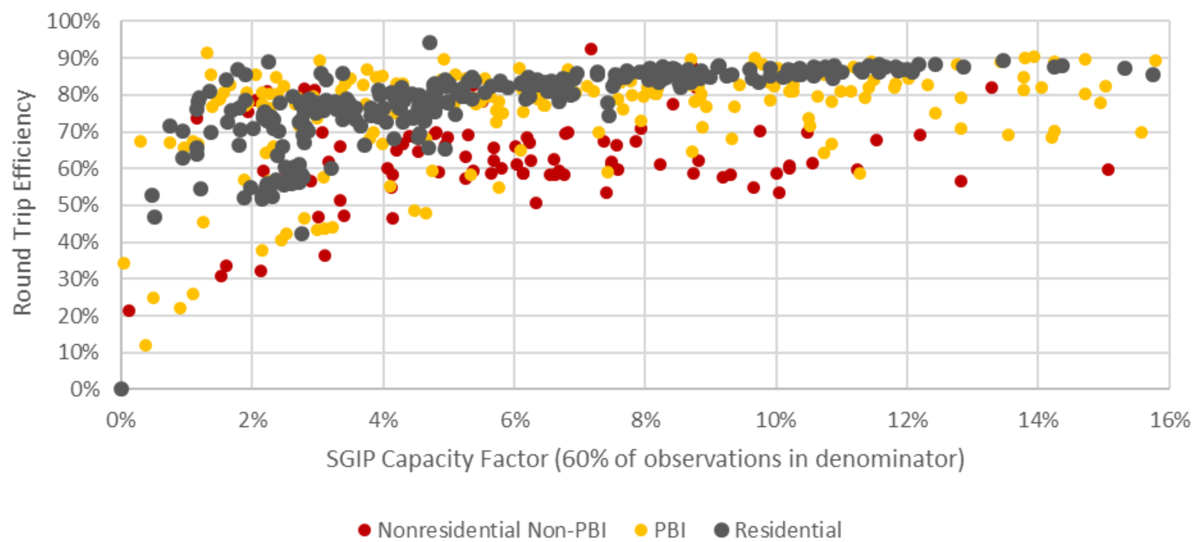
1.3 EVALUATION FINDINGS

These findings were developed based on observed and simulated analyses for a wide range of impacts. These impacts reveal how storage behavior in 2018 was meeting or falling short of SGIP goals and objectives. Below we present high level findings from this impact evaluation. In-depth findings and analyses can be found in Sections 4 and 5 of this report.

There is a strong relationship between storage system utilization and system efficiency. Two important AES performance metrics are roundtrip efficiency (RTE) and capacity factor (CF). 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 CF is a measure of utilization – how often is the system being discharged to perform different objectives. The two are related – if a system is not being utilized then it remains idle and consumes energy (or losses). 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 efficiency or RTE of the system.

This relationship is evident in Figure 1-2 where each of the evaluated project CFs and RTEs are plotted for different customer sectors. Generally, as capacity factor or utilization increases (horizontal axis) so does the efficiency or RTE (vertical axis). The average capacity factor for nonresidential non-PBI systems was 4.4 percent, 6.4 percent for PBI systems and 5.8 percent for residential systems. The average RTE for nonresidential non-PBI systems was 62 percent, 81 percent for PBI systems and 78 percent for residential systems.

FIGURE 1-2: OBSERVED ROUNDTRIP EFFICIENCY VERSUS CAPACITY FACTORS BY CUSTOMER SECTOR



Energy storage systems are used to deliver bill savings. One of the key influences on storage utilization and efficiency is how the system is being managed to provide customer benefits. Customer objectives are based on a range of factors including:

- the amount of energy the home or facility uses and at what time of day and year they use it
- what rate schedule the customer is on and how their bill impacts are assessed
- whether they generate their own electricity from on-site generation, such as a fuel cell or solar

A residential customer who is assessed energy charges that vary based on the time of day and a commercial customer, who is assessed a demand charge for the amount of power they use at a given period throughout the month, will likely utilize their storage systems in different ways in order to maximize their individual benefit. These differing use cases have a significant impact on how the system is utilized and, by extension, how the system affects other potential societal and SGIP objectives like reducing GHG emissions or providing relief to the grid during periods of high demand.

The range of use cases for storage in the SGIP will impact how the system is utilized throughout the year and the timing and duration of charge and discharge. Below we present the average hourly net charge (red) or discharge (green) for each month and hour throughout the year for the three customer sectors.

PBI systems are discharging for long durations throughout peak periods, charging overnight and customers are saving money on their electricity bill. PBI systems – sized 30 kilowatt (kW) or greater – exhibit a clear signature of charge and discharge behavior. They are discharging most prominently in the early/later afternoon hours especially during summer months and the latter part of the year and, given their relative size, are discharging for long durations (sometimes 4-5 hours). Systems also don't always charge immediately after the storage system has discharged. They remain idle and charge overnight, which coincides with periods when retail electricity rates and overall system demand are lower. Furthermore, *these customers are saving money on their bills* as a result. While they are often discharging energy outside of their bill peak period (when retail electricity rates are highest), they are consistently reducing their peak demand. While they incur costs for the increase in energy usage, they are saving significantly more on the demand charge portion of their bill.

	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	-0.125	-0.115	-0.106	-0.095	-0.090	-0.076	-0.115	-0.104	-0.065	-0.093	-0.130	-0.122
1	-0.098	-0.095	-0.079	-0.063	-0.057	-0.026	-0.069	-0.056	-0.040	-0.068	-0.104	-0.089
2	-0.071	-0.068	-0.046	-0.031	-0.037	-0.020	-0.042	-0.030	-0.026	-0.045	-0.076	-0.068
3	-0.040	-0.038	-0.024	-0.015	-0.020	-0.014	-0.026	-0.033	-0.027	-0.032	-0.059	-0.062
4	-0.021	-0.022	-0.023	-0.023	-0.023	-0.028	-0.048	-0.025	-0.024	-0.023	-0.039	-0.045
5	-0.032	-0.029	-0.013	-0.008	-0.007	-0.007	-0.005	-0.009	-0.010	-0.007	-0.019	-0.026
6	0.000	0.007	0.005	0.001	0.004	-0.003	-0.001	0.004	0.005	0.006	0.004	0.003
7	0.005	0.004	0.002	0.003	0.006	-0.003	-0.014	-0.006	-0.004	-0.010	-0.002	0.007
8	-0.004	-0.010	-0.006	0.002	0.003	-0.008	-0.029	-0.019	-0.021	-0.033	-0.027	-0.022
9	-0.004	-0.008	0.000	0.008	0.005	0.000	-0.016	-0.013	-0.017	-0.025	-0.031	-0.040
10	0.003	0.003	0.005	0.007	0.007	0.008	0.000	-0.001	-0.008	-0.015	-0.025	-0.037
11	0.013	0.011	0.013	0.017	0.016	0.017	0.018	0.021	0.012	0.010	-0.010	-0.025
12	0.024	0.023	0.022	0.022	0.019	0.022	0.025	0.023	0.019	0.023	0.010	-0.006
13	0.029	0.025	0.022	0.017	0.021	0.019	0.048	0.037	0.017	0.019	0.016	0.003
14	0.015	0.016	0.016	0.012	0.019	0.021	0.058	0.039	0.015	0.034	0.021	0.006
15	0.008	0.012	0.021	0.026	0.039	0.043	0.084	0.066	0.042	0.072	0.051	0.047
16	0.020	0.019	0.022	0.020	0.029	0.031	0.081	0.060	0.038	0.080	0.086	0.072
17	0.032	0.035	0.031	0.022	0.005	-0.004	0.003	-0.005	0.009	0.023	0.089	0.078
18	0.036	0.035	0.053	0.053	0.034	0.012	0.023	0.021	0.025	0.045	0.031	0.032
19	0.054	0.048	0.057	0.051	0.044	0.019	0.032	0.033	0.025	0.049	0.046	0.047
20	0.056	0.050	0.004	-0.021	-0.004	-0.018	-0.005	-0.004	-0.002	-0.014	0.041	0.050
21	-0.016	-0.014	-0.046	-0.061	-0.057	-0.038	-0.011	-0.020	-0.014	-0.043	-0.009	0.007
22	-0.077	-0.073	-0.084	-0.098	-0.117	-0.099	-0.144	-0.144	-0.113	-0.121	-0.036	-0.024
23	-0.092	-0.086	-0.112	-0.125	-0.130	-0.091	-0.143	-0.147	-0.115	-0.135	-0.123	-0.107

Non-PBI nonresidential systems are discharging for shorter durations than PBI projects, are charging immediately following discharge and are saving customers money on their electricity bill. Non-PBI nonresidential systems exhibit a different pattern of charge/discharge behavior. These systems are net charging throughout most of the year and, more specifically, throughout their peak periods. However, *these systems are saving customers money on their bills* as well. Like the larger PBI systems, they increase the energy portion of the bill, but they are reducing overall demand and saving money on the demand portion of the bill. These systems are designed to reduce demand when load begins to increase. Because of the design of the systems or their size relative to the facility load, they are discharging for a shorter duration than PBI projects, on average. They will often charge immediately after a discharge event in preparation for another potential peak in facility load.

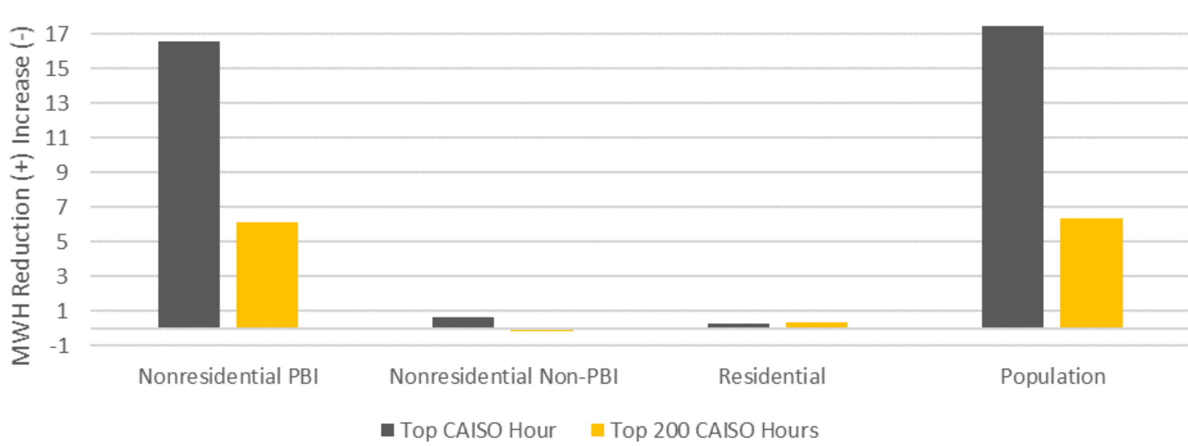
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.022	-0.019	-0.012	-0.013	0.008	0.061	0.050	0.025	-0.014	-0.009	-0.017	0.005
1	-0.020	-0.016	-0.013	-0.015	-0.029	-0.058	-0.006	0.064	0.057	-0.050	-0.019	-0.011
2	-0.020	-0.017	-0.010	-0.012	-0.024	-0.061	-0.129	-0.101	-0.068	-0.027	-0.010	-0.042
3	-0.017	-0.014	-0.010	-0.012	-0.020	-0.028	-0.049	-0.103	-0.103	-0.090	-0.065	-0.098
4	-0.014	-0.013	-0.004	-0.003	-0.016	-0.023	-0.023	-0.043	-0.075	-0.065	-0.045	-0.068
5	-0.003	-0.008	-0.003	0.016	0.024	0.009	0.011	0.011	-0.010	0.000	-0.010	-0.032
6	-0.003	-0.004	-0.008	0.007	0.022	0.008	0.006	0.018	0.004	0.011	-0.003	-0.019
7	-0.020	-0.013	-0.009	-0.005	-0.002	0.001	-0.001	-0.003	-0.009	-0.006	-0.011	-0.017
8	-0.007	-0.011	-0.007	-0.009	-0.012	-0.006	-0.009	-0.011	-0.012	-0.013	-0.014	-0.013
9	-0.016	-0.011	-0.004	-0.015	-0.025	-0.019	-0.012	-0.023	-0.023	-0.024	-0.026	-0.027
10	-0.009	-0.011	-0.007	-0.019	-0.031	-0.020	-0.013	-0.028	-0.035	-0.034	-0.029	-0.030
11	-0.020	-0.015	-0.005	-0.020	-0.029	-0.022	-0.020	-0.030	-0.036	-0.035	-0.030	-0.031
12	-0.017	-0.012	-0.007	-0.021	-0.034	-0.020	-0.011	-0.030	-0.035	-0.034	-0.025	-0.032
13	-0.018	-0.009	-0.008	-0.019	-0.031	-0.027	-0.018	-0.035	-0.040	-0.035	-0.026	-0.031
14	-0.016	-0.017	-0.010	-0.026	-0.041	-0.031	-0.026	-0.032	-0.036	-0.043	-0.033	-0.030
15	-0.029	-0.021	-0.003	-0.011	-0.009	-0.001	-0.008	-0.002	-0.007	-0.013	-0.018	-0.025
16	-0.013	-0.004	-0.003	-0.013	-0.018	-0.016	-0.014	-0.009	-0.014	-0.020	-0.013	-0.005
17	-0.007	-0.014	-0.012	-0.023	-0.031	-0.026	-0.049	-0.039	-0.039	-0.028	-0.013	-0.009
18	-0.015	-0.022	-0.012	-0.019	-0.032	-0.042	-0.058	-0.043	-0.023	-0.002	-0.024	-0.023
19	-0.023	-0.020	-0.010	-0.017	-0.024	-0.029	-0.036	-0.027	-0.032	-0.024	0.000	0.010
20	-0.024	-0.021	-0.023	-0.026	-0.033	-0.039	-0.042	-0.030	-0.026	-0.028	-0.020	-0.017
21	-0.029	-0.025	-0.028	-0.022	-0.040	-0.040	-0.028	-0.042	-0.023	-0.019	-0.042	-0.047
22	-0.031	-0.027	-0.018	-0.019	-0.034	-0.028	-0.058	-0.037	-0.040	-0.044	-0.026	-0.021
23	-0.026	-0.025	-0.017	-0.016	-0.022	-0.017	-0.028	-0.032	-0.019	-0.005	-0.025	-0.017

Residential storage systems are charging almost exclusively from on-site solar production, are discharging during peak periods and are saving customers money on their electricity bill. Residential storage systems exhibit a very different pattern of charge and discharge throughout the year than nonresidential systems. These systems are often paired with on-site solar, so the storage system can bypass charging directly from the grid and utilize solar power to charge the system. Charging throughout the summer and latter part of the year comes almost exclusively in the early morning hours, when solar production is ramping up. Residential customers are not subject to demand charges and most customers are on a time-of-use (TOU) schedule.

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	0.011	0.027	0.018	0.019	0.026	0.021	0.012	0.021	0.021	0.017	0.009	0.004
1	0.004	0.013	0.015	0.022	0.019	0.015	0.007	0.013	0.013	0.011	0.004	0.000
2	-0.001	0.007	0.012	0.016	0.014	0.013	0.005	0.008	0.010	0.010	0.003	0.001
3	-0.001	0.005	0.009	0.015	0.013	0.012	0.004	0.007	0.009	0.009	0.003	0.001
4	-0.002	0.004	0.009	0.015	0.013	0.013	0.004	0.007	0.009	0.009	0.002	0.001
5	-0.002	0.003	0.011	0.017	0.013	0.010	0.005	0.008	0.011	0.011	0.003	0.001
6	-0.001	0.003	0.007	0.000	-0.008	-0.015	-0.011	-0.009	-0.001	0.004	0.002	0.001
7	-0.003	-0.004	-0.022	-0.052	-0.057	-0.078	-0.054	-0.062	-0.050	-0.036	-0.023	-0.009
8	-0.021	-0.047	-0.072	-0.127	-0.122	-0.158	-0.125	-0.148	-0.137	-0.110	-0.079	-0.050
9	-0.057	-0.099	-0.116	-0.172	-0.161	-0.221	-0.199	-0.231	-0.229	-0.184	-0.140	-0.111
10	-0.087	-0.125	-0.125	-0.154	-0.152	-0.200	-0.206	-0.245	-0.253	-0.198	-0.160	-0.142
11	0.028	-0.009	-0.026	-0.036	-0.053	-0.080	-0.103	-0.157	-0.175	-0.143	-0.120	-0.118
12	0.044	0.009	-0.003	0.003	-0.016	-0.023	-0.038	-0.084	-0.098	-0.093	-0.083	-0.089
13	-0.067	-0.098	-0.078	-0.060	-0.063	-0.030	-0.038	-0.047	-0.055	-0.056	-0.062	-0.071
14	-0.103	-0.133	-0.105	-0.086	-0.080	-0.007	0.002	0.002	0.011	0.020	0.028	0.022
15	-0.078	-0.106	-0.087	-0.072	-0.064	0.000	0.012	0.028	0.040	0.040	0.036	0.037
16	0.018	-0.008	-0.006	0.014	0.019	0.116	0.140	0.157	0.161	0.087	0.081	0.075
17	0.037	0.051	0.038	0.047	0.052	0.095	0.112	0.135	0.136	0.106	0.089	0.086
18	0.023	0.064	0.063	0.074	0.079	0.066	0.072	0.106	0.105	0.092	0.075	0.070
19	0.000	0.038	0.051	0.076	0.079	0.056	0.056	0.088	0.084	0.069	0.055	0.047
20	0.004	0.039	0.047	0.065	0.065	0.049	0.046	0.070	0.063	0.052	0.043	0.035
21	-0.001	0.034	0.037	0.047	0.049	0.041	0.036	0.048	0.044	0.041	0.031	0.023
22	-0.004	0.027	0.031	0.042	0.046	0.025	0.022	0.030	0.030	0.030	0.023	0.016
23	0.003	0.033	0.027	0.028	0.035	0.024	0.018	0.026	0.027	0.024	0.014	0.006

All customer sectors are providing a benefit to the electricity system during the peak hour and PBI and residential systems maintain that benefit across the top 200 peak system hours. The timing and duration of storage charge and discharge throughout the year is also important from the perspective of the entire CAISO system. Peak periods often coincide with periods when the electricity system is congested and would benefit from reductions in demand. Figure 1-3 presents how all three customer sectors provide a benefit to the CAISO system during its peak hour in 2018 by discharging more energy throughout that hour than they were charging. As mentioned above, residential and nonresidential PBI systems are discharging for long durations and, as a result, capturing reductions throughout other peak hours. SGIP projects net discharged roughly 17.5 megawatt hours (MWh) of energy during the top hour and averaged almost 6.5 MWh of energy discharged per hour across the top 200 hours.

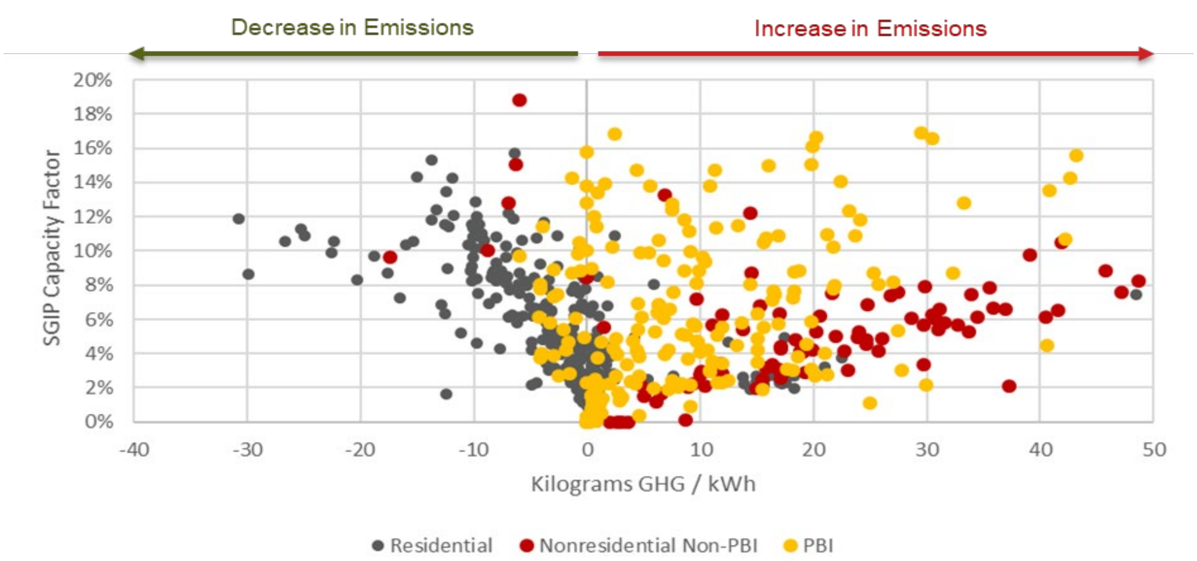
FIGURE 1-3: OBSERVED NET DISCHARGE (MWH) DURING CAISO SYSTEM PEAK HOURS BY CUSTOMER SECTOR



The timing, magnitude and duration of storage charge and discharge behavior provided a benefit or avoided cost to the utilities in 2018. The 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. PBI and residential systems were discharging throughout these highly constrained hours. Overall, the patterns of storage charge and discharge throughout 2018 resulted in a roughly $2.2 million benefit in avoided costs to the utilities.

Nonresidential projects contributed to a net increase in GHG and residential projects reduced GHG emissions. For storage projects to reduce GHG emissions, the GHGs avoided during storage discharge must be greater than the GHG increase during storage charging. Since these technologies inherently consume more energy during charging relative to energy discharged, the marginal emissions rate must be lower during charging hours relative to discharge hours. Figure 1-4 plots the decrease or increase in emissions for each project (horizontal axis) against the capacity factor or utilization of the system (vertical axis). Residential systems are plotted in gray and 68 percent of all systems reduced emissions. Furthermore, there's a strong relationship between utilization and magnitude of emission reductions. However, the opposite is true for nonresidential systems – especially non-PBI ones. During 2018, nonresidential SGIP AES projects increased GHG emissions by 1,517 metric tons (MT). Residential projects reduced emissions by roughly 70 metric tons (70,000 kilograms).

FIGURE 1-4: OBSERVED GREENHOUSE GAS EMISSIONS AND CAPACITY FACTOR BY CUSTOMER SECTOR



Simulating storage dispatch to purely maximize customer bill savings yields similar results to the observed or actual impacts for nonresidential customers, but less so for residential customers. For nonresidential customers the simulated bill savings, system cost savings and GHG impacts are roughly 20 - 50 percent higher under the optimal customer bill dispatch approach compared to estimates based on the observed charge and discharge profiles. This suggests that while nonresidential customers utilized their storage assets to realize significant bill savings in 2018, there was still potential to achieve annual bill savings as high as 150 $ / kW-rebated capacity through more optimal charging and discharging. Doing so would have resulted in an increase in system cost savings of $800,000, but also an increase in system GHG emissions by almost 400 metric tons in 2018. For residential customers, optimizing dispatch to minimize customer bills gives quite different charge and discharge patterns than what actually occurred. Consequently, simulated bill savings would have been much higher as would system savings. Most notably there would have been a substantial increase in system GHG emissions compared to the actual performance.

Under simulated dispatch, when residential customers were forced to charge 100 percent from solar, it led to a significant improvement in GHG impacts relative to maximizing bill savings. The observed impact analysis showed residential customers were charging almost exclusively from solar. This was likely driven by the Investment Tax Credit (ITC) requirements and customer desire to maximize on-site solar consumption. To further understand the implications of solar-only charging behavior on GHG emissions, the team conducted a simulation of optimized customer bill savings but included the solar-only charging constraint. Including this constraint shifted residential customers from increasing GHG emissions by 330 MT in 2018 to decreasing emissions by 72 MT. This emission reduction is similar to the actual impacts. This indicates that meeting ITC requirements may be a more effective incentive to reduce GHG emissions than trying to maximize bill savings.

Had the GHG cap requirements outlined in CPUC Decision (D.) 19-08-001 been placed on the nonresidential PBI fleet in 2018, all customers could have met the GHG cap with very minor impacts on annual bill savings. To understand the effect of the recent CPUC decision directing SGIP storage projects to reduce GHG emissions by at least 5 kilograms (kg) per rebated kilowatt hour (kWh), we performed simulations applying this new rule to all nonresidential PBI projects that began operations prior to 1/1/2018. Following the decision, we applied a penalty of $1/kg for every kg of GHGs an AES project was short of the cap.

- Under customer bill dispatch approach without this penalty, only 15 percent of projects met the 5 kg / kWh-rebated cap
- When optimized under the carbon dispatch approach, this rose to 83 percent of projects meeting the cap, with many projects exceeding the cap by a significant margin
- When optimized to maximize bill savings *and* at least meet the cap (Carbon Cap approach), then all projects would have met or exceeded the cap, but by a less significant margin than the carbon dispatch approach

With a GHG dispatch signal, customers can alter storage dispatch to provide increased GHG emission reductions without material bill impacts – assuming perfect foresight. A new approach, using a carbon price to co-optimize dispatch with the customer's retail rate and a carbon price adder, was used to quantify potential GHG emission reductions in 2018. AES dispatch is co-optimized to minimize both the customer bill and a carbon price adder, reducing GHG emissions with minimal or no impact on the customer's bill. For example, within a given bill TOU period where the customer's rate is the same, a given kWh quantity of AES discharge can be modified to increase GHG savings without any impact to the customer bill. With this approach, nonresidential AES projects go from increasing GHG emissions by nearly 2,000 MT under customer bill dispatch to reducing GHG emissions by 4,000 MT. Furthermore, there is little impact on customer bill savings. For residential storage systems, GHG emissions change from an increase of 328 to a decrease of 1,344 MT.

Moving customers onto the most dynamic tariffs currently available would generally improve system and emission impacts substantially for SDG&E and SCE customers, but less significant differences were seen for PG&E customers. While TOU rates capture general variations in utility system costs, more granularity is needed to truly capture the hourly fluctuations in system costs and GHG emissions. We therefore conducted a sensitivity in which we assigned each nonresidential customer to a more dynamic rate option offered by their utility. We considered PG&E's Peak Day Pricing add-on, SCE's Real-Time-Pricing rates, and SDG&E's Grid Integration Rate. Each customer was modeled with their more dynamic rate option under a customer bill dispatch approach, and these results were compared with the original dispatch using their actual rates. The results showed that the more dynamic rate options increased each utility's average system cost savings. For the two hourly dynamic rates (SCE and SDG&E), GHG emissions were substantially lower and the system cost savings more than doubled relative to the default TOU rate. The event-based PG&E Peak Day Pricing rate that is limited to 15 calls per summer did not reduce GHG emissions and increased system cost savings by only 25 percent. These results show that hourly dynamic rates can realize significant GHG emission and system cost benefits relative to TOU and event-based rate designs.

1.4 CONCLUSIONS AND CONSIDERATIONS

The nonresidential results of this evaluation are largely consistent with observations from the 2017 SGIP AES evaluation. However, residential results have changed dramatically, with the population of residential projects seeing significant growth since the last evaluation year (700 percent increase), and more sophisticated use cases being employed for AES technologies. Below we present key takeaways and conclusions from this 2018 SGIP AES impact evaluation. Where possible, the evaluation team also provides considerations and recommendations.

Rate design considerations for the nonresidential sector. SGIP storage projects consistently provide benefits to nonresidential customers in the form of billed demand savings. Large PBI projects provide significant demand reductions during CAISO top hours, but smaller non-PBI projects do not. However, both system types lead to increases in GHG emissions. Ideal dispatch modeling points to a similar conclusion. These results demonstrate that, under current retail rates, the incentives for nonresidential customers to dispatch AES to minimize bills are not well aligned with the goals of minimizing GHG emissions. Our modeling has shown that more dynamic rates that better align customer and grid benefits could provide substantial ratepayer and environmental benefits that are currently unrealized.

Charging from on-site solar generation. The evaluation team observed an overall decrease in GHG emissions from residential projects. These systems were almost exclusively charging during solar generation hours early in the morning – when marginal emissions are generally low. Ideal dispatch found, however, that residential projects would increase GHG emissions if optimally dispatched to minimize bills. Bill impact optimization would lead some customers to charge outside of solar generation hours when TOU rates may be lower. Customers should continue to be motivated to charge their storage systems during PV generation hours. Utilities could also benefit if they understood the timing and location of these charge events for the fleet of projects to provide reverse power-flow consistency and grid stabilization. Furthermore, if the timing of charging during PV generation hours doesn't matter (i.e., a customer is consistently exporting to the grid throughout the day and energy rates are the same at 8 am compared to 10 am), then shifting charge events throughout that PV generation window to follow lower marginal emissions periods, could provide an additional environmental benefit.

The timing and duration of charge and discharge patterns is far more important from a GHG reduction or avoided cost perspective than simply increasing storage utilization and roundtrip efficiency. There is a strong relationship between utilization (capacity factor) and RTE. We observe that the projects with the highest RTEs also tend to have the highest CFs. This in turn might suggest that if projects increased their annual capacity factor, the annual RTE would also increase. While this may be true, we find that even if all parasitic loads were removed leaving just the influence of single cycle RTE, average GHG emissions from nonresidential projects would remain positive. In other words, increasing capacity factor for the sake of increasing RTE alone will likely not turn SGIP nonresidential AES projects into net GHG reducers. A GHG signal like the one being implemented as a result of the SGIP GHG working group can help storage systems improve the timing and duration of charge/discharge. Our analysis shows that such a signal can be implemented to significantly reduce GHG emissions without a material impact on customer bills. Furthermore, the evaluation found that storage projects participating in demand response (DR) programs can reduce GHG emissions on days when events are called without any changes to storage utilization relative to non-event days.

2 INTRODUCTION AND OBJECTIVES

The Self-Generation Incentive Program (SGIP) was established legislatively in 2001 to help address peak electricity problems in California.[1] The SGIP is funded by California's electricity ratepayers and managed by Program Administrators (PAs) representing California's major investor owned utilities (IOUs).[2] 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. Beginning in Program Year (PY) 2009, advanced energy storage (AES) systems that met certain technical parameters and were coupled with eligible SGIP technologies (wind turbines and fuel cells) were eligible for incentives.[3] Eligibility requirements for AES projects changed during subsequent years, most significantly during PY 2011 when standalone AES projects (in addition to those paired with SGIP eligible technologies or PV) were made eligible for incentives.

On July 1, 2016 the CPUC issued Decision (D.) 16-06-055 revising the SGIP pursuant to Senate Bill 861, Assembly Bill 1478 and implementing other changes.[4] Among the changes was a revision to how the SGIP is administered. Beginning with PY 2017, the SGIP is now administered on a continuous basis and the incentive collections represent allocations through the end of 2019. 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 replaced the first-come, first-served reservation system with a lottery. Priority in the SGIP lottery process are given to:

- Energy storage projects located in the Los Angeles Department of Water and Power (LADWP) service territory
- Energy storage projects located in Southern California Edison's West LA Local Capacity Area
- Energy storage projects paired with on-site renewable generation that are claiming the Investment Tax Credit (ITC) or charging at least 75 percent from the on-site renewal generator

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[1] Assembly Bill 970, California Energy Security and Reliability Act of 2000 (Ducheny, September 6, 2000). The SGIP was established the following year as one of several programs to help address peak electricity problems.

[2] The Program Administrators are Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG) and the Center for Sustainable Energy (CSE), which implements the program for customers of San Diego Gas and Electric (SDG&E).

[3] https://www.sce.com/wps/wcm/connect/a48aaaa5-de53-48db-af1e-1775974e3e10/090617_2009SGIP Handbook.pdf?MOD=AJPERES

[4] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF

Most recently, the CPUC has issued several Decisions that, while not applicable to this current evaluation, will shape the program in years to come. On August 1, 2019 the CPUC issued Decision (D.) 19-08-001 approving greenhouse gas emission reduction requirements for the SGIP storage budget. This decision requires SGIP PAs to provide a digitally accessible greenhouse gas (GHG) signal that provides marginal GHG emissions factors (kg 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.[5] On September 12, 2019, the CPUC issued D. 19-09-027 establishing an SGIP equity resiliency budget, modifying existing equity budget incentives, and approving $10 million to support the San Joaquin Valley Disadvantaged Community Pilot Projects. To help deal with critical needs resulting from wildfire risks in the state, D. 19-09-027 establishes 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.[6]

The SGIP has authorized incentive collections totaling $501,735,000 through the end of 2019 and 80 percent of funds are allocated to energy storage technologies. Table 2-1 summarizes those authorized allocations by PA. The original incentive rate for AES projects was set at $2.00 / Watt in PY 2009. By PY 2018, the incentive levels for AES had changed and are predicated on system characteristics – large storage (>10 kW), large storage claiming ITC and residential storage (<= 10 kW) – and are divided across five steps. Incentives are now calculated on a watt-hour rather than watt basis and range from as high as $0.50/Watt-hour to $0.18/Watt-hour depending on a variety of conditions in each Program Administrator territory.

TABLE 2-1: STATEWIDE PROGRAM BUDGET AND ADMINISTRATOR ALLOCATIONS

Program Administrator	Authorized Incentive Collections
Pacific Gas and Electric	$217,620,000
Southern California Edison	$169,260,000
Center for Sustainable Energy	$66,495,000
Southern California Gas Company	$48,360,000

5 D. 19-08-001 made other changes including performance-based incentive payment penalties for nonresidential projects that fail to reduce GHG emissions.

6 Customers that meet the criteria for the Single Family Affordable Solar Homes (SASH) program, SASH for Disadvantaged Communities (DAC-SASH), the Solar on Multifamily Affordable Housing (SOMAH) program, and the Multifamily Affordable Solar Housing (MASH) program are eligible for participation in the SGIP equity budget.

2.1 REPORT PURPOSE AND PROGRAM STATUS

SGIP eligibility requirements and incentive levels have changed over time in alignment with California's evolving energy landscape. Annual impact evaluation reports serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet its goals.

The SGIP was originally designed to reduce energy use and demand at IOU customer locations. By 2007, growing concerns with potential air quality impacts prompted changes to the SGIP's eligibility rules. Approval of Assembly Bill (AB) 2778[7] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. Passage of Senate Bill (SB) 412[8] (Kehoe, October 11, 2009) refocused the SGIP toward GHG emission reductions.

D. 16-06-055 states that an SGIP M&E Plan should be developed by CPUC Energy Division (ED) staff in consultation with Program Administrators. On January 13, 2017, the CPUC ED submitted its plan to measure and evaluate the progress and impacts of the SGIP for Program Years 2016 – 2020. The CPUC M&E plan calls for the creation of a series of annual impact evaluations that are focused on energy storage. The plan calls for several metrics to be reported for SGIP energy storage projects, including:

- Net GHG emissions of AES systems as a class (i.e., all AES 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(l)(6), quantify any contribution of energy storage projects to grid services where that storage substituted for and replaced planned investment into grid services.

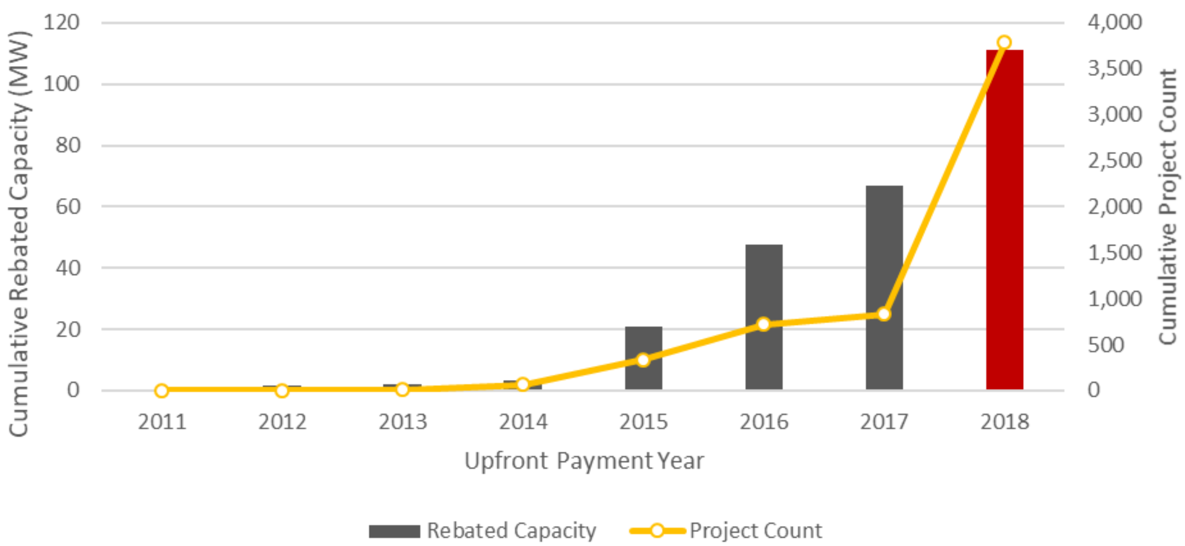
[7] http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

[8] http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

2.1.1 Scope

The scope of this impact evaluation includes but is not limited to the metrics discussed in Section 2.1. This evaluation is an assessment of energy storage projects that received an SGIP incentive on or before December 31, 2018. Figure 2-1 shows growth in SGIP energy storage rebated capacity[9] over time. By the end of 2018, the SGIP had provided incentives to 3,781 advanced energy storage projects representing almost 111 MW of rebated capacity. SGIP incentives are available for electrochemical, mechanical and thermal energy storage. As of December 31, 2018, all SGIP rebated storage projects were electrochemical (battery) energy storage technologies.

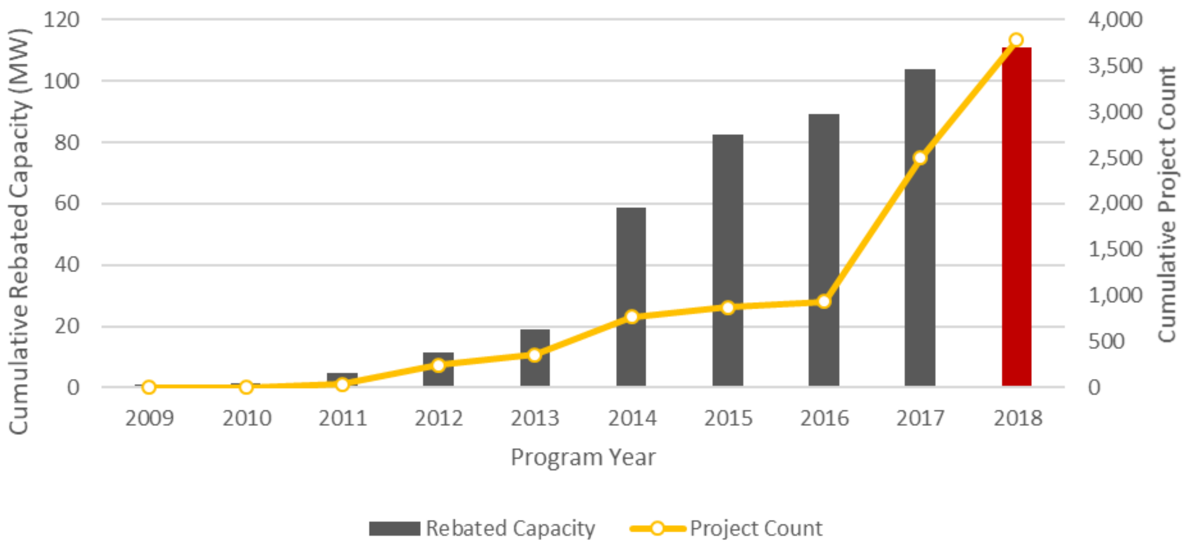
FIGURE 2-1: SGIP STORAGE CUMULATIVE GROWTH BY UPFRONT PAYMENT YEAR



While upfront payment year defines the scope of projects subject to evaluation for PY 2018, the upfront payment does not necessarily correspond to the program year in which the project applied to the SGIP. A project may apply to the SGIP in 2016, for example, but not receive their upfront payment until 2017. This is due to potential lag times between program application and the installation, interconnection and administrative timelines associated with building energy storage systems. Figure 2-2 shows growth in storage rebated capacity by program year (the year a project applied to the SGIP).

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

FIGURE 2-2: SGIP STORAGE CUMULATIVE GROWTH BY PROGRAM YEAR



From the perspective of rebated capacity, the SGIP storage program experienced the most significant growth during PY 2012 – 2015. However, by project count, the program experienced the most extensive growth during PY 2017 – 2018. The customer sector and policy timelines play a critical part in better understanding changes in the structure of the SGIP storage program. Figure 2-3 and Figure 2-4 highlight these nuances where the growth in the SGIP storage program for residential and nonresidential participants are presented, by project count and rebated capacity.

The SGIP saw a significant growth in program applications during PY 2017 -2018 because of the significant growth in residential projects. This dramatic increase is due, in part, to declining energy storage costs, new residential storage product offerings and an increase in the number of distinct project developers offering residential energy storage products. Nonresidential projects experienced the most significant growth during PY 2012 – 2015 after SB 412 had introduced Performance Based Incentive (PBI) payment rules to the SGIP and standalone energy storage became eligible for incentives. Nonresidential applications have leveled out by PY 2017, but the evaluated population has continued to grow, nonetheless, because upfront payments are being issued after applying to the program.

FIGURE 2-3: SGIP STORAGE CUMULATIVE PROJECT COUNT BY SECTOR AND PROGRAM YEAR

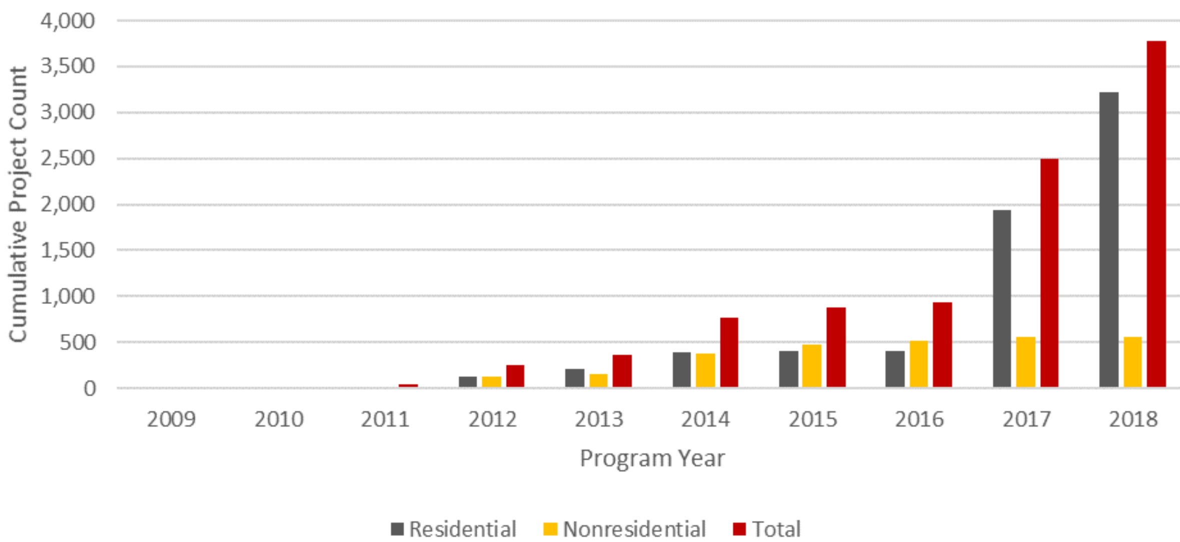


FIGURE 2-4: SGIP STORAGE CUMULATIVE REBATED CAPACITY BY SECTOR AND PROGRAM YEAR

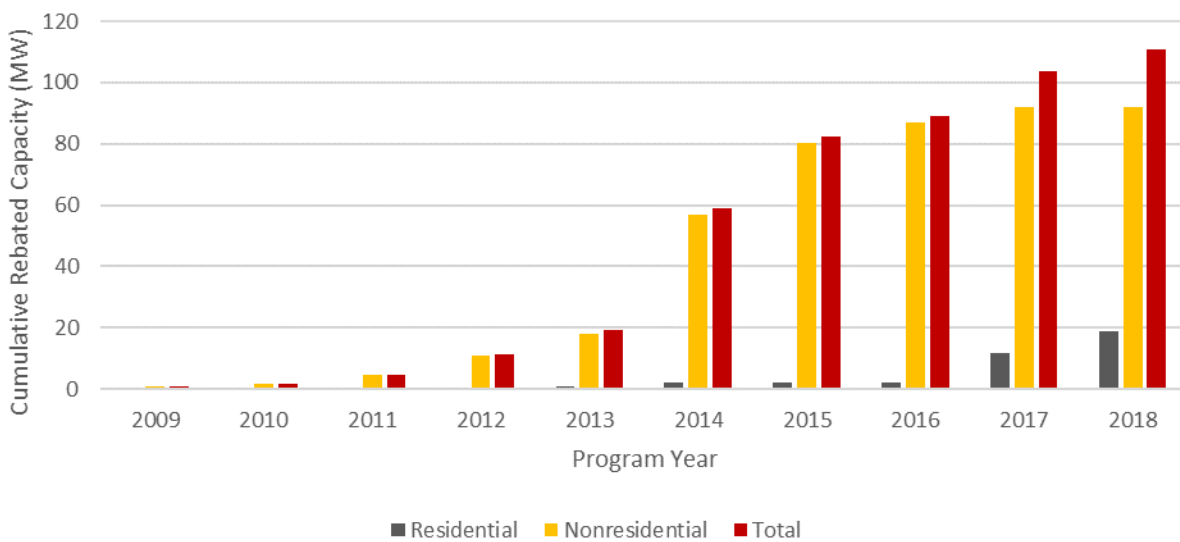


Table 2-2 summarizes the total number of projects, rebated capacity and incentive amounts reserved[10] by PA. PG&E administers the most energy storage projects, followed by SCE and CSE.

TABLE 2-2: ENERGY STORAGE PROJECT COUNTS AND REBATED CAPACITY BY PROGRAM ADMINISTRATOR

Program Administrator	Number of Projects	Rebated Capacity (kW)	Incentive Amount Reserved
Pacific Gas and Electric	1,675	36,489	$61,287,512
Southern California Edison	1,352	52,145	$81,715,601
Southern California Gas Company	118	2,407	$2,799,097
Center for Sustainable Energy	636	19,939	$30,636,480
Total	***3,781***	***110,980***	***$176,438,690***

SGIP storage projects are installed at locations where customers purchase electricity directly from electric or gas-IOUs and/or utilize the IOU distribution system to service load. When the PA is a gas-IOU the electric service may be provided by a municipal utility. Table 2-3 summarizes the number of projects and rebated capacity by PA and electric utility type. PG&E and SCG are the only PAs with energy storage projects installed at non-IOU electric customer locations. Overall, SGIP energy storage projects installed at electric-IOU customer locations represent roughly 96 percent of all installations.

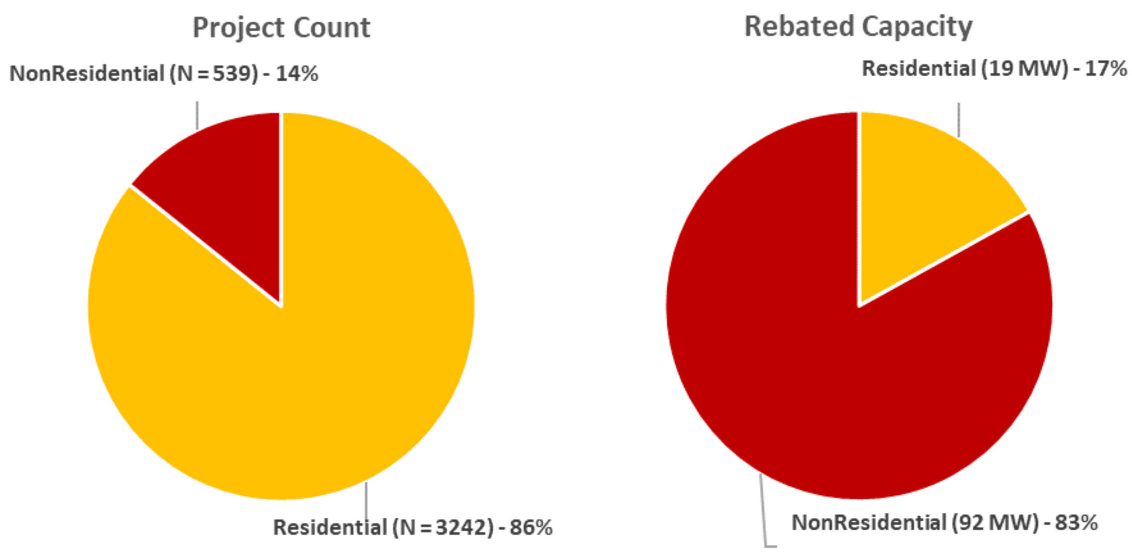
TABLE 2-3: ENERGY STORAGE PROJECT COUNTS AND REBATED CAPACITY BY PROGRAM ADMINISTRATOR AND ELECTRIC UTILITY TYPE

Program Administrator	Number of Projects		Rebated Capacity (kW)	
	IOU	Municipal	IOU	Municipal
Pacific Gas and Electric	1,634	41	36,259	230
Southern California Edison	1,352	-	52,145	-
Southern California Gas Company	18	100	1,764	643
Center for Sustainable Energy	636	-	19,939	-
Total	***3,640***	***141***	***110,107***	***873***

SGIP storage projects are installed at both residential and nonresidential customer sites and the growth in the number of projects applying to and receiving incentives from the SGIP has been substantial. Figure 2-5 shows the breakdown in sector by project count and rebated capacity. While the number of residential projects subject to evaluation in PY 2018 represents the vast majority by project count (86 percent), the majority of the SGIP storage rebated capacity (83 percent) continues to be installed at nonresidential customer sites. Nonresidential projects are almost always larger and therefore have a larger contribution to total program impacts.

[10] The incentive amount reserved is defined as the sum of the upfront incentive and any potential performance-based incentives reserved for a project.

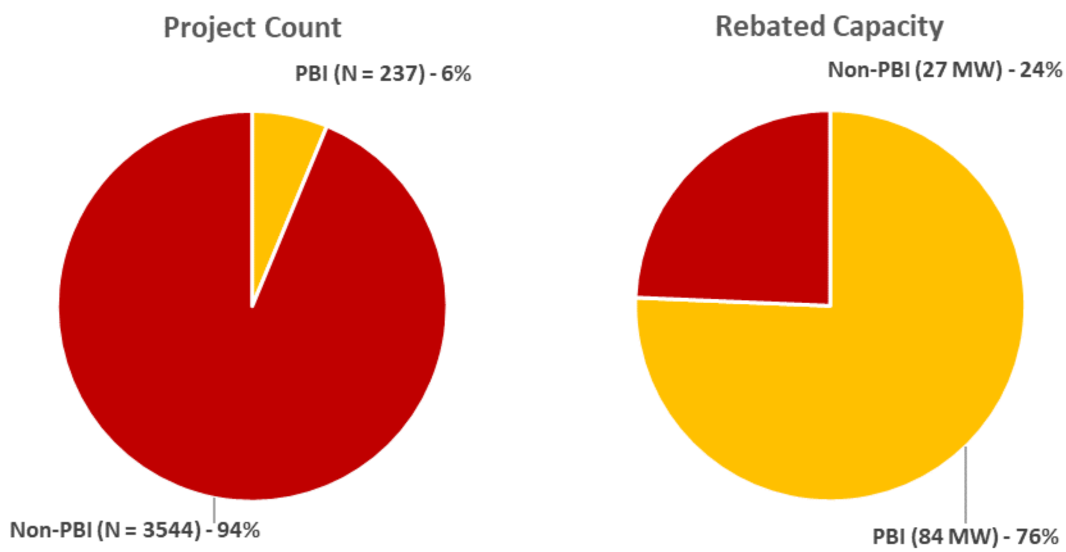
FIGURE 2-5: SGIP STORAGE PROJECT COUNT AND REBATED CAPACITY BY HOST CUSTOMER SECTOR



Projects are further split into two categories: 1) PBI[11] projects and 2) non-PBI projects. PBI projects are those with a rebated capacity equal to or greater than 30 kW that applied to the SGIP on or after PY 2011. All but two projects in the energy storage population were rebated on or after PY 2011 and therefore are subject to SB 412 provisions. There are 237 PBI projects in the SGIP population representing roughly 84 MW of the 111 MW total SGIP storage rebated capacity. All PBI projects are installed at nonresidential customer locations. Figure 2-6 summarizes the proportion of PBI and non-PBI projects in the SGIP population by project count and rebated capacity. Non-PBI projects represent the largest proportion of the population by project count, and PBI projects represent the largest proportion of the population by rebated capacity.

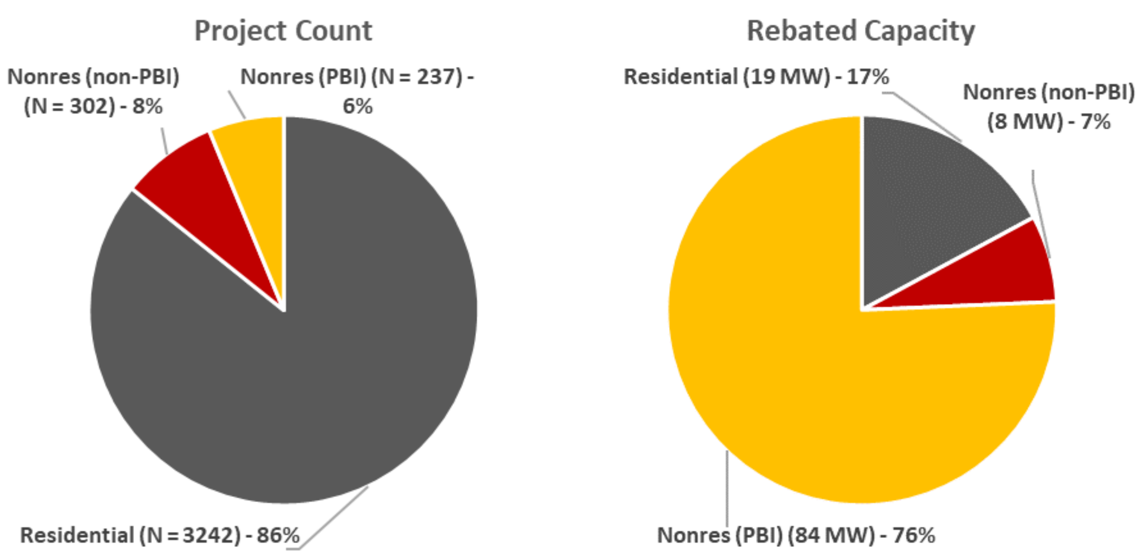
[11] *2016 Self-Generation Incentive Program Handbook*, 2016, available at https://www.selfgenca.com/home/resources/

FIGURE 2-6: SGIP STORAGE PROJECT COUNT AND REBATED CAPACITY BY PBI/NON-PBI CLASSIFICATION



Residential projects comprise the most significant percentage of non-PBI projects, both in terms of project count and rebated capacity. Figure 2-7 presents the distribution of projects and capacity by host customer sector as well as payment type (PBI versus non-PBI). Residential projects represent 86 percent of all projects and roughly 17 percent of total storage program capacity.

FIGURE 2-7: SGIP STORAGE PROJECT COUNT AND REBATED CAPACITY BY HOST CUSTOMER SECTOR AND PBI/NON-PBI CLASSIFICATION



Energy storage projects are installed at a variety of building types. Figure 2-8 summarizes the distribution of building types in the SGIP energy storage population by project count. Most energy storage projects in the population are installed in residential settings (3,242 of 3,781), followed by industrial facilities (124), hotels (102) and schools (85). However, residential energy storage projects are relatively small (approximately 6 kW rebated capacity on average) compared to nonresidential energy storage projects (approximately 150 kW rebated capacity each, on average).

FIGURE 2-8: DISTRIBUTION OF BUILDING TYPES WITH ENERGY STORAGE BY PROJECT COUNT

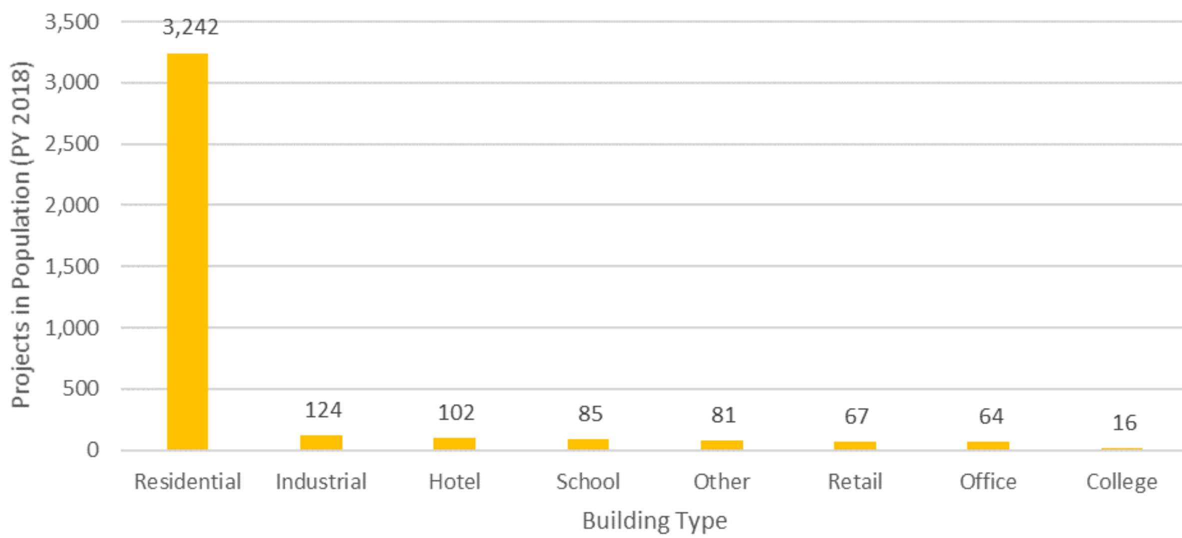
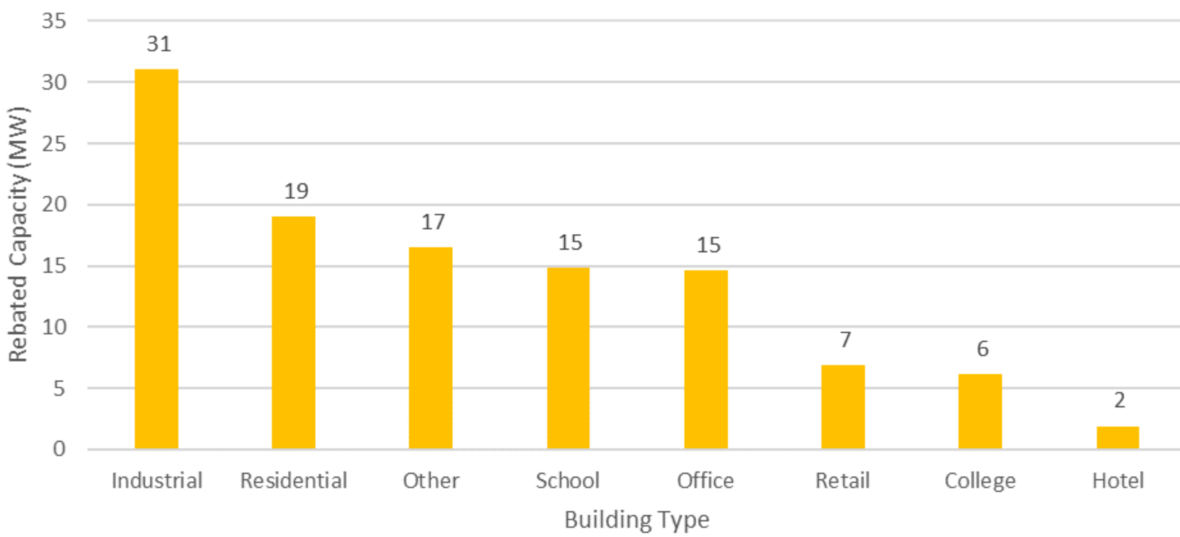


Figure 2-9 shows the distribution of SGIP project building types by rebated capacity. On a rebated capacity basis, the largest portion of the energy storage population is installed in the industrial sector. The 3,242 residential projects represent roughly 19 MW of rebated capacity. While hotels represent 102 total projects, their share (by rebated capacity) represents roughly 2 MW of installed rebated capacity.

FIGURE 2-9: DISTRIBUTION OF BUILDING TYPES WITH ENERGY STORAGE BY REBATED CAPACITY



2.1.2 Evaluation Period

This impact evaluation covers performance during the twelve-month period ending December 31, 2018. For projects that became operational during 2018, we estimate partial-year impacts based on the start of normal operations. Additional details on the evaluation methodology and approach are included in Section 4 and Appendix B.

2.2 METHODOLOGY OVERVIEW AND SOURCES OF DATA

This evaluation study pursued two parallel paths to quantifying SGIP storage program impacts:

- Estimation of observed program impacts based on metered data, and
- Quantification of simulated optimal dispatch behavior (i.e., assuming perfect foresight and maximum benefit provided to one value stream) to maximize customer, utility, or environmental benefits. This analysis is performed using Energy + Environmental Economics' (E3's) RESTORE Storage Dispatch Optimization model,[12] which minimizes customer bills, system costs or carbon emissions, depending on the given perspective being modeled.

Below we summarize the two approaches and their role in overall program impact evaluation.

[12] https://www.ethree.com/tools/restore-energy-storage-dispatch-model/

2.2.1 Overview of Observed Program Estimates Methodology

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. 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 utilities and project developers where available;
- Marginal emissions data and avoided cost information were provided by E3; and
- Additional information such as paired generator (PV, fuel cell, etc.) characteristics and participation in demand response (DR) programs 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 4. Details on the data integrity and quality control (QC) methods are provided in Appendix B.

2.2.2 Overview of Simulated Ideal Dispatch Behavior and Potential Program Impact Methodology

To quantify the potential benefits of energy storage if it were optimally dispatched with perfect foresight in 2018, we employ a short-term marginal cost approach using E3's RESTORE optimal dispatch model. RESTORE is populated with 2018 hourly system marginal cost values from the most recently published version of the E3 Distributed Energy Resource (DER) Avoided Cost Calculator. The Avoided Cost Calculator is used by the CPUC to evaluate costs and benefits of DERs, including energy efficiency, demand response and distributed generation. CPUC Decision 16-06-007 states that the SGIP program is to be evaluated using the most recently CPUC adopted avoided cost calculator.[13]

The RESTORE analysis aims to quantify the *maximum* benefits SGIP storage projects could have potentially achieved in 2018, *assuming they were optimally dispatched* for different objectives with perfect information. To understand how storage could be dispatched differently to achieve different outcomes, we optimally dispatch SGIP AES projects based on one of three dispatch approaches:

- For the Customer Bill Dispatch Approach, storage is dispatched to minimize a customer's monthly electricity bill;
- For the System Cost Dispatch Approach, storage is dispatched to minimize the marginal cost of serving load at the system level; and
- For the Carbon Dispatch Approach, storage is dispatched to minimize both the customer's monthly electricity bill and marginal carbon dioxide emissions.

Additional detail on this methodology is provided in Section 5.2.

2.3 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 population and details the sampling approach used to develop population impacts.
- Section 4 characterizes the metered sample and presents the observed program impacts.
- Section 5 summarizes potential storage benefits in the short-term using ideal dispatch simulations.
- Appendix A describes the marginal GHG emission calculation methodology.
- 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.

[13] See CPUC D. 16-06-007 available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K338/163338441.PDF

3 POPULATION AND SAMPLE CHARACTERIZATION

This section of the report presents the population of SGIP advanced energy storage (AES) projects subject to evaluation in this study and describes the sample of projects the evaluation team analyzed to satisfy the impact evaluation objectives detailed in Section 2.

3.1 SGIP 2018 POPULATION OF AES PROJECTS

As presented in Section 2, by the end of 2018, the SGIP provided incentives for 3,781 AES projects representing roughly 111 MW of rebated capacity. Figure 3-1 and Figure 3-2 present the change in SGIP rebated capacity and project count from the prior evaluation year by sector (residential versus nonresidential) and incentive payment mechanism (5-year PBI versus 100 percent upfront payment). The SGIP added roughly 44 MW of rebated capacity and over 2,900 projects received upfront payments during 2018. This represents a total net increase in total capacity of 66 percent and a 356 percent increase in total projects.

The most significant percentage increase in project counts and rebated capacity comes from residential projects, at 799 percent and 697 percent, respectively. Nonresidential PBI projects represent the most significant increase in total SGIP rebated capacity (roughly 21 MW) and population level nonresidential non-PBI project capacity has also increased by roughly 7 percent.

FIGURE 3-1: SGIP STORAGE CHANGE IN REBATED CAPACITY FROM 2017 TO 2018 BY SECTOR AND PAYMENT TYPE

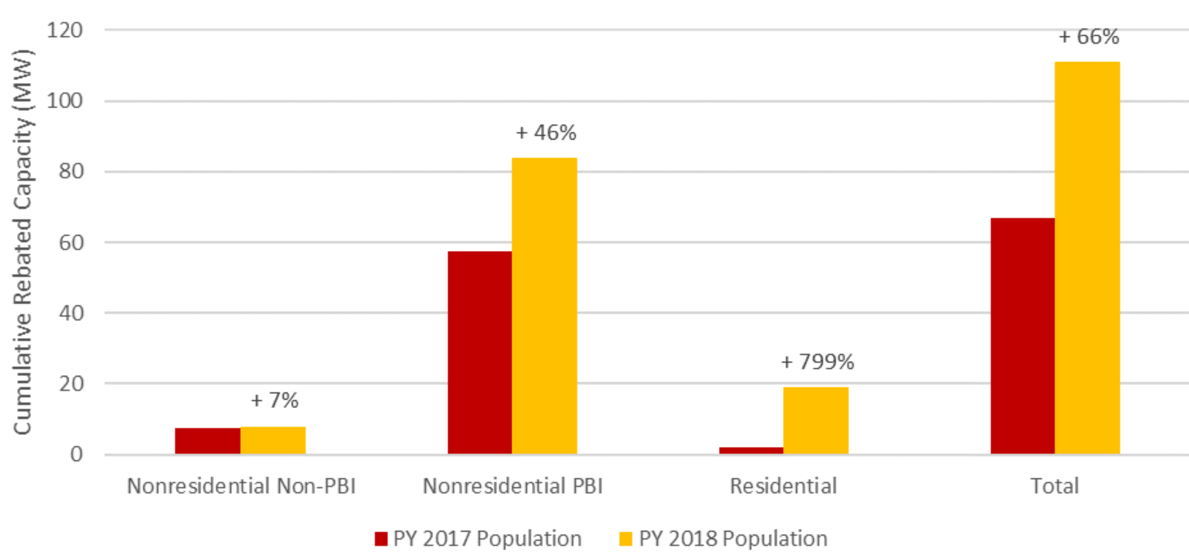


FIGURE 3-2: SGIP STORAGE CHANGE IN PROJECT COUNT FROM 2017 TO 2018 BY SECTOR AND PAYMENT TYPE

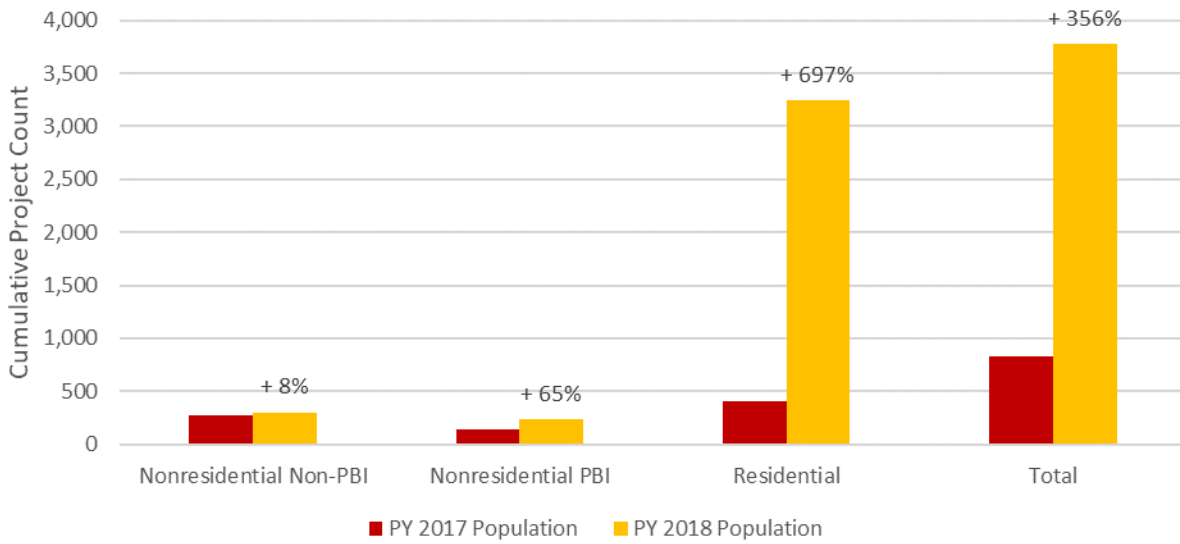


Table 3-1 presents the total number of projects in the 2018 population along with the total capacity for each customer segment and program administrator (PA). As discussed in Section 2, the 2018 population comprised of 539 nonresidential and 3,242 residential projects (3,781 total). Of the 539 nonresidential projects, 302 are non-PBI projects (< 30 kW) and 237 are PBI projects. Nonresidential projects (92 MW) account for a large majority of the total 111 MW. The most significant contribution of capacity comes from nonresidential PBI projects (84 MW). Residential projects, however, represent 86 percent of the population by project count.

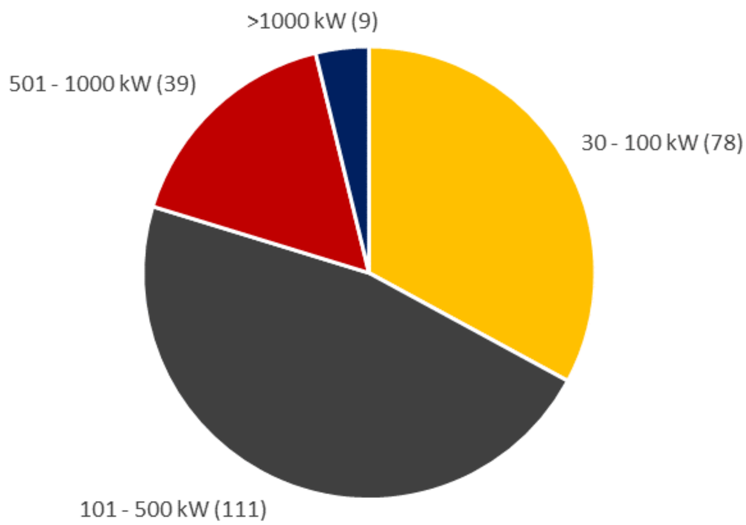
TABLE 3-1: 2018 SGIP POPULATION BY PA, CUSTOMER SECTOR AND INCENTIVE PAYMENT RULE

PA	Customer Segment	Project Count	% Project Count	Rebated Capacity (kW)	% Rebated Capacity (kW)
PG&E	Nonresidential Non-PBI	111	7%	3,302	9%
	PBI	60	4%	24,275	67%
	Residential	1,504	90%	8,911	24%
	All	**1,675**		**36,489**	
SCE	Nonresidential Non-PBI	108	8%	2,315	4%
	PBI	112	8%	43,205	83%
	Residential	1,132	84%	6,625	13%
	All	**1,352**		**52,145**	
CSE	Nonresidential Non-PBI	80	13%	1,733	9%
	PBI	60	9%	15,398	77%
	Residential	496	78%	2,808	14%
	All	**636**		**19,939**	
SCG	Nonresidential Non-PBI	3	3%	640	27%
	PBI	5	4%	1,099	46%
	Residential	110	93%	668	28%
	All	**118**		**2,407**	
Total	**Nonresidential Non-PBI**	**302**	**8%**	**7,989**	**7%**
	PBI	**237**	**6%**	**83,978**	**76%**
	Residential	**3,242**	**86%**	**19,013**	**17%**
	All	**3,781**		**110,980**	

3.1.1 PBI Population

The PBI population includes 237 AES projects that received their upfront payment any time prior to 2019. These projects represent a wide variety of customer types (with different load profiles) and use cases (e.g., demand charge reduction, time-of-use arbitrage) across each of the PA service territories. Figure 3-3 presents the distribution of PBI project counts by capacity bin. Most PBI projects (111) fall within the 100 to 500 kW SGIP rated capacity bin, followed by 30 to 100 kW systems (78) and 500 to 1,000 kW systems (39). Nine projects are greater than 1,000 kW, the largest being 2,600 kW.

FIGURE 3-3: 2018 SGIP PBI POPULATION BY REBATED CAPACITY BIN AND PROJECT COUNT



Another important characteristic of the population of projects is the customer segment. While there are a variety of system sizes subject to PBI requirements, the building types represented in the population are varied as well. Customer segments potentially have different operating schedules throughout the year which can have a significant impact on the behavior of the AES system. Some facilities may experience peak demand periods that are non-coincident to system peak hours, whereas the opposite may be true for others.

Figure 3-4 presents the building types representing the 2018 AES PBI projects (by project count) and Figure 3-5 presents the distribution of building types by rebated capacity. *Existing* projects are those that were subject to evaluation in PY 2017 and *New* projects are those incremental projects receiving their upfront payment in 2018. The *Total* PY 2018 evaluated population is the combination of the two. Industrial facilities, schools and offices represent the greater share of total project count at a combined 74 percent, followed by other[1] and retail. A similar pattern is evident when examining the distribution by rebated capacity. Twenty-two office projects received their upfront payment in 2018, increasing the total rebated capacity for that sector to 14 MW. For *New* projects that became operational during 2018, partial-year impacts will be developed based on the start of normal operations.

[1] This category includes warehouses, health care facilities, hotels and other miscellaneous building types.

FIGURE 3-4: 2018 SGIP PBI POPULATION BY BUILDING TYPE AND PROJECT COUNT

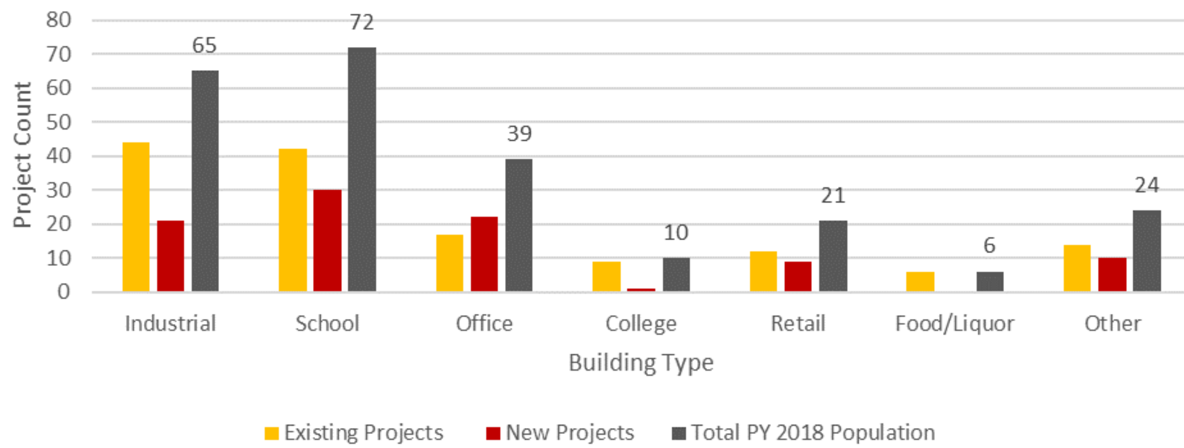
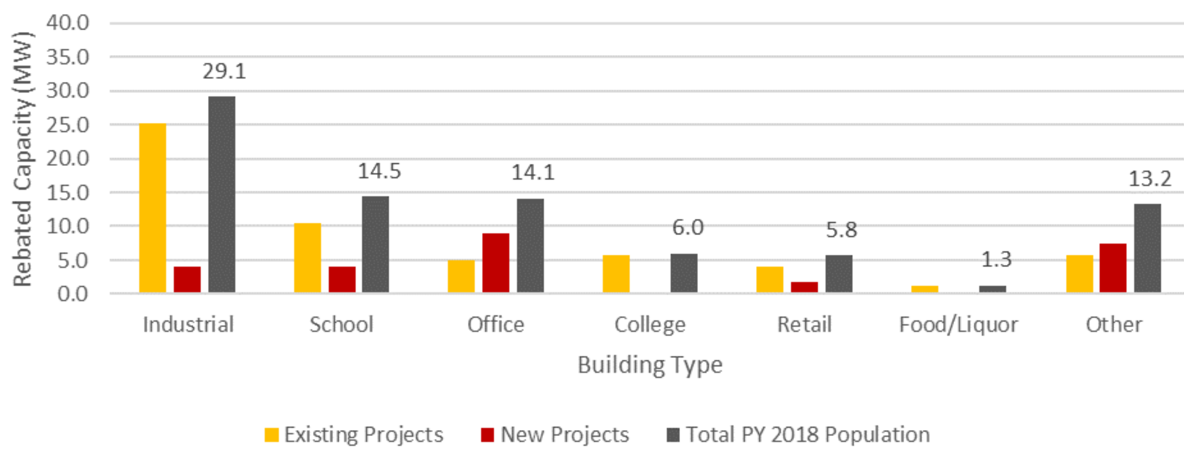


FIGURE 3-5: 2018 SGIP PBI POPULATION BY BUILDING TYPE AND REBATED CAPACITY

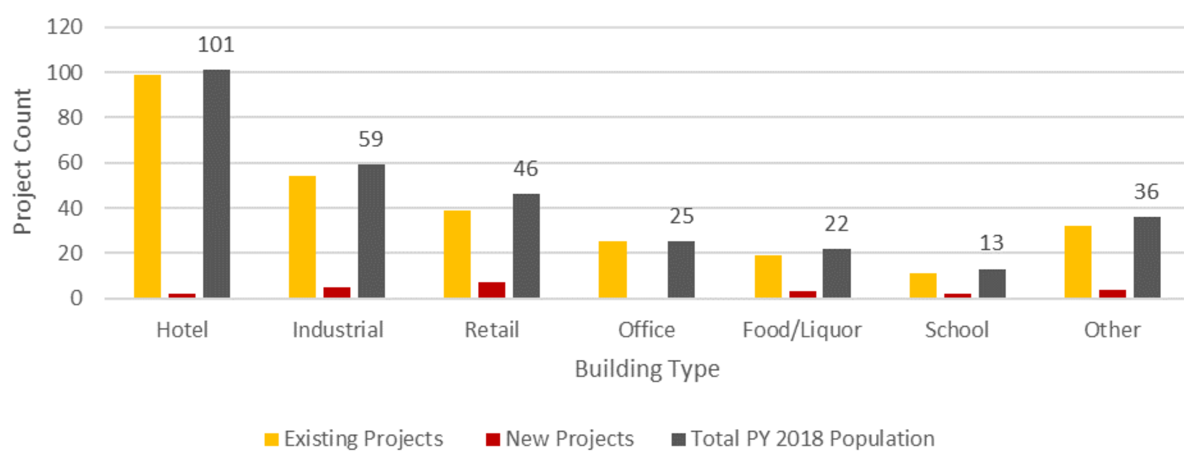


3.1.2 Nonresidential Non-PBI

The nonresidential non-PBI population comprises all AES projects with an SGIP rebated capacity less than 30 kW or rebated prior to PY 2011, regardless of capacity. Unlike PBI projects, non-PBI projects represent a narrower distribution in system sizes – the smallest being 5 kW and the largest 29.99 kW.[2] Much like PBI projects, however, they represent a variety of different facility types with potentially different operating schedules, load shapes and demand requirements.

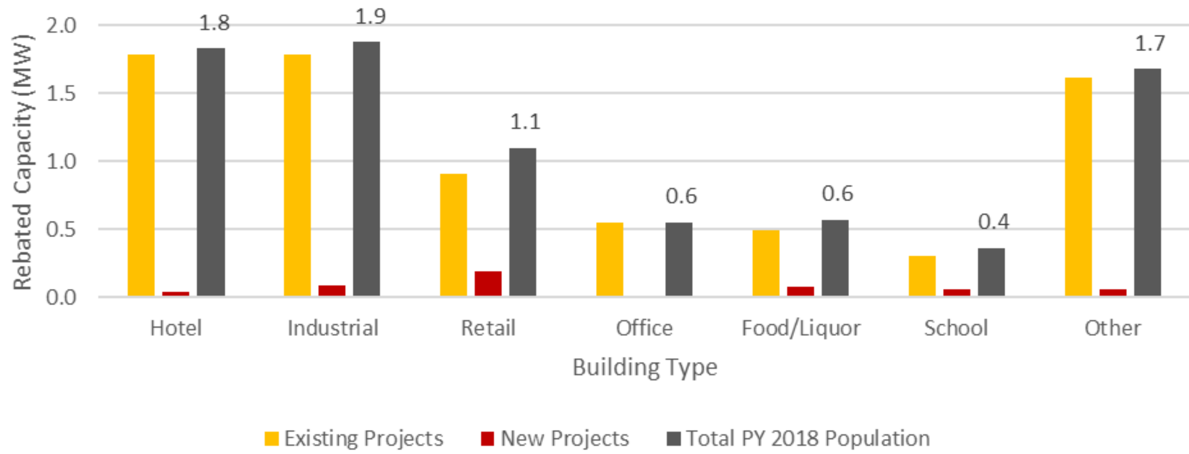
Figure 3-6 presents the distribution of building types representing the 2018 AES non-PBI projects (by project count) and Figure 3-7 presents the distribution of building types by rebated capacity. Again, *Existing* projects are those that were subject to evaluation in PY 2017 and *New* projects are those incremental projects receiving their upfront payment in 2018. There was tepid growth in the nonresidential non-PBI sector from PY 2017 to PY 2018. Hotels still represent the greater share of total project count at 33 percent, followed by industrial facilities and retail. However, when examining the distribution by rebated capacity, hotels represent a less significant share at 23 percent. As mentioned above, there are two large systems – one installed in an industrial facility and one in the "other" category – that are not subject to PBI requirements. These systems have a significant impact on the total capacity within each of those building type categories. Again, for *New* projects that became operational during 2018, partial-year impacts will be developed based on the start of normal operations.

FIGURE 3-6: 2018 SGIP NON-PBI NONRESIDENTIAL POPULATION BY BUILDING TYPE AND PROJECT COUNT



[2] Two additional projects – 1,000 and 600 kW systems – applied to the program prior to PY 2011 and therefore are not subject to Senate Bill (SB) 412 provisions and PBI program requirements.

FIGURE 3-7: 2018 SGIP NON-PBI NONRESIDENTIAL POPULATION BY BUILDING TYPE AND REBATED CAPACITY



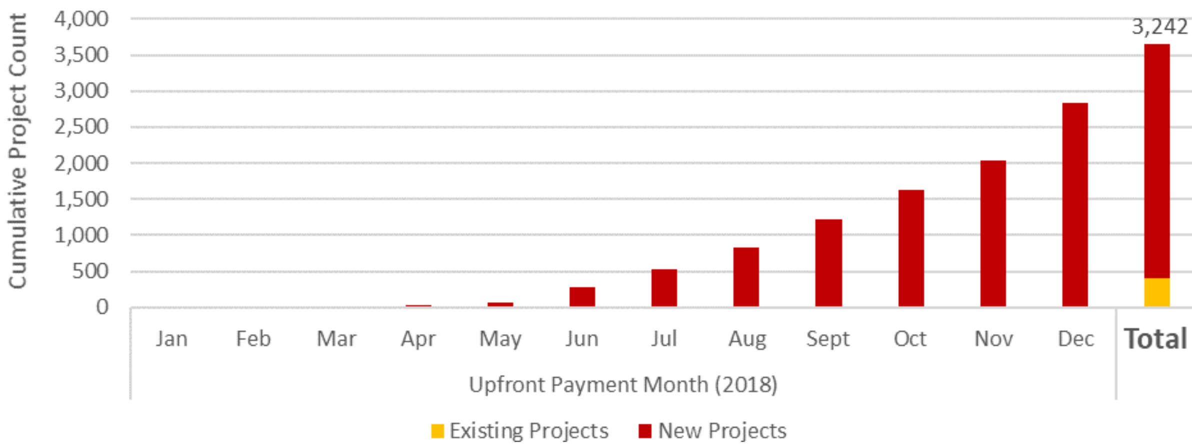
3.1.3 Residential Non-PBI

Residential projects comprise 3,242 SGIP AES projects subject to evaluation for 2018. This sector represents roughly 86 percent of the 2018 population by project count. These systems are smaller than systems installed within commercial or industrial facilities. Of the total residential systems represented in the population, 80 percent are within 4.5 and 5 kW in rebated capacity. Therefore, their contribution to total population rebated capacity (17 percent) is much less than the 86 percent representation by project count. However, growth in this sector from PY 2017 to PY 2018 has been substantial, as evident in Figure 3-1 and Figure 3-2.

Much like the nonresidential population, residential systems are being installed by a variety of project developers, especially in 2018. However, two battery models represent over 97 percent of total installations through December 31st of 2018 – Tesla Powerwall 2.0s and LG Chem batteries paired with SolarEdge inverters.

The roughly 700 percent increase in residential project count from PY 2017 to PY 2018 presents some unique opportunities as well as some unique challenges. As discussed previously in Section 2, while a storage project may apply to and be admitted into the SGIP during one calendar year, there is often a lag time between when that customer receives their permission-to-operate (PTO) and the incentive. Figure 3-8 presents the distribution of residential projects subject to evaluation for PY 2018 by upfront payment month. Most projects received payment later in the year with 70 percent receiving upfront incentives from September through December 2018. From the sample of projects that became operational during 2018, partial-year impacts will be developed based on the start of normal operations.[3]

FIGURE 3-8: 2018 SGIP RESIDENTIAL POPULATION BY PROJECT COUNT



3.2 SGIP 2018 SAMPLE CHARACTERIZATION OF AES PROJECTS

The observed impacts presented in this study rely on metered performance data from AES systems. We developed a sample to optimize time spent performing quality control tasks and in-depth analyses. Below we present the separate sampling approaches for PBI and non-PBI projects.

3.2.1 PBI Sample Disposition

PBI projects represent roughly 84 MW of the SGIP AES program capacity of 111 MW. The 84 MW represent a 46 percent increase in SGIP rebated capacity from 2017. There are 237 PBI projects subject to measurement and verification, which represents a 65 percent increase by project count from 2017.

For the 2016 and 2017 AES impact studies the evaluation team did not employ any sampling strategy to develop impacts for PBI projects, but rather attempted a census of all projects. The evaluation team utilized the same approach for 2018, given the weight these projects represent in the SGIP storage population. As discussed in Appendix B, we downloaded all available data from the PBI web portal and placed separate data requests to individual project developers and host customers. We also requested and received metered load data from each of the IOUs.

[3] The start of normal operations can be on or after the PTO date, but no later than the upfront incentive payment date. Itron reviews each customer's storage profile to determine the start of normal operations and maximize the use of available metered data.

Table 3-2 presents the total number of projects in the population (shown as 'N') along with the total capacity of all PBI projects by PA as well as the statewide total. Table 3-2 also presents the total number of projects represented in the analysis sample (shown as 'n'). The 2017 evaluation year includes all projects in the SGIP population subject to evaluation in 2017 and those in the 2018 evaluation year represent the incremental projects receiving upfront payments in 2018 and were not subject to evaluation in 2017. The analysis sample represents 211 of the 237 projects subject to evaluation in 2018 which accounts for roughly 89 percent of all PBI projects by project count and 94 percent by rebated capacity.

While it was our intention to conduct measurement and verification on all 2018 PBI projects, we uncovered some data limitations and data quality issues which precluded a rigorous evaluation of all projects in the population. If a project was missing long intervals of storage charge/discharge data or if the evaluation team determined that the storage dispatch behavior did not coincide with the metered load data at the same interval, these projects were flagged for further quality control. If the issues could not be resolved, the project was removed from the analysis. Further discussion of the quality control exercises that were performed to verify storage data can be found in Appendix B.

TABLE 3-2: 2018 SGIP PBI POPULATION AND SAMPLE DISPOSITION BY PA

PA	Year	Project Count				Rebated Capacity (MW)		
		N	Expected n	Achieved n	% in Sample	N	Achieved n	% in Sample
PG&E	2017	43	43	37	86%	21,088	20,089	95%
	2018	17	17	16	94%	3,188	2,753	86%
SCE	2017	52	52	42	81%	22,434	19,992	89%
	2018	60	60	55	92%	20,771	20,176	97%
SCG	2018	5	5	5	100%	1,099	1,099	100%
CSE	2017	49	49	46	94%	13,818	13,594	98%
	2018	11	11	10	91%	1,580	1,475	93%
All Projects	2017	144	144	125	87%	57,341	53,674	94%
	2018	93	93	86	92%	26,638	25,503	96%
	Total	**237**	**237**	**211**	**89%**	**83,978**	**79,177**	**94%**

3.2.2 Non-PBI Nonresidential Sample Disposition

Nonresidential non-PBI projects represent roughly 8 MW of the SGIP AES program capacity of 111 MW. The 8 MW represent a 7 percent increase in rated capacity within SGIP from 2017. There are 302 non-PBI nonresidential projects subject to measurement and verification which represents an 8 percent increase by project count from 2017.

Given there are no PBI data delivery requirements for projects less than 30 kW, storage data supplied by the project developer, is the only data source to measure and verify impacts from these projects. Given the increase in total projects, evaluation reporting deadlines, budgetary considerations, results garnered from the 2017 impact evaluation, along with the understanding that there are far more PBI and residential projects subject to review (by count and rebated capacity) in 2018, we have developed a dedicated sampling approach that limits sampling error and provides statistically significant impact results for non-PBI nonresidential projects online in 2018.

Throughout the course of the 2016 and 2017 impact evaluations, we satisfied several evaluation objectives, including the development of storage and customer impact metrics. While conducting those analyses, we identified patterns and developed insights which better explained how storage was being dispatched. Storage systems were being utilized to reduce or shift customer load requirements and this behavior provided economic benefits to customers by way of bill savings. While the storage dispatch objectives were similar for all projects, the behavior and the manner in which these economic benefits were realized were based on customer rate class, facility operating schedules and load profiles.

The evaluation team examined two design variables – roundtrip efficiencies (RTEs) and greenhouse gas emissions – from the 2016 AES impact evaluation. These design variables were constructed around 2016 non-PBI nonresidential storage systems by building type to ascertain whether there were any significant differences across and within groups and to inform our sample design strategy for 2018. The results of that exercise provided the evaluation with the minimum number of sample projects required to develop population-level SGIP storage impacts at a high level of precision (10 percent relative precision measured at the 90 percent confidence level or 90/10).

Table 3-3 presents the proposed and achieved sample design for 2018 non-PBI nonresidential projects. The total number of projects and rebated capacity are provided by building type and evaluation year. Again, the total number of projects and rebated capacity in the population are denoted as 'N'. The expected 'n' represents the number of projects incorporated into the sample design prior to the commencement of the impact evaluation and the achieved 'n' is the number of projects and rebated capacity ultimately included in the evaluation.

The 2017 evaluation year includes all projects in the SGIP population subject to evaluation in 2017 and those in the 2018 evaluation year represent the incremental projects receiving upfront payments in 2018 and were not subject to evaluation in 2017. The sample design was constructed around projects in the 2017 evaluation year and the evaluation team attempted a census on all 2018 projects.

Overall, the evaluation team expected to evaluate operations for 147 of the 302 projects in the SGIP non-PBI nonresidential population and, ultimately, evaluated 137 projects across the previously defined evaluation years. We met or exceeded all sampling targets for the 2017 evaluation year and were successful in evaluating 13 of the 23 projects in the 2018 evaluation year. The 147 projects represent 45 percent of all non-PBI nonresidential projects in the population and 58 percent of total rebated capacity.

TABLE 3-3: 2018 SGIP NON-PBI NONRESIDENTIAL POPULATION AND SAMPLE DISPOSITION BY STRATA

Building Type Strata	Year	Project Count				Rebated Capacity (kW)		
		N	Expected n	Achieved n	% in Sample	N	Achieved n	% in Sample
Food/Liquor	2017	17	10	10	59%	459	267	58%
	2018	3	3	3	100%	75	75	100%
Hotel	2017	98	15	15	15%	1,767	301	17%
	2018	2	2	2	100%	45	45	100%
Industrial	2017	35	15	15	43%	807	388	48%
	2018	5	5	4	80%	90	75	83%
Office	2017	24	10	11	46%	535	233	44%
Other	2017	24	15	15	63%	470	317	67%
	2018	4	4	1	25%	65	29	45%
Retail	2017	33	15	15	45%	784	292	37%
	2018	7	7	3	43%	194	89	46%
School	2017	11	6	6	55%	306	180	59%
	2018	2	2	0	0%	60	-	0%
Census1	*2017*	*1*	*1*	*1*	*100%*	*1,000*	*1,000*	*100%*
Census2	*2017*	*1*	*1*	*1*	*100%*	*600*	*600*	*100%*
Special Case	*2017*	*35*	*35*	*35*	*100%*	*734*	*734*	*100%*
All Projects	2017	279	124	124	44%	7,461	4,312	58%
	2018	23	23	13	57%	529	314	59%
	Total	**302**	**147**	**137**	**45%**	**7,989**	**4,625**	**58%**

The evaluation team deviated from the random stratified sampling approach for three unique circumstances – denoted as *Census1*, *Census2* and *Special Case* in the above table. *Census1* and *Census2* represent two large storage systems, a 600 kW industrial project and a 1,000 kW jail, not subject to PBI program requirements because they applied to the SGIP program prior to 2011. These systems are significantly larger than any other projects in the non-PBI nonresidential population and would carry an inordinate impact if they were randomly sampled with other projects. Furthermore, the evaluation team contacted the host customers for both projects and received confirmation that both systems were completely off-line in 2017 and, subsequently, in 2018. *Special Case* represents 35 storage systems from a developer that filed bankruptcy. The evaluation team was also able to surmise that more than 60 percent of these systems had either been removed from the host customers' premises or had been off-line in 2017-2018.

While these projects weren't "sampled", the evaluation team developed impacts for them, even if they were "zero" impacts. In the subsequent sections of the observed impacts section, all 37 of these projects have been removed from the analysis. These systems were off-line or decommissioned in 2017-2018 and it's understood they contributed no (or "zero") impacts throughout the year. However, these projects are included in the population impact section because they are represented in the 2018 SGIP AES population. A "zero" impact is an impact, nonetheless, and it's critical to capture this when developing population-level impacts of the SGIP.

3.2.3 Residential Sample Disposition

Residential projects represent roughly 19 MW of the SGIP AES program capacity of 111 MW. The 19 MW represent a 799 percent increase in rebated capacity for residential projects within SGIP from 2017. There are 3,242 residential projects subject to measurement and verification which represents a 697 percent increase by project count from 2017. The storage systems range in rebated capacity with roughly 80 percent representing 4.5 to 5 kW systems.

As discussed in Appendix B, this evaluation relies heavily on storage data from project developers and manufacturers. The 2016 impact evaluation revealed significant limitations in some storage project developer and manufacturer data acquisition systems that impacted our ability to rigorously evaluate residential projects. Our assessment of residential program impacts in 2016 was limited in scope as a result, so our team provided a qualitative rather than quantitative assessment of residential storage system impacts.[4] To address these shortcomings in the 2017 impact evaluation, our team leveraged an additional data source to develop impacts for SGIP residential projects. Itron and its subcontractors

[4] Multiple projects from SGIP residential project developers showed roundtrip efficiencies over 100 percent, leading us to conclude the data were suspect enough to not be usable in quantitative analyses.

installed metering at 30 residential energy storage projects to meter storage dispatch, solar PV generation and customer load, where possible, throughout the latter part of 2016 and into early 2017. These meters were installed and operating throughout the entirety of 2018 and data from these meters have allowed the evaluation team to better quantify the impacts from systems that previously could not be evaluated.

As mentioned previously, the growth in residential storage projects receiving incentives in 2018 is attributed to newer and more sophisticated storage systems capable of operating under different modes and conditions. These systems also maintain more robust and reliable data acquisition systems which allow for a far more rigorous analysis of impacts. Our team requested and received storage, PV generation and customer load data from over 70 percent of these newer systems. Our sample was drawn from these projects along with the 30 previously metered projects representing the existing population of projects.

Table 3-4 presents the sample disposition for residential projects by PA. Of the 30 projects representing the 2017 population, 29 were ultimately utilized for analysis. Overall, these projects represent roughly 7 percent of all 2017 residential projects by project count and rebated capacity. For the newer projects receiving upfront payments in 2018, the evaluation drew a sample of 255 projects and was successful in meeting that quota. These projects represent 9 percent of the 2018 residential population by project count and 10 percent, by rebated capacity.

TABLE 3-4: 2018 SGIP RESIDENTIAL POPULATION AND SAMPLE DISPOSITION BY PA

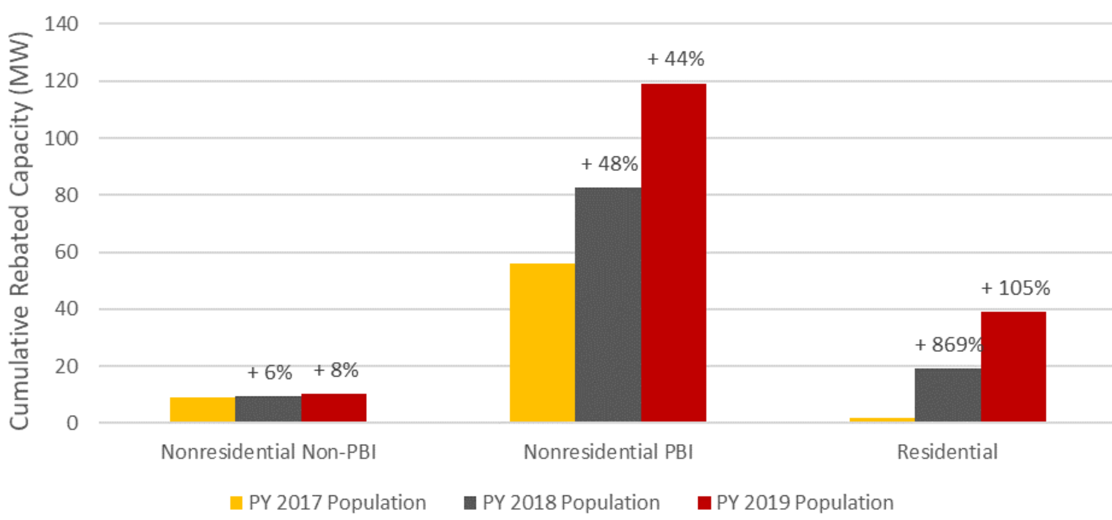
PA	Year	Project Count				Rebated Capacity (MW)		
		N	Expected n	Achieved n	% in Sample	N	Achieved n	% in Sample
PG&E	2017	173	16	15	9%	892	75	8%
	2018	1,331	115	115	9%	8,019	752	9%
SCE	2017	139	8	8	6%	714	40	6%
	2018	993	87	87	9%	5,911	576	10%
SCG	2017	1	0	0	0%	14	0	0%
	2018	109	3	3	3%	654	20	3%
CSE	2017	94	6	6	6%	496	30	6%
	2018	402	50	50	12%	2,327	310	13%
Total	2017	407	30	29	7%	2,116	145	7%
	2018	2,835	255	255	9%	16,912	1,658	10%
	Total	**3,242**	**285**	**284**	**9%**	**19,028**	**1,803**	**9%**

3.3 SGIP POPULATION BEYOND 2018

The above sections detail the characterization of the SGIP AES population subject to evaluation in 2018 and provides a summary of how changes to the disposition of that population from 2017 to 2018 dictated the evaluation approach. Residential PBI projects constitute the most significant percentage of systems receiving upfront payments in 2018 from PY 2017 and prior (both in terms of project count and rebated capacity). Likewise, PBI projects subject to evaluation increased substantially as well. While the remainder of this report presents the results associated with projects subject to evaluation in 2018, here we provide a snapshot of how the disposition of the population is changing from 2018 to 2019. 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.

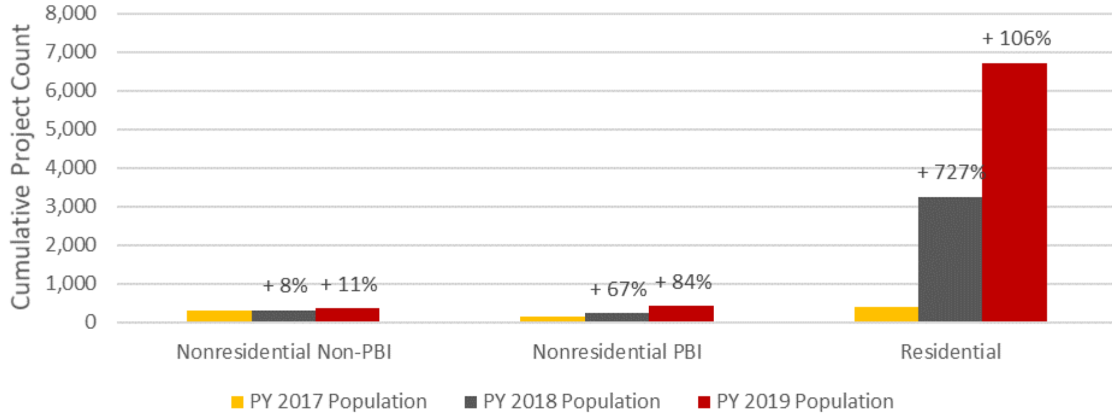
Figure 3-9 and Figure 3-10 present the growth in the SGIP for storage technologies from PY 2017 – PY2019. As evident in the current PY 2018 AES population, residential projects experienced a significant growth in total project count and capacity from the previous evaluation period. This growth has continued into PY 2019 as well. Residential project capacity subject to evaluation in PY 2019 has already grown 105 percent and nonresidential PBI growth has increased by 44 percent.[5] In all, the energy storage population in the SGIP is comprised of over 7,500 projects and roughly 170 MW of rebated capacity.

FIGURE 3-9: GROWTH IN THE SGIP AES POPULATION FROM PY 2017 – PY2019 (BY REBATED CAPACITY)



[5] The SGIP project list was accessed on 10/1/2019, so the capacities and project counts discussed above are for projects receiving upfront payments from that day and prior. There are still 3 months left in 2019 for projects to receive their payment and be subject to evaluation in PY2019. These counts are likely to increase further.

FIGURE 3-10: GROWTH IN THE SGIP AES POPULATION FROM PY 2017 – PY2019 (BY PROJECT COUNT)



The significant growth in these sectors along with other storage technologies like thermal storage receiving upfront payments in 2019 will shape the impacts of the SGIP in the coming years.

4 OBSERVED ADVANCED ENERGY STORAGE IMPACTS

4.1 OVERVIEW

The primary objective of this study is to evaluate the performance of advanced energy storage (AES) systems rebated through the SGIP and operating during calendar year 2018. The evaluation team analyzed several different impact metrics:

- **Observed Performance Impact Objectives – Section 4.2**
  - Calculate roundtrip efficiencies and capacity factors
  - Quantify parasitic load influence on storage performance
- **Observed Customer Impact Objectives – Section 4.3**
  - 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 Impact Objectives – Section 4.4**
  - Analyze and quantify charge/discharge behavior in relation to CAISO system load and utility coincident peak demand
- **Observed Environmental Impact Objectives – Section 4.5**
  - Analyze and quantify charge/discharge behavior in relation to marginal greenhouse gas (GHG[1]) and criteria air pollutant[2] emission rates
- **Observed Utility Marginal Cost Impact Objectives – Section 4.6**
  - Analyze and quantify charge/discharge behavior in relation to utility energy, system capacity, transmission, distribution, renewable portfolio standard (RPS) and ancillary services costs as quantified in the CPUC Avoided Cost Calculator

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1 This greenhouse gas emission impact analysis is limited to emissions from grid-scale gas power plants. Carbon Dioxide (CO_2) emissions were the only greenhouse gas modeled in this study. Throughout this report the terms "Greenhouse Gas" and "CO_2" are used interchangeably.

2 This criteria air pollutant impact analysis is limited to particulate matter (PM_{10}) and Nitrogen Dioxides (NOx) emissions generated from grid-scale gas power plants. PM_{10} are airborne particles ranging from 10 micrometers in diameter or smaller and are a byproduct of fuel combustion in electric generation power plants. NOx, the collective name of Nitrogen Dioxide and Nitrogen Oxides, are gases produced from the reaction of nitrogen and oxygen gases in the air as a byproduct of fuel combustion.

- **Observed Demand Response (DR) Program Objectives – Section 4.7**
  - Analyze and quantity how storage systems are being utilized for customers participating in DR programs. This analysis includes quantifying the magnitude of charge/discharge behavior during DR events compared to non-event periods and how these DR event signals impact GHG emissions
- **Population Level Impact Objectives – Section 4.8**
  - Combine project-specific sample data from the objectives above to *quantify the magnitude* of total population level impacts for SGIP AES systems operating throughout 2018

4.2 PERFORMANCE METRICS

Below we present the performance metrics developed from the sample of projects evaluated as part of the 2018 AES impact evaluation.

4.2.1 Capacity Factor and Roundtrip Efficiency

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 within a given time 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 assumes 5,200 maximum hours of operation in a year rather than the full 8,760 hours (60 percent). This is to account for the fact that "Advanced Energy Storage Projects typically discharge during peak weekday periods and are unable to discharge during their charging period."[3] For purposes of SGIP evaluation, the AES capacity factor is calculated as:

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

[3] See 2015 SGIP Handbook, p. 37.

The SGIP Handbook requires that PBI projects that applied prior to 2017 achieve an AES capacity factor of at least 10 percent per the above formula, 520 hours of equivalent full discharge over the course of each year, to receive full payment.[4] Non-PBI projects are not required to meet a 10 percent capacity factor to capture the entire performance based incentive.[5]

Another key performance metric is roundtrip efficiency (RTE), which is an eligibility requirement for the SGIP.[6] The RTE is defined as the total kWh discharge of the system divided by the total kWh charge and, for a given period of time, should range from 0 percent to 100 percent. For SGIP evaluation purposes, this metric was calculated for each project over the whole period for which dispatch data were available and deemed verifiable. RTEs should never be greater than 100 percent when calculated over the course of a couple of days or a month. The evaluation team carefully examined the RTEs for each project as part of the QC process to verify that there were no underlying data quality issues.

Nonresidential Project CFs and RTEs

The capacity factors for the sample of nonresidential AES projects are presented below in Figure 4-1. A total of 178 nonresidential projects have capacity factors of less than 5 percent (of 348 total sampled projects) with PBI projects representing 86 of the total projects. We observed 107 nonresidential projects with a capacity factor between 5 and 10 percent with 44 of those representing non-PBI projects and 63 representing PBI projects. Sixty-one projects exhibited capacity factors of a least 10 percent. All but 13 of these projects were PBI. Furthermore, one non-PBI project and one PBI project exhibited a capacity factor greater than 20 percent. The mean capacity factor was 4.4 percent for non-PBI projects and 6.5 percent for PBI projects during the evaluation period.

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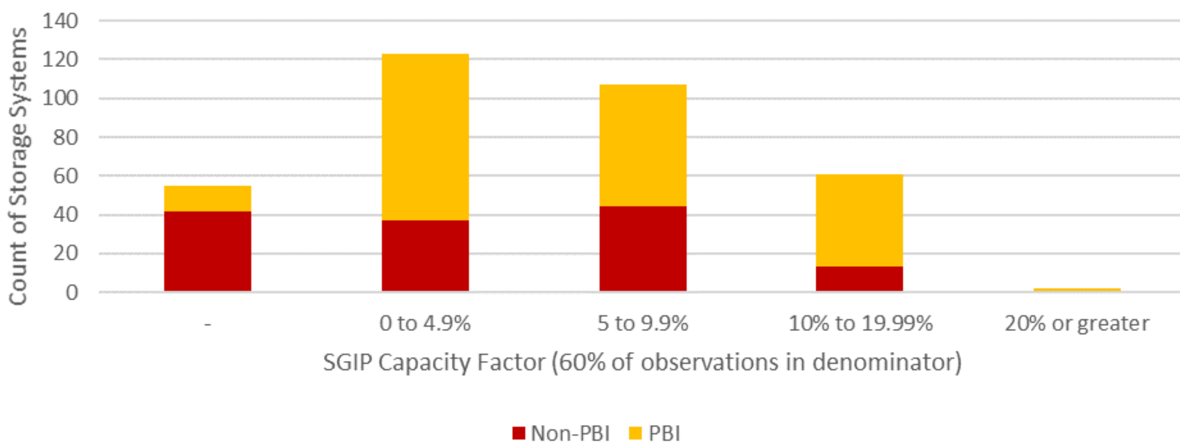
4 "520 discharge hours" refers to the amount energy released when discharging a battery at full capacity for 520 hours. AES projects typically discharge during peak weekday periods and are unable to discharge during their charging period. For this reason, 5,200 hours per year will be used for the purposes of calculating the capacity factor for AES projects. That is, a system may discharge at full capacity for 520 hours, or, say, 50 percent capacity for 1,040 hours – the amount of energy in the two is the same, each constituting 520 discharge hours.

5 Going forward, the SGIP will emphasize "number of discharges" as the preferred metric for system utilization in lieu of capacity factor. This evaluation focuses on capacity factor as the utilization metric since this was the primary requirement in place when the vast majority of projects subject to evaluation had their applications submitted to the program.

6 AES 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. (2016 SGIP Handbook, https://www.selfgenca.com/documents/handbook/2016)

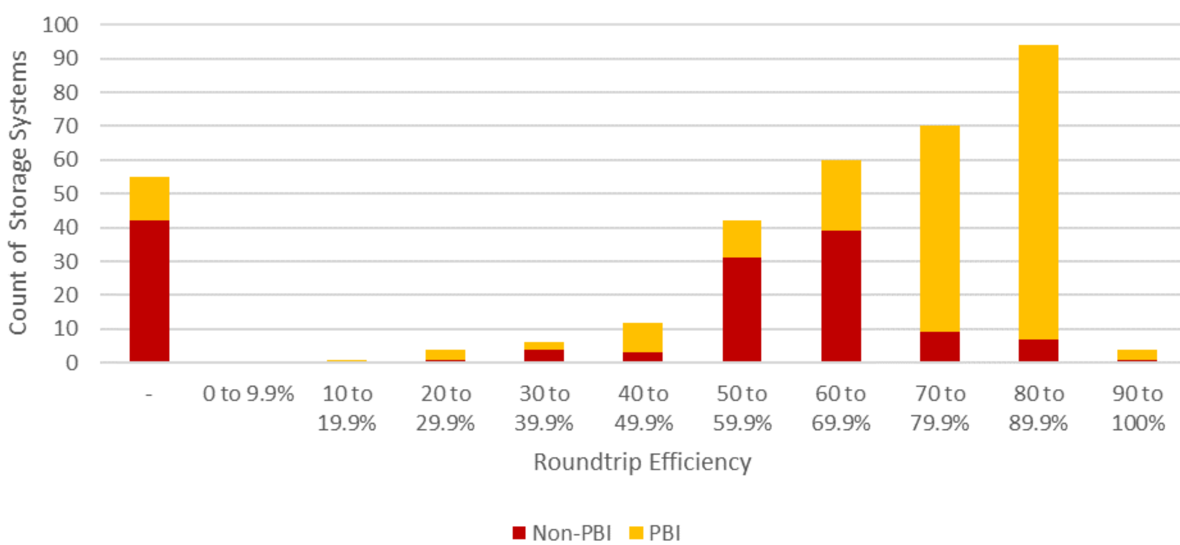
FIGURE 4-1: HISTOGRAM OF NONRESIDENTIAL AES DISCHARGE CAPACITY FACTOR (2018)



* Fifty-five projects were offline throughout the entirety of 2018, had been decommissioned or received their upfront payment so late in the year that no impacts were measured. These projects are reported as "-" above.

Figure 4-2 presents the distribution of RTEs for PBI and non-PBI projects. Besides offline and decommissioned systems, few projects exhibit an annual RTE of less than 50 percent. Most PBI projects are within the 70 to 90 percent range, while most non-PBI projects are within the 50 to 70 percent range. The observed RTE was 63 percent for non-PBI projects and 81 percent for PBI projects over the entire evaluation period.

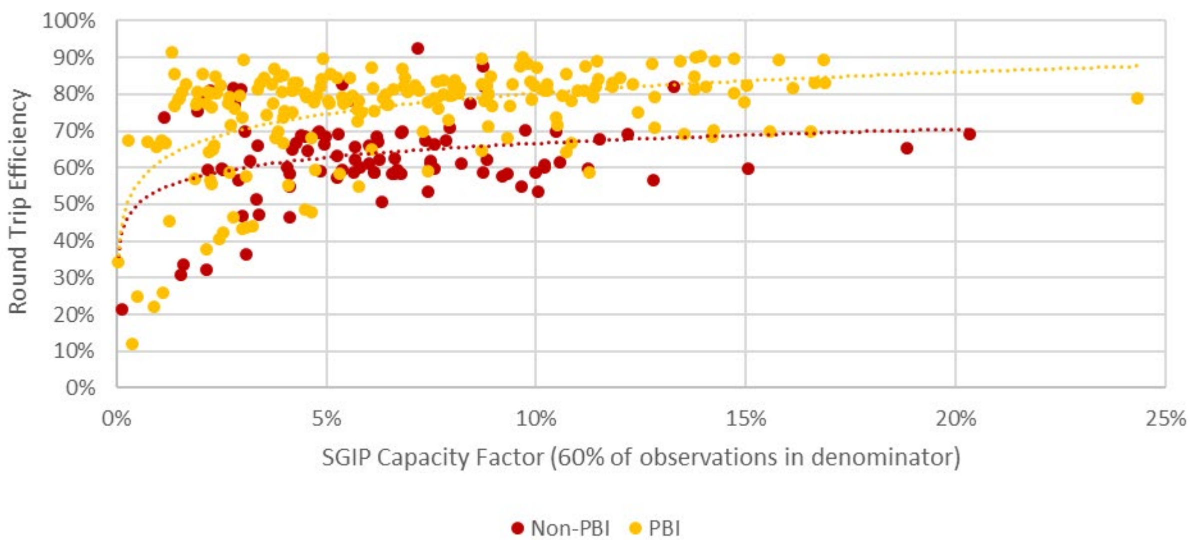
FIGURE 4-2: HISTOGRAM OF NONRESIDENTIAL ROUNDTRIP EFFICIENCY (2018)



* Fifty-five projects were offline throughout the entirety of 2018, had been decommissioned or received their upfront payment so late in the year that no impacts were measured. These projects are reported as "-" above

Note that by calculating the RTE over the course of several months, the metric not only captures the losses due to AC-DC power conversion but also the parasitic loads associated with system cooling, communications and other power electronic loads. Parasitic loads can represent a significant fraction of total charging energy (the denominator in the RTE calculation), especially for systems that are idle for extended periods. This relationship is exhibited in Figure 4-3. Systems with the lowest capacity factors tend to have the lowest RTEs.

FIGURE 4-3: TOTAL ROUNDTRIP EFFICIENCY VERSUS CAPACITY FACTORS (ALL NONRESIDENTIAL PROJECTS)



Residential Project CFs and RTEs

The capacity factors for residential projects are presented below in Figure 4-4. A total of 25 projects had capacity factors of less than 2 percent (of 284 total sampled projects) and 125 projects exhibited a capacity factor between 2 and 5 percent. Ninety-one projects were between 5 and 10 percent and 43 projects exhibited a CF greater than 10 percent. Note the capacity factor is calculated over the time period with available data and after start of normal operations, so a project CF with metered data available from March through December of 2018 would be calculated only for that period of time (the hours of available data in the denominator of the CF calculation would exclude hours in January and February). The mean capacity factor was 5.8 percent for residential projects during the evaluation period.

FIGURE 4-4: HISTOGRAM OF RESIDENTIAL AES DISCHARGE CAPACITY FACTOR (2018)

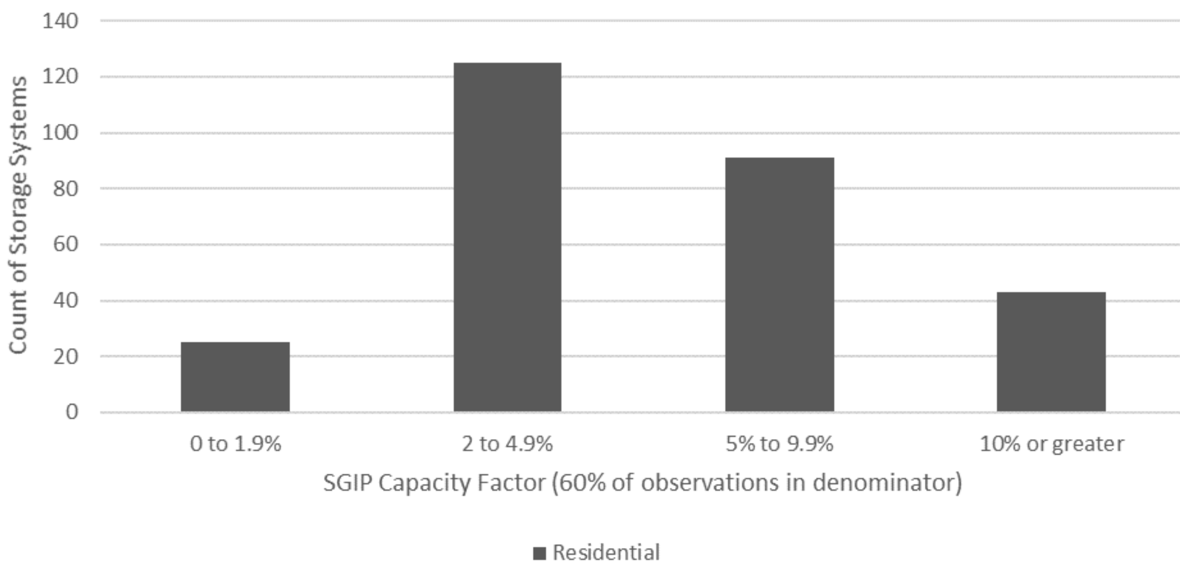
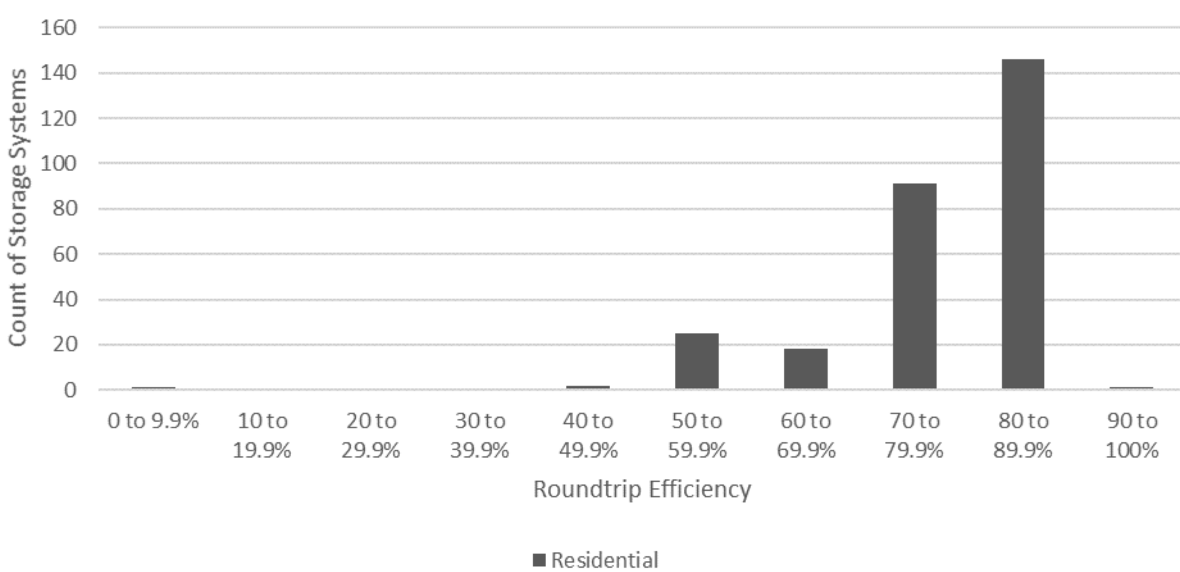


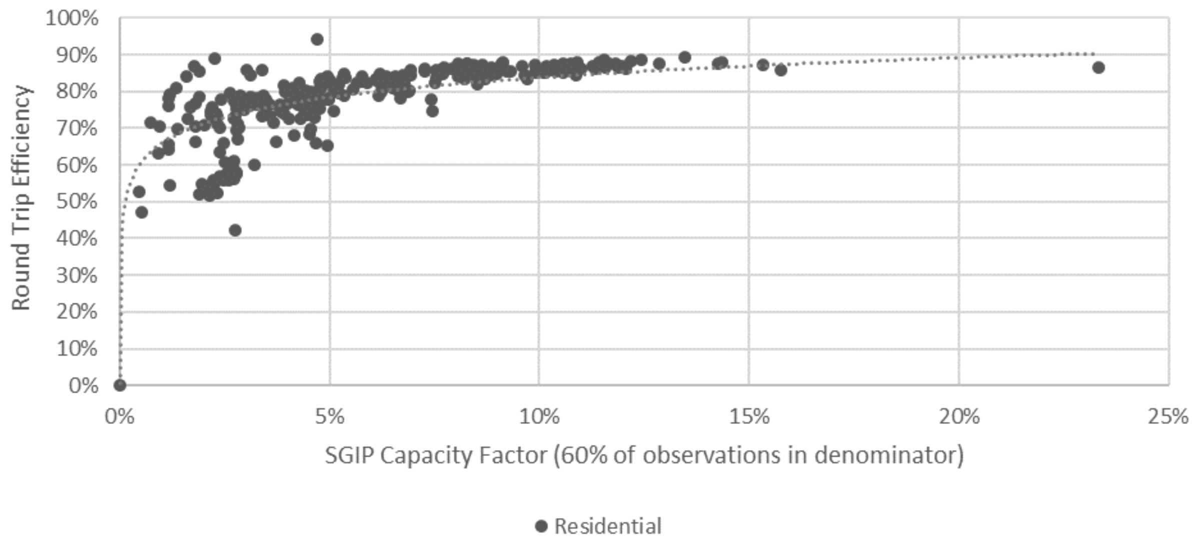
Figure 4-5 presents the distribution of RTEs for the 284 residential projects. Only 3 projects exhibited an RTE less than 50 percent (one of which was a system that remained idle for the entirety of the metered period). Most projects (237) exhibited RTEs in the 70 percent to less than 90 percent range. The observed residential RTE was 78 percent.

FIGURE 4-5: HISTOGRAM OF RESIDENTIAL ROUNDTRIP EFFICIENCY (2018)



Again, the annual RTE is calculated over the course of several months, and the metric not only captures the losses due to AC-DC power conversion, but also the parasitic loads associated with system cooling, communications and other power electronic loads. Figure 4-6 presents the relationship between utilization and efficiency for residential projects.

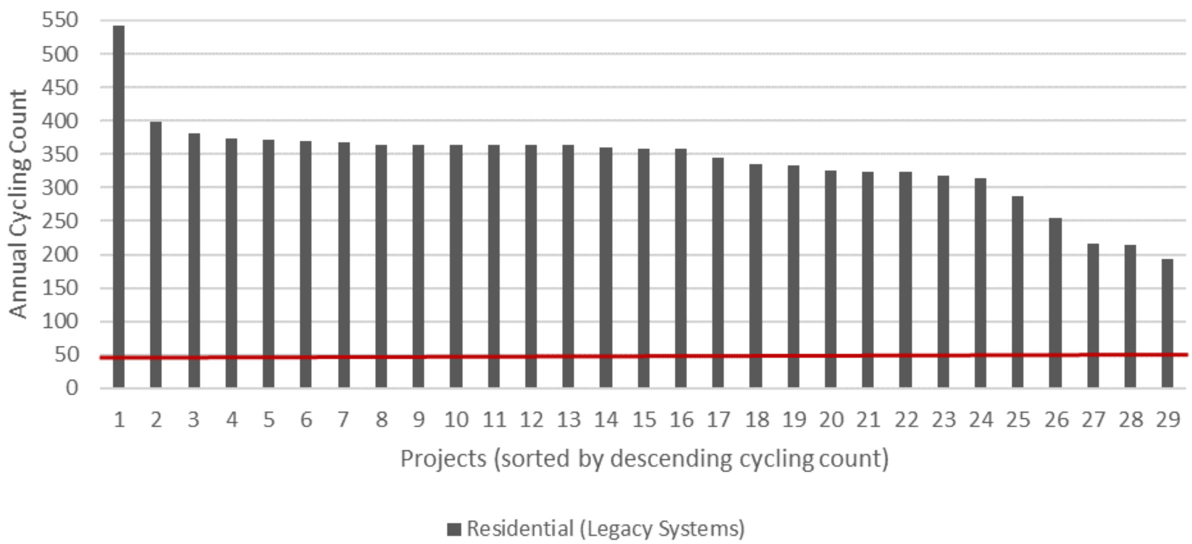
FIGURE 4-6: TOTAL ROUNDTRIP EFFICIENCY VERSUS CAPACITY FACTORS (ALL RESIDENTIAL PROJECTS)



Results from the 2017 evaluation revealed that legacy residential storage systems were cycling throughout the year. The SGIP requires residential storage systems to cycle 52 times throughout the year.[7] The evaluation team found evidence that 23 of the 28 systems with metered data reached that 52-cycle minimum in 2017. However, these systems were generally not being utilized and remained idle throughout most of the year and would only start cycling daily in the latter months. More sophisticated storage systems, PV pairing and changing residential rate schedules – the transition from tiered volumetric rates to TOU rates – have helped assuage concerns that storage systems are being utilized only for back-up purposes and are just meeting minimum cycling requirements. The higher RTEs and CFs are evidence of that transition. Our team conducted an analysis of how these legacy systems were operating during 2018. While there's evidence these systems are cycling throughout the year and are not exhibiting sophisticated charge and discharge patterns, the frequency of cycles have increased substantially. Figure 4-7 provides evidence that these systems are cycling almost daily in 2018.

[7] https://www.selfgenca.com/documents/handbook/2017

FIGURE 4-7: ANNUAL SINGLE CYCLE EVENTS FOR SAMPLE OF LEGACY RESIDENTIAL PROJECTS



4.2.2 Cross-Year Performance Impact Comparisons (2017 to 2018)

The evaluation team also compared the performance metrics developed from the 2017 impact evaluation to those garnered from this evaluation. These comparisons were made for project-specific RTEs and capacity factors to highlight any potential changes in operation or utilization from one year to the next. Projects that came online during 2018 are not compared to projects in the 2017 population. Instead, the analysis is limited to the 177 projects that were operational during both 2017 and 2018. It is important to note, many projects evaluated in 2017 received their upfront payments at different times throughout the year, so the performance metrics did not incorporate a full calendar year of impacts. All projects completed during 2017 were online and operating throughout the entirety of 2018, so any potential changes in performance from one year to the next may only reflect that difference.

Figure 4-8 through Figure 4-11 present those comparisons for RTEs and CFs. Any point on the figure above the black line represents a project with a greater RTE in 2018 relative to 2017. On average, non-PBI projects exhibit greater RTEs in 2018 (65 percent) compared to their own operation in 2017 (54 percent). For PBI projects, the differences are marginal. Non-PBI projects generally are being utilized more in 2018 (3.8 percent) compared to the previous year (2.6 percent). PBI projects, however, appear to be utilized less – exhibiting a lower CF in 2018 (6.4 percent), on average, than 2017 (8.1 percent).

Again, these metrics were developed from the period of available data for each project and each calendar year. A project may have received an upfront payment and begun normal operations in November of 2017 and the project CF would be calculated over that 2-month period. The CF for that same project, would be calculated for the entirety of 2018, where data was available and verifiable. Differences in performance across the two years could signal a change in operation or could represent differences in the time frame in which impacts were calculated for each year.

FIGURE 4-8: NONRESIDENTIAL CROSS-YEAR ROUNDTRIP EFFICIENCY COMPARISON (2017 TO 2018)

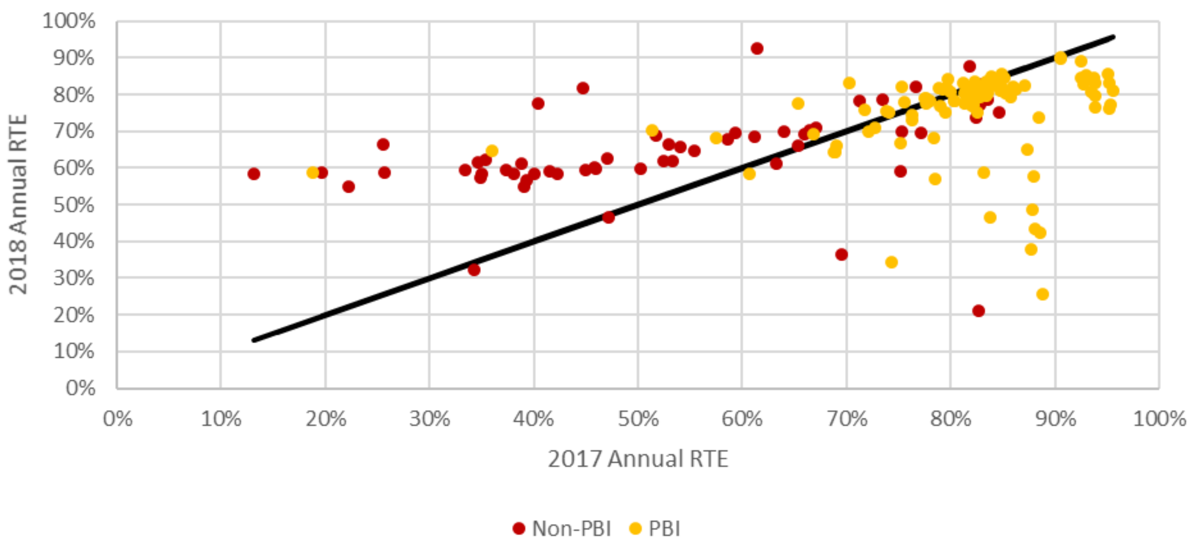
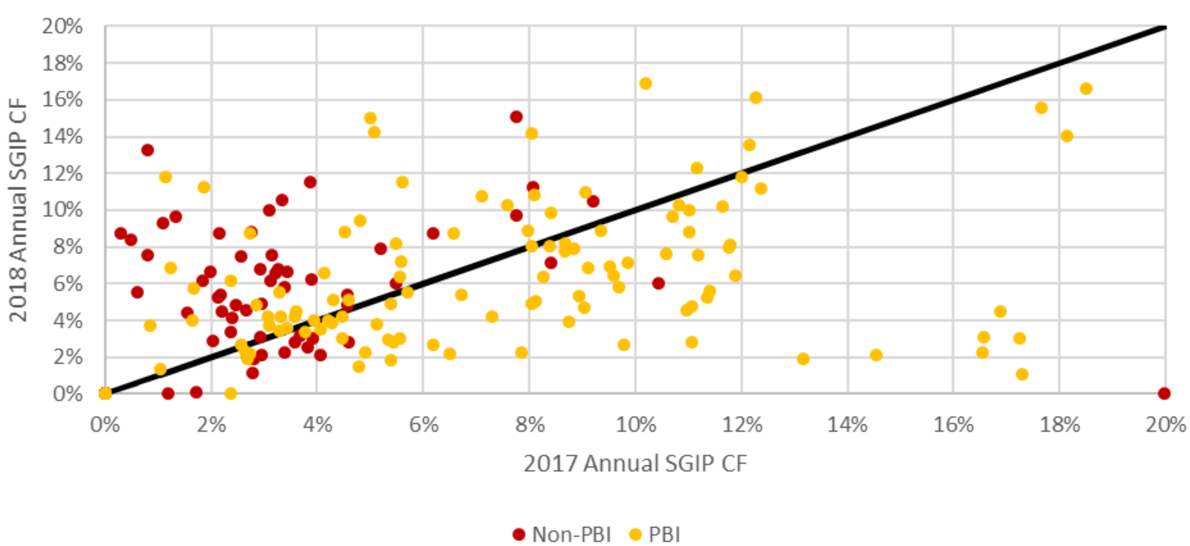


FIGURE 4-9: NONRESIDENTIAL CROSS-YEAR SGIP CAPACITY FACTOR COMPARISON (2017 TO 2018)



As presented above in Figure 4-7, residential storage systems that were evaluated in 2017 increased their utilization substantially in 2018. Storage systems were cycling daily, rather than just late in the year to meet program requirements of 52 cycles. This increase in utilization is evident in Figure 4-10 and Figure 4-11 where most projects increased their CF and RTE in 2018.

FIGURE 4-10: RESIDENTIAL CROSS-YEAR ROUNDTRIP EFFICIENCY COMPARISON (2017 TO 2018)

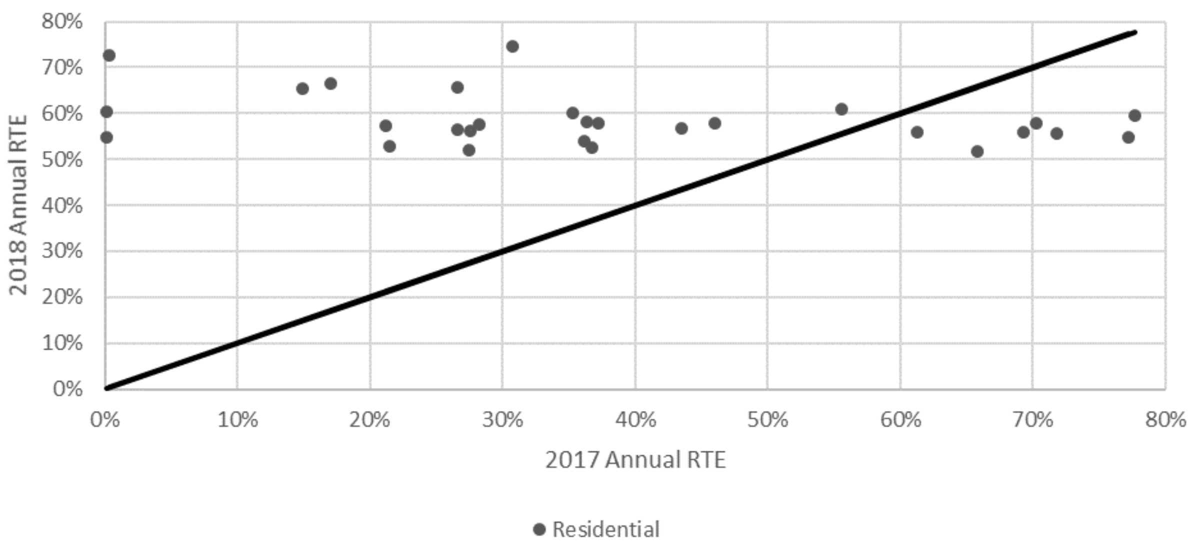
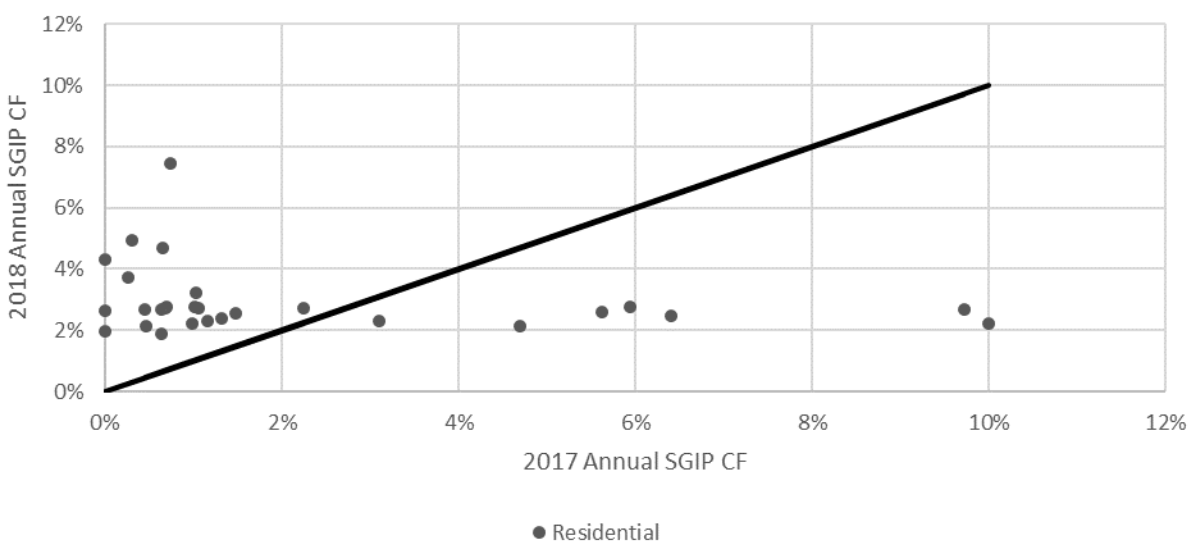


FIGURE 4-11: RESIDENTIAL CROSS-YEAR SGIP CAPACITY FACTOR COMPARISON (2017 TO 2018)



4.2.3 Influence of Parasitic Loads on Performance

The 2017 SGIP storage impact evaluation found much lower RTEs for non-PBI projects (51 percent) than for PBI projects (81 percent). Likewise, these systems were utilized less than PBI projects, with capacity factors generally ranging from 1.0 percent to 5.0 percent. One consequence of this utilization is the accumulation of standby losses and parasitic loads associated with system cooling, communications and other power electronic loads. The evaluation team found an increase in utilization and RTE for non-PBI projects in 2018, which would suggest an overall decrease in parasitic loads compared to the previous evaluation. We attempted to quantify the influence of these losses by classifying the storage dispatch into three general categories:

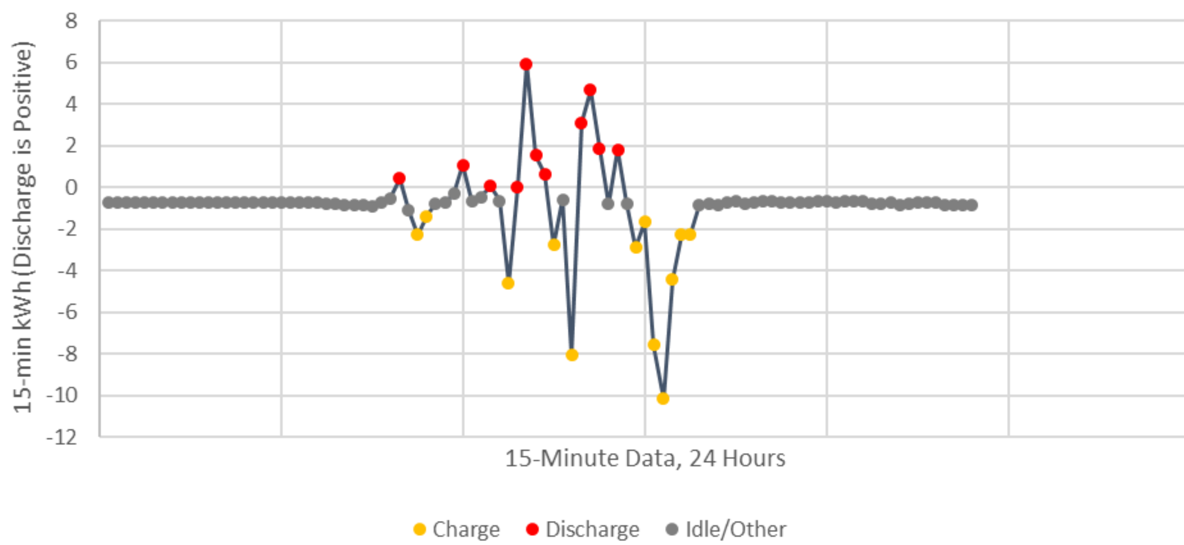
- Discharge – any 15-minute discharge (+) event
- Charge – any 15-minute charge (-) event not identified as an idle/other period
- Idle/Other – any 15-minute charge (-) event not identified as a charge period
  - Identify 15-minute charge (-) event when storage system is NOT discharging
  - Develop a frequency distribution of those 15-minute charge (-) events by project-specific storage system throughout the course of the year
  - Identify project-specific cut point where frequency distribution of charge kWh is obvious within the data[8]
  - Develop a weighted[9] average of all 15-minute charge observations below the cut point
  - These observations represented the parasitic load

Figure 4-12 presents a graphical representation of charge, discharge and idle/other designation. The 15-minute charge and discharge events are evident in the data. However, periods of inactivity (highlighted in gray) represent a small charge throughout the metering period. While the charge level is small at the 15-minute level, over the course of year, the impacts can become substantial, especially for a system that is under-utilized.

[8] For example, if 60 percent of charge events were 0.1 kWh (400 watts), 30 percent were 0.2 kWh (800 watts) and the next bin, 0.3 kWh (1,200 watts), represented 2 percent of all charge events, the cut point would be 0.2 kWh and below.

[9] The "weight" represents the total number of observations within each 15-minute charge kWh bin. In the above example, the weighted average would be ~ 0.133.

FIGURE 4-12: EXAMPLE CLASSIFICATION OF 15-MINUTE POWER KW CHARGE/DISCHARGE/IDLE



Nonresidential Parasitic Influence

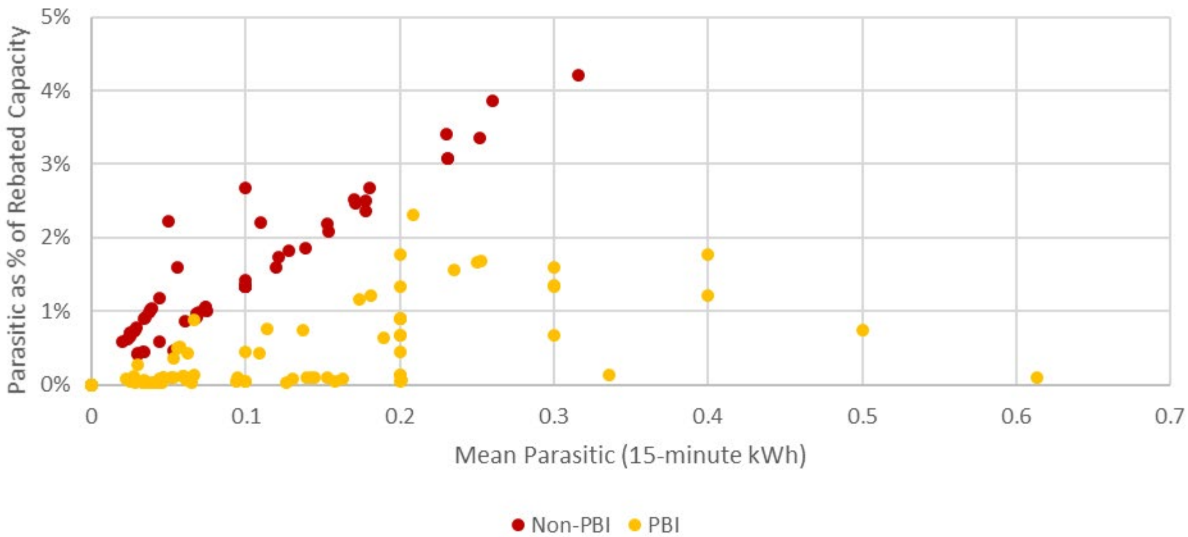
Figure 4-13 presents the average mean parasitic load for each project developed using the above methodology. The average parasitic load estimated at the 15-minute interval is represented on the horizontal axis and the percentage of rebated capacity each of those parasitics represent are conveyed on the vertical axis for non-PBI and PBI projects.

The average parasitic load for non-PBI ranges from zero to roughly 0.35 kWh at the 15-minute level and zero to roughly 0.6 kWh for PBI projects.[10] While there is considerable variability in the range of parasitics, the magnitude of those power draws relative to system rebated capacity are all within 0 percent to 4 percent for non-PBI projects and within 0 percent to 2 percent for PBI projects.[11] On average, this equates to 0.85 percent of rebated capacity for non-PBI systems and 0.20 percent for PBI systems.

[10] A 15-minute kWh load of 0.35 is equivalent to 1,400 watts of power at the same time interval.

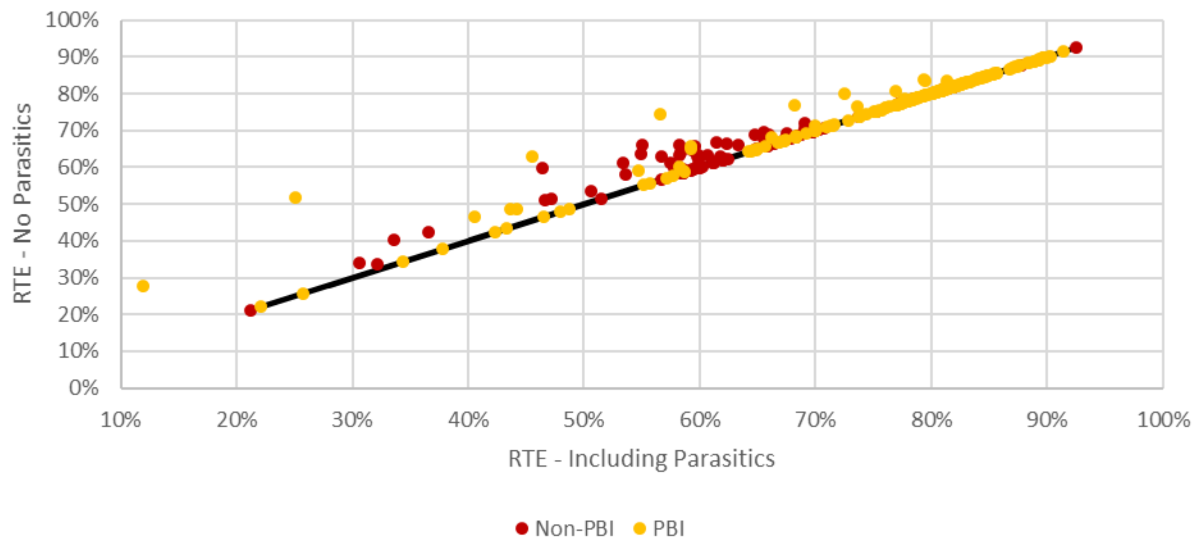
[11] These systems are rated as 2-hour batteries with inverters sometimes sized 2x the rebated capacity. The percentages on the vertical axis would be half of what is presented if the inverter size was twice the rebated capacity.

FIGURE 4-13: MEAN PARASTIC LOAD (KWH) AND MEAN PARASITIC LOAD AS A PERCENT OF REBATED CAPACITY (NONRESIDENTIAL)



We conducted an analysis on these data using the classification scheme discussed above to estimate the impact that these small parasitic loads can have on system performance. The 15-minute interval power output was set to zero for all Idle/Other observations. We then re-calculated the roundtrip efficiencies of nonresidential projects to assess the influence of those "idle" hours. The results of that analysis are presented below in Figure 4-14. The y-axis represents the system RTE with no parasitic loads and the x-axis represents the project RTE with the parasitic loads included (as observed). An observation on the black line means that the RTEs are identical – removing parasitic loads had no influence on the RTE of the system. This is mostly true for the larger PBI projects which are represented in yellow. However, for many of the non-PBI systems, removal of the parasitic loads would lead to an enhanced performance of the system. Projects in the 50 percent to 60 percent range would exhibit RTEs in the 60 percent to 70 percent range if the parasitic loads were removed.

FIGURE 4-14: INFLUENCE OF PARASITICS ON ROUNDTRIP EFFICIENCY (NONRESIDENTIAL PROJECTS)



4.3 CUSTOMER IMPACTS

Below we present the customer impacts developed from the sample of projects evaluated as part of the 2018 AES impact evaluation.

4.3.1 Nonresidential 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 peak and partial-peak hours (when retail energy rates are higher) and avoid charging until off-peak hours when rates are lower. Similarly, customers that are also 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 sub-hourly approximations of commercial rates within each of the three California electric IOUs. 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 (peak, partial-peak and off-peak).

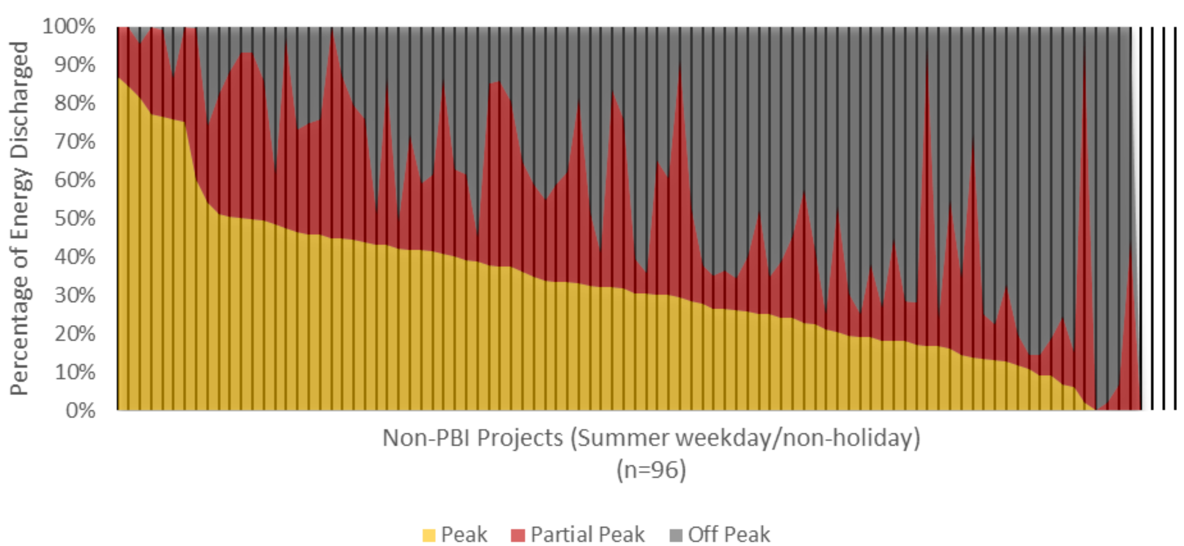
The evaluation team conducted several different but concurrent analyses using the above TOU period descriptions along with customer rate schedules. The remainder of this section presents those results in more detail:

- Overall storage dispatch behavior based on TOU period and project type (PBI and non-PBI);
- Overall storage dispatch behavior based on customer rate groups and project type (PBI and non-PBI); and
- Overall customer bill impacts ($/rebated kW) by rate group and project type.

Storage Dispatch Behavior by TOU Period and Project Type

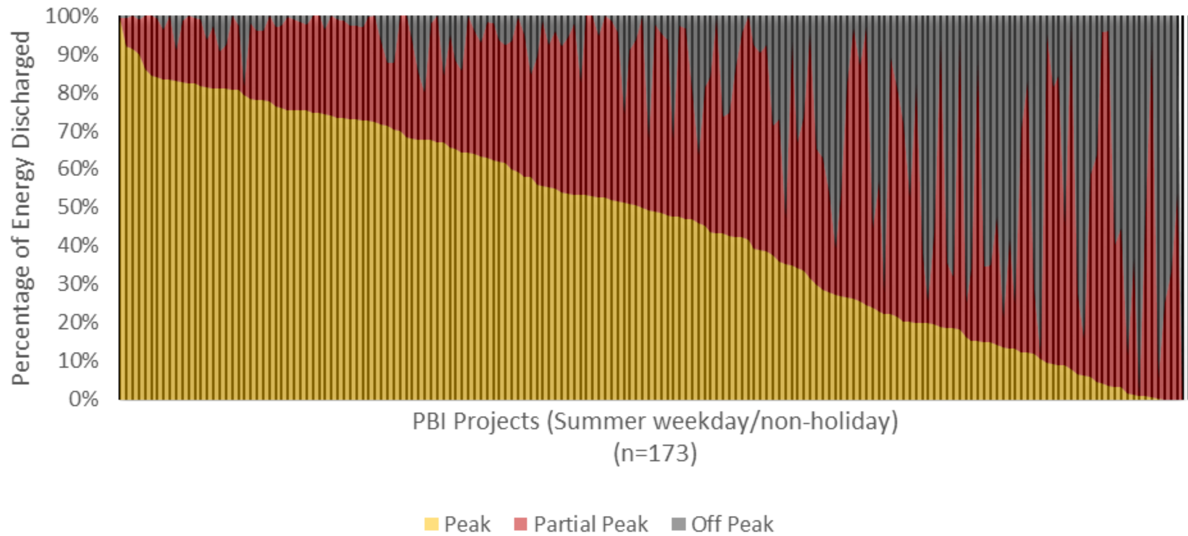
The evaluation team analyzed the extent to which customers utilize their storage systems for TOU energy arbitrage and peak demand reduction. We examined TOU energy dispatch by quantifying the magnitude of storage discharge by TOU period. Figure 4-15 and Figure 4-16 present the discharge behavior for our sample of 96 non-PBI nonresidential and 173 PBI nonresidential projects operating throughout the summer TOU.[12] Each vertical bar on the figures represents an individual project sorted by descending percentage of energy discharged during TOU peak periods.

FIGURE 4-15: 2018 SGIP NONRESIDENTIAL NON-PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD



[12] The blank bars to the far right of Figure 4-15 are sampled projects that were off-line or decommissioned in 2018, but had been conducting normal operations during the previous evaluation year.

FIGURE 4-16: 2018 SGIP NONRESIDENTIAL PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD



Customers are generally discharging during peak and partial-peak periods when retail energy rates are higher. However, a significant percentage of customers are also discharging during off-peak hours. This suggests that although customers are utilizing storage systems for TOU arbitrage, this might not be the main causal mechanism of dispatch behavior. Roughly 13 percent of non-PBI projects are discharging greater than 50 percent of their energy during peak TOU hours. Many of those projects are still discharging during partial-peak hours. However, a greater percentage of non-PBI projects (39 percent) are discharging more than 50 percent of their energy during off-peak TOU hours. Roughly 50 percent of PBI projects are discharging more than 50 percent of their energy during the IOU peak hours.[13]

We also examined the average net discharge during each of the summer and winter TOU periods for both project types. For non-PBI projects during the summer period, the average hourly net discharge (normalized by rebated kW capacity) is negative – which signifies charging – for all peak, partial-peak and off-peak hours. For PBI projects, the data suggest charging during the off-peak hours (-0.04 average hourly kW per rebated capacity (kW/kW)) and discharging during peak hours (0.05 kW/kW). A similar trend is evident in the winter months. The average net discharge during the partial-peak period in the winter is higher for PBI projects than in the summer. Given that there is no peak period for two IOUs in the winter months, these results are expected.

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[13] We will discuss how customer rate structures may have had an impact on energy discharge during peak periods in the following section.

FIGURE 4-17: HOURLY NET DISCHARGE KW PER REBATED KW BY SUMMER TOU PERIOD

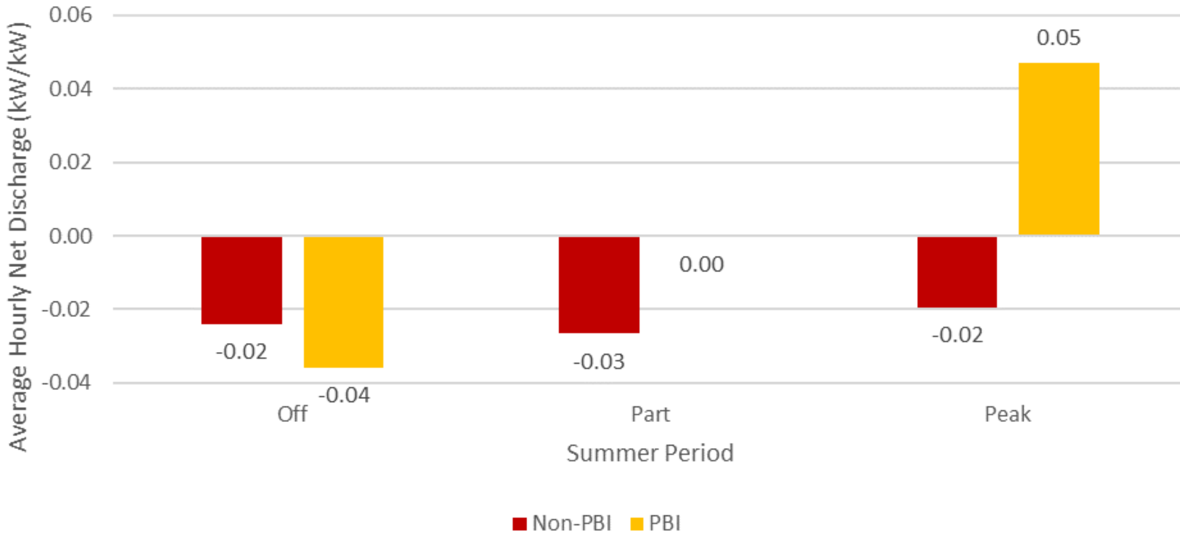
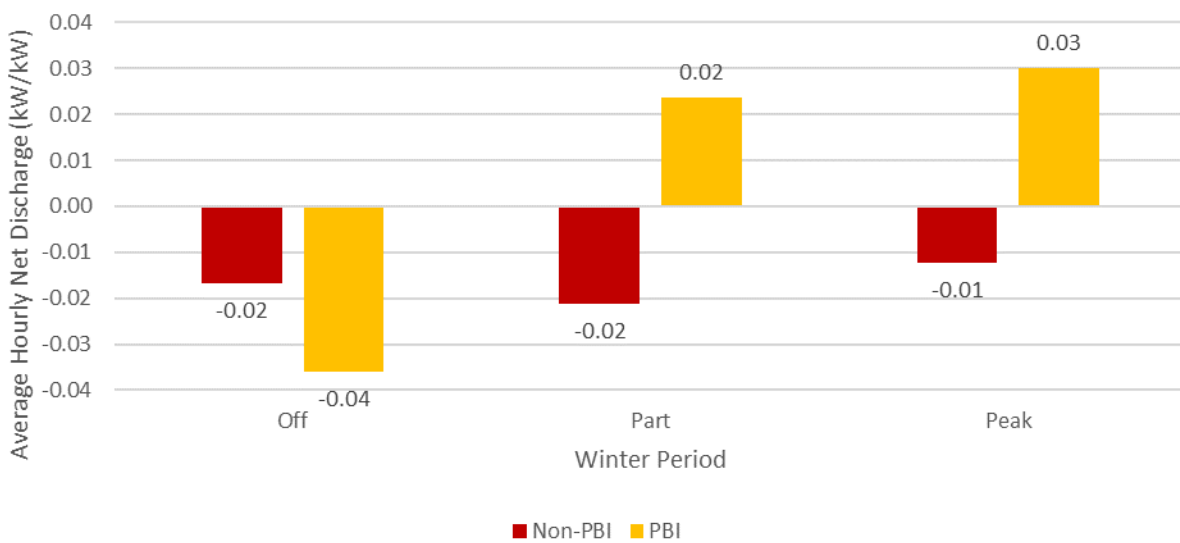


FIGURE 4-18: HOURLY NET DISCHARGE KW PER REBATED KW BY WINTER TOU PERIOD



We also examined the timing of aggregated storage dispatch to better understand how storage systems are being utilized throughout the year. We performed this analysis by taking the average hourly charge and discharge kW (normalized by rebated kW capacity) for each month and hour within the year for both PBI and non-PBI projects. Figure 4-19 and Figure 4-20 present the findings for PBI projects. Discharging is positive and is shown in green and charging is negative and is shown in red.

PBI projects illustrate a clear signature of charge and discharge throughout the year. In the early part of the year (January – April) the magnitude of storage discharge is more prevalent in the later afternoon and early evening. However, throughout summer months, discharge is distributed throughout more hours within the day. Average hourly kW charge is predominant in the late evening hours (from 10 pm to 2 am) throughout all months within the year.

FIGURE 4-19: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI PROJECTS

	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	0.030	0.030	0.029	0.027	0.030	0.018	0.025	0.026	0.027	0.027	0.023	0.026
1	0.033	0.033	0.027	0.025	0.027	0.028	0.034	0.031	0.026	0.026	0.023	0.037
2	0.031	0.030	0.032	0.031	0.030	0.025	0.038	0.040	0.033	0.028	0.026	0.039
3	0.033	0.037	0.034	0.032	0.031	0.025	0.037	0.034	0.027	0.027	0.023	0.032
4	0.034	0.037	0.020	0.012	0.013	0.012	0.022	0.034	0.025	0.027	0.025	0.030
5	0.008	0.011	0.014	0.013	0.016	0.014	0.027	0.042	0.030	0.032	0.027	0.031
6	0.019	0.024	0.022	0.018	0.022	0.017	0.026	0.041	0.037	0.040	0.039	0.045
7	0.020	0.020	0.022	0.025	0.023	0.017	0.022	0.030	0.027	0.026	0.036	0.046
8	0.015	0.015	0.018	0.022	0.028	0.022	0.026	0.030	0.023	0.023	0.022	0.027
9	0.025	0.023	0.030	0.036	0.033	0.029	0.031	0.035	0.026	0.027	0.027	0.027
10	0.031	0.032	0.034	0.036	0.036	0.034	0.035	0.042	0.031	0.033	0.030	0.027
11	0.037	0.036	0.036	0.038	0.040	0.039	0.045	0.053	0.042	0.043	0.035	0.029
12	0.044	0.041	0.041	0.041	0.041	0.040	0.048	0.053	0.044	0.046	0.038	0.032
13	0.046	0.041	0.040	0.037	0.040	0.039	0.072	0.067	0.042	0.046	0.041	0.031
14	0.037	0.036	0.037	0.033	0.042	0.042	0.080	0.071	0.043	0.062	0.046	0.032
15	0.033	0.034	0.043	0.045	0.058	0.061	0.105	0.094	0.065	0.097	0.078	0.071
16	0.042	0.040	0.046	0.043	0.054	0.054	0.103	0.091	0.064	0.107	0.109	0.096
17	0.051	0.052	0.056	0.049	0.034	0.027	0.036	0.038	0.042	0.057	0.112	0.101
18	0.056	0.056	0.074	0.074	0.056	0.037	0.052	0.053	0.051	0.076	0.060	0.055
19	0.073	0.066	0.073	0.071	0.065	0.042	0.059	0.063	0.052	0.077	0.073	0.071
20	0.074	0.066	0.049	0.040	0.042	0.025	0.039	0.049	0.046	0.045	0.074	0.076
21	0.033	0.031	0.034	0.033	0.057	0.043	0.068	0.062	0.052	0.050	0.052	0.063
22	0.045	0.041	0.039	0.038	0.038	0.033	0.035	0.031	0.020	0.031	0.048	0.056
23	0.046	0.041	0.029	0.024	0.027	0.021	0.026	0.023	0.019	0.022	0.031	0.040

FIGURE 4-20: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI PROJECTS

	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	-0.154	-0.145	-0.135	-0.122	-0.120	-0.094	-0.140	-0.130	-0.093	-0.121	-0.153	-0.148
1	-0.131	-0.128	-0.107	-0.088	-0.085	-0.054	-0.103	-0.087	-0.065	-0.094	-0.128	-0.127
2	-0.102	-0.098	-0.078	-0.062	-0.066	-0.046	-0.080	-0.070	-0.058	-0.073	-0.102	-0.107
3	-0.073	-0.075	-0.058	-0.047	-0.051	-0.039	-0.063	-0.067	-0.054	-0.060	-0.081	-0.094
4	-0.055	-0.059	-0.043	-0.035	-0.036	-0.040	-0.070	-0.059	-0.049	-0.051	-0.064	-0.075
5	-0.039	-0.040	-0.027	-0.021	-0.024	-0.021	-0.032	-0.051	-0.039	-0.039	-0.046	-0.057
6	-0.018	-0.017	-0.016	-0.017	-0.018	-0.020	-0.027	-0.037	-0.031	-0.035	-0.035	-0.042
7	-0.015	-0.017	-0.020	-0.022	-0.017	-0.020	-0.036	-0.035	-0.031	-0.036	-0.039	-0.039
8	-0.019	-0.024	-0.024	-0.021	-0.025	-0.030	-0.055	-0.049	-0.044	-0.056	-0.049	-0.049
9	-0.030	-0.031	-0.030	-0.028	-0.029	-0.029	-0.047	-0.049	-0.043	-0.052	-0.058	-0.067
10	-0.028	-0.029	-0.030	-0.029	-0.028	-0.026	-0.035	-0.042	-0.038	-0.048	-0.055	-0.065
11	-0.025	-0.025	-0.024	-0.022	-0.024	-0.022	-0.027	-0.033	-0.030	-0.033	-0.045	-0.054
12	-0.020	-0.018	-0.020	-0.020	-0.022	-0.019	-0.023	-0.030	-0.025	-0.023	-0.028	-0.038
13	-0.017	-0.016	-0.019	-0.019	-0.020	-0.020	-0.024	-0.030	-0.025	-0.026	-0.025	-0.028
14	-0.023	-0.020	-0.021	-0.021	-0.022	-0.021	-0.023	-0.033	-0.028	-0.028	-0.025	-0.026
15	-0.025	-0.022	-0.021	-0.020	-0.019	-0.018	-0.020	-0.028	-0.023	-0.025	-0.027	-0.024
16	-0.022	-0.020	-0.024	-0.024	-0.024	-0.024	-0.022	-0.031	-0.026	-0.027	-0.023	-0.025
17	-0.020	-0.018	-0.025	-0.027	-0.029	-0.031	-0.033	-0.043	-0.033	-0.034	-0.023	-0.023
18	-0.021	-0.021	-0.021	-0.021	-0.022	-0.025	-0.029	-0.032	-0.026	-0.030	-0.028	-0.023
19	-0.019	-0.018	-0.017	-0.020	-0.021	-0.023	-0.027	-0.030	-0.027	-0.028	-0.027	-0.023
20	-0.018	-0.016	-0.044	-0.062	-0.046	-0.043	-0.044	-0.053	-0.048	-0.059	-0.033	-0.026
21	-0.049	-0.045	-0.080	-0.094	-0.114	-0.081	-0.079	-0.081	-0.066	-0.093	-0.061	-0.057
22	-0.122	-0.114	-0.123	-0.136	-0.154	-0.132	-0.179	-0.175	-0.133	-0.153	-0.084	-0.080
23	-0.139	-0.127	-0.141	-0.150	-0.157	-0.113	-0.170	-0.169	-0.134	-0.157	-0.154	-0.147

Non-PBI projects, conversely, exhibit more variability with regards to charging and discharging throughout the day. Figure 4-21 and Figure 4-22 convey these results. For non-PBI projects, the magnitude of charge and discharge kW within the same hours are very similar throughout the hours of the day. While the PBI data suggest that customers are discharging during the day and throughout the early evening and charging later in the evening, non-PBI systems are constantly cycling. This suggests that systems are being utilized to perform peak demand reduction.

Non-PBI systems also exhibit a clear signature of charging and discharging throughout the early morning hours (12 am through 3 am) during the latter months of the year. These patterns were confirmed when reviewing project-specific data and off-peak discharging percentages shown in Figure 4-15. There appear to be no discernible reasons for this pattern of charge/discharge during the morning hours from a bill savings perspective. However, this behavior does increase the utilization of the system and the RTE.

Itron

FIGURE 4-21: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI PROJECTS

	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	0.004	0.002	0.007	0.006	0.054	0.112	0.128	0.067	0.083	0.120	0.074	0.135
1	0.007	0.008	0.003	0.001	0.026	0.075	0.161	0.208	0.210	0.127	0.075	0.157
2	0.003	0.001	0.001	0.001	0.019	0.024	0.041	0.100	0.138	0.128	0.096	0.154
3	0.002	0.001	0.001	0.001	0.016	0.012	0.010	0.039	0.085	0.064	0.055	0.092
4	0.003	0.001	0.006	0.010	0.018	0.008	0.009	0.016	0.053	0.030	0.038	0.067
5	0.014	0.006	0.010	0.034	0.058	0.033	0.036	0.045	0.067	0.056	0.052	0.069
6	0.021	0.016	0.010	0.030	0.057	0.034	0.036	0.049	0.058	0.049	0.046	0.051
7	0.016	0.013	0.009	0.020	0.031	0.026	0.027	0.027	0.029	0.023	0.026	0.029
8	0.023	0.014	0.009	0.014	0.036	0.032	0.035	0.033	0.038	0.030	0.019	0.022
9	0.027	0.020	0.015	0.021	0.039	0.035	0.045	0.035	0.043	0.035	0.023	0.026
10	0.034	0.022	0.015	0.023	0.040	0.040	0.051	0.038	0.042	0.033	0.027	0.028
11	0.031	0.022	0.020	0.025	0.046	0.048	0.052	0.042	0.044	0.035	0.028	0.030
12	0.035	0.027	0.021	0.024	0.043	0.050	0.062	0.045	0.047	0.038	0.032	0.028
13	0.035	0.030	0.023	0.026	0.044	0.049	0.061	0.041	0.043	0.041	0.035	0.028
14	0.035	0.028	0.020	0.024	0.040	0.043	0.053	0.041	0.043	0.036	0.030	0.028
15	0.029	0.026	0.027	0.028	0.053	0.059	0.057	0.059	0.059	0.052	0.035	0.027
16	0.038	0.041	0.028	0.026	0.049	0.051	0.054	0.055	0.057	0.040	0.038	0.041
17	0.042	0.034	0.021	0.018	0.038	0.043	0.035	0.035	0.041	0.034	0.037	0.040
18	0.035	0.029	0.024	0.017	0.032	0.030	0.020	0.028	0.046	0.056	0.030	0.031
19	0.025	0.022	0.021	0.015	0.031	0.034	0.027	0.027	0.033	0.025	0.048	0.063
20	0.020	0.017	0.014	0.008	0.015	0.011	0.010	0.017	0.029	0.038	0.025	0.034
21	0.009	0.008	0.005	0.002	0.012	0.010	0.070	0.039	0.073	0.105	0.023	0.028
22	0.005	0.006	0.004	0.002	0.007	0.006	0.030	0.028	0.057	0.056	0.049	0.070
23	0.004	0.003	0.002	0.001	0.006	0.006	0.041	0.038	0.100	0.118	0.037	0.051

FIGURE 4-22: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI PROJECTS

	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	-0.027	-0.021	-0.018	-0.019	-0.044	-0.045	-0.071	-0.038	-0.093	-0.123	-0.087	-0.123
1	-0.027	-0.023	-0.016	-0.016	-0.054	-0.129	-0.158	-0.133	-0.141	-0.170	-0.090	-0.160
2	-0.022	-0.018	-0.011	-0.013	-0.042	-0.084	-0.168	-0.196	-0.198	-0.148	-0.101	-0.189
3	-0.019	-0.015	-0.010	-0.012	-0.035	-0.039	-0.059	-0.140	-0.183	-0.150	-0.117	-0.185
4	-0.017	-0.014	-0.010	-0.012	-0.033	-0.031	-0.032	-0.059	-0.125	-0.094	-0.080	-0.132
5	-0.017	-0.014	-0.012	-0.016	-0.035	-0.024	-0.024	-0.035	-0.080	-0.058	-0.064	-0.103
6	-0.023	-0.020	-0.017	-0.023	-0.035	-0.026	-0.031	-0.032	-0.055	-0.039	-0.050	-0.072
7	-0.035	-0.025	-0.018	-0.024	-0.032	-0.025	-0.028	-0.030	-0.038	-0.029	-0.037	-0.046
8	-0.028	-0.024	-0.015	-0.023	-0.046	-0.036	-0.042	-0.042	-0.049	-0.042	-0.032	-0.035
9	-0.042	-0.030	-0.018	-0.034	-0.062	-0.053	-0.054	-0.057	-0.063	-0.057	-0.048	-0.052
10	-0.042	-0.032	-0.021	-0.041	-0.068	-0.057	-0.061	-0.064	-0.075	-0.065	-0.054	-0.056
11	-0.050	-0.036	-0.024	-0.043	-0.072	-0.068	-0.069	-0.070	-0.077	-0.069	-0.057	-0.059
12	-0.049	-0.037	-0.027	-0.043	-0.074	-0.068	-0.070	-0.073	-0.079	-0.070	-0.056	-0.058
13	-0.051	-0.038	-0.029	-0.043	-0.073	-0.073	-0.076	-0.073	-0.081	-0.074	-0.059	-0.057
14	-0.050	-0.043	-0.028	-0.049	-0.079	-0.071	-0.076	-0.071	-0.077	-0.077	-0.061	-0.057
15	-0.056	-0.045	-0.029	-0.037	-0.059	-0.056	-0.062	-0.057	-0.063	-0.062	-0.051	-0.051
16	-0.048	-0.043	-0.029	-0.038	-0.064	-0.065	-0.065	-0.061	-0.067	-0.058	-0.049	-0.044
17	-0.046	-0.046	-0.033	-0.040	-0.067	-0.067	-0.082	-0.072	-0.078	-0.060	-0.049	-0.047
18	-0.048	-0.049	-0.035	-0.035	-0.062	-0.070	-0.077	-0.070	-0.067	-0.055	-0.052	-0.053
19	-0.046	-0.041	-0.031	-0.031	-0.053	-0.061	-0.061	-0.053	-0.063	-0.048	-0.045	-0.050
20	-0.043	-0.037	-0.036	-0.034	-0.047	-0.050	-0.052	-0.047	-0.055	-0.065	-0.044	-0.049
21	-0.038	-0.033	-0.033	-0.024	-0.051	-0.050	-0.094	-0.079	-0.092	-0.119	-0.064	-0.074
22	-0.036	-0.032	-0.022	-0.022	-0.040	-0.033	-0.087	-0.064	-0.095	-0.098	-0.072	-0.088
23	-0.029	-0.028	-0.019	-0.017	-0.027	-0.023	-0.066	-0.068	-0.113	-0.117	-0.060	-0.065

We then examined the impact of storage discharge on monthly demand. Hourly impacts provide insight into the performance of the system during TOU periods, but 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 4-23 and Figure 4-24 convey those results. For both non-PBI and PBI projects, storage dispatch resulted in significant reductions in monthly peak demand. For non-PBI projects, the evaluation team identified many projects that appeared not to be operating during the latter half of February through early April. This pattern is evident in the figure below. For PBI projects, the patterns are similar, however, the percentage of projects reducing monthly peak demand is 70 percent to 85 percent throughout the year.

FIGURE 4-23: MONTHLY PEAK DEMAND IMPACT FOR NON-PBI PROJECTS

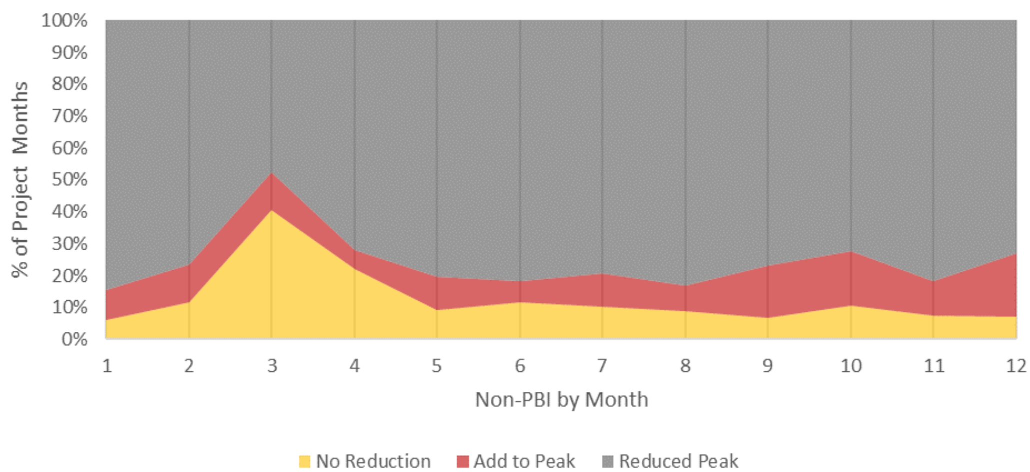
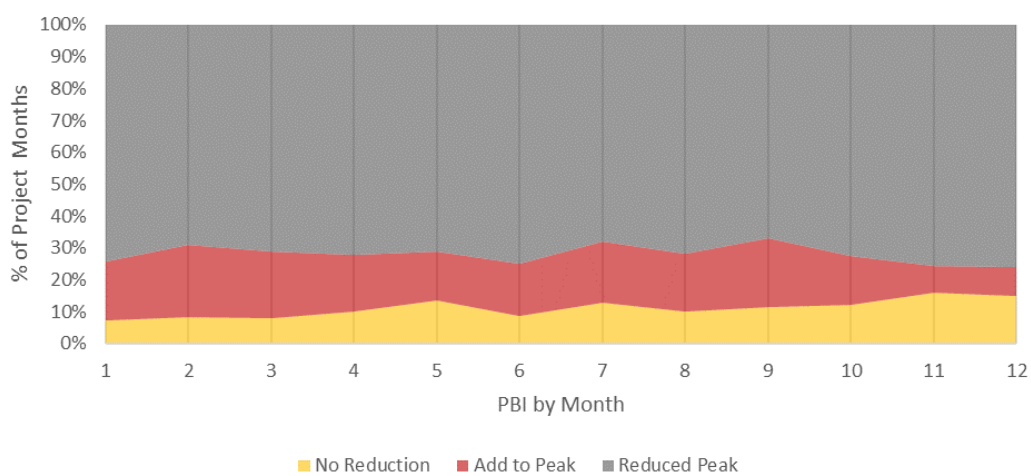


FIGURE 4-24: MONTHLY PEAK DEMAND IMPACT FOR PBI PROJECTS



While storage systems are providing customer peak demand benefits, we also analyzed the utilization of the system to execute those benefits. We examined the monthly peak demand reductions, relative to the rebated capacity of the system and the overall reduction in demand. Figure 4-25 conveys the former analysis. Throughout the year, non-PBI projects are reducing monthly demand as a percentage of rebated capacity more than PBI projects. The average customer peak demand reduction is 42 percent of SGIP rebated capacity for non-PBI projects and 17 percent for PBI projects.

FIGURE 4-25: MONTHLY PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

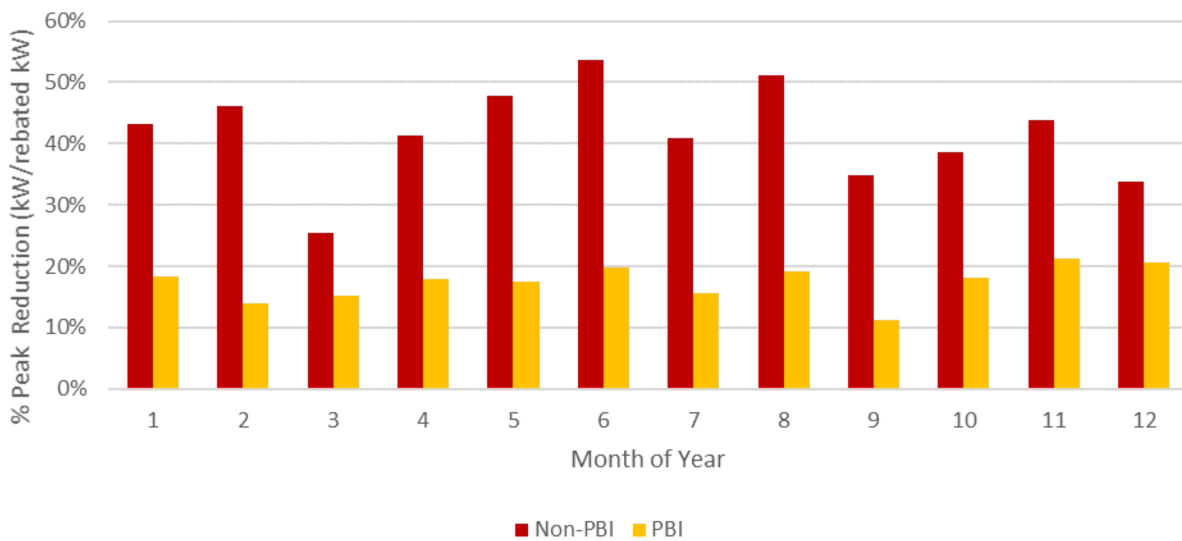


Figure 4-26 conveys the monthly average peak demand reduction as a percentage of the monthly avoided peak. In other words, if a customer's monthly peak demand would have been 100 kW in the absence of the storage system and they reduced peak demand by 10 kW with storage, then the customer reduced their peak demand by 10 percent. On average, PBI customers are reducing their peak demand 8 percent and non-PBI customers are reducing their peak demand by 6 percent.

FIGURE 4-26: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW)

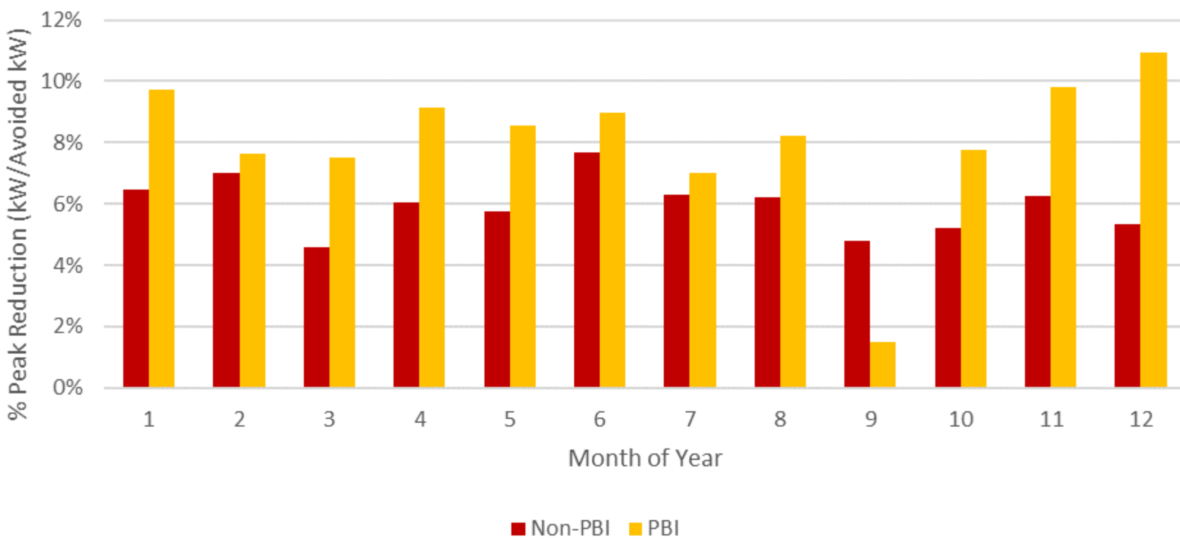
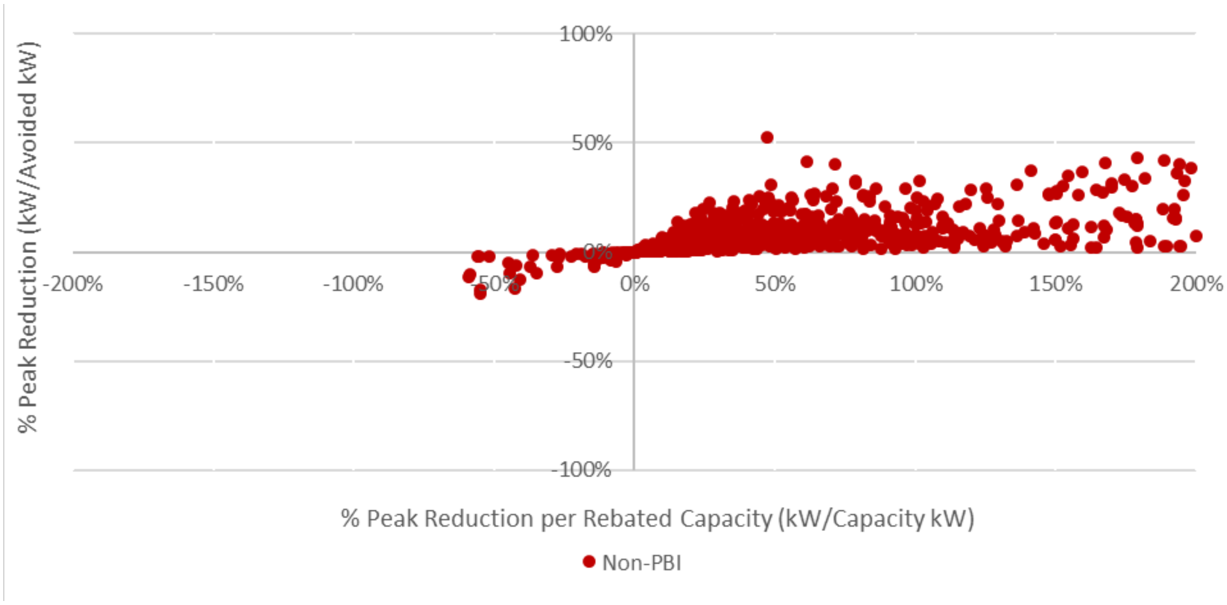


Figure 4-27 and Figure 4-28 disaggregate the data provided in the above figures for each project-month. The horizontal axis represents the monthly peak demand reduction, as a percentage of rebated capacity, for each project-month and the vertical axis represents the monthly peak demand reduction for each project relative to their avoided peak demand for that month.

While the average peak demand reduction is 41 percent of SGIP rebated capacity for non-PBI projects, the distribution by project-month ranges from as high as 200 percent to as low as a 50 percent increase in monthly demand.[14] Non-PBI projects are generally smaller relative to the load they service, so they are reducing their peak monthly demand from as high as 50 percent to as low as -20 percent.

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

FIGURE 4-27: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) PER NON-PBI PROJECT



Larger PBI systems are utilizing a smaller 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 like those of non-PBI projects. It's important to note that several observations within these figures indicate an increase in peak demand from storage. These observations are by project-month, so twelve monthly observations for one project could be negative. An example of this is a large PBI project co-located with PV. The storage system discharges regularly throughout hours of PV generation and charges overnight. The storage discharge contributes to a net export of energy throughout the PV generation (or to satisfy facility load) and the charging overnight increases their monthly demand (in the absence of the storage system).

FIGURE 4-28: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) PER PBI PROJECT

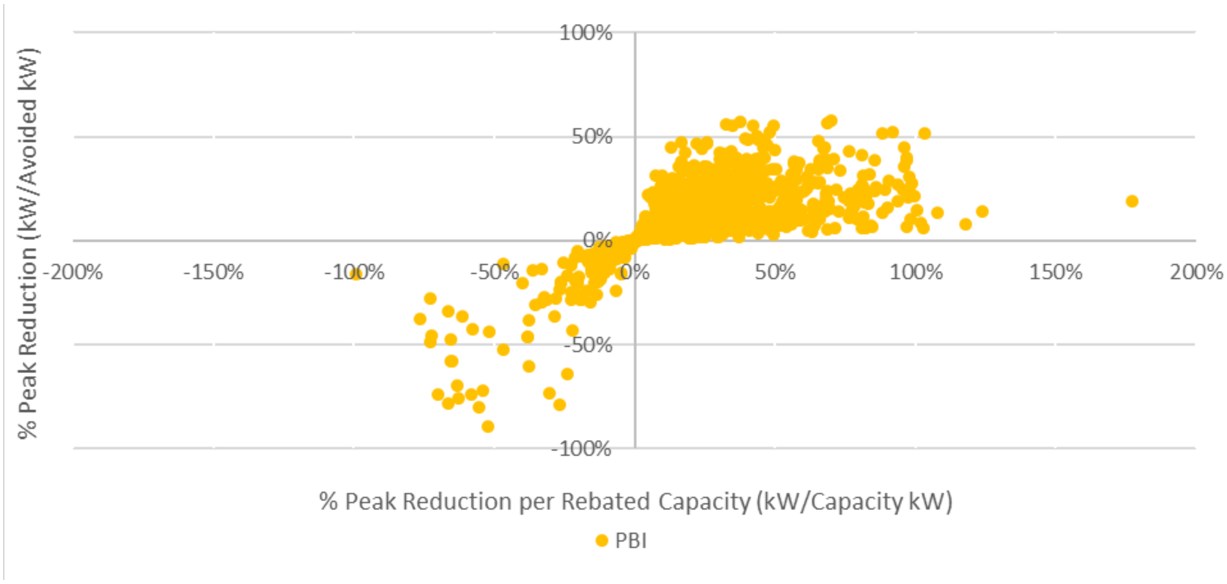


Figure 4-29 and Figure 4-30 present the rebated capacity for each system (non-PBI and PBI, respectively) relative to the size of facility load. In other words, if a storage system is sized at 50 kW (rebated capacity) and the maximum 15-minute load at that facility would have been 100 kW throughout the year, the system size relative to load would be 50 percent. Non-PBI systems, on average, are sized from 100 percent to close to 1 percent of facility load. Many PBI projects, however, are sized much larger than the load they are servicing and are discharging less power over a longer duration.

FIGURE 4-29: PERCENT CAPACITY (KW) PER MAX ANNUAL AVOIDED PEAK (KW) FOR NON-PBI PROJECTS

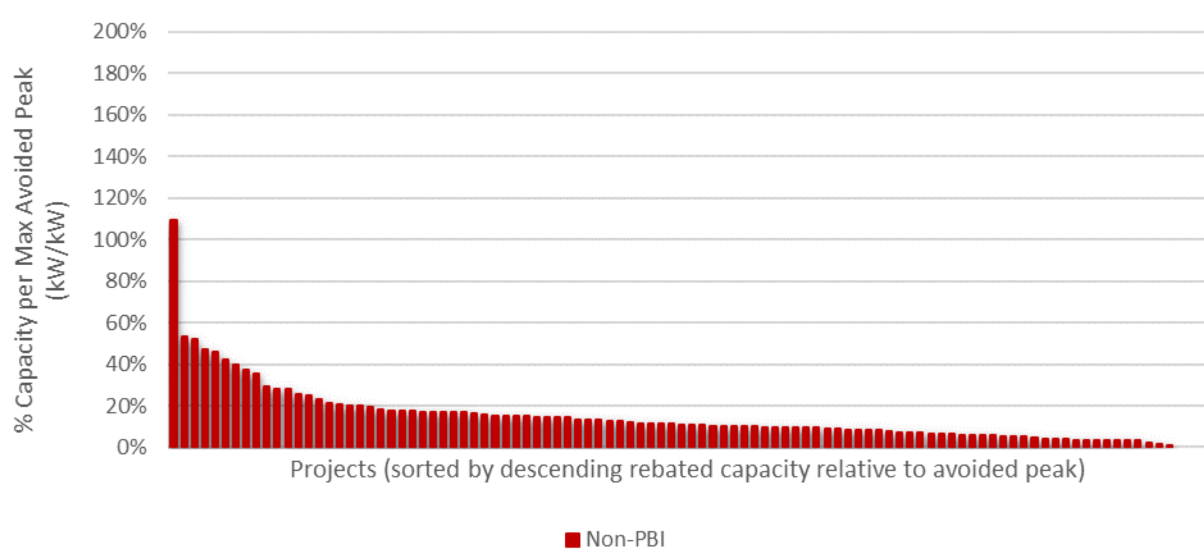
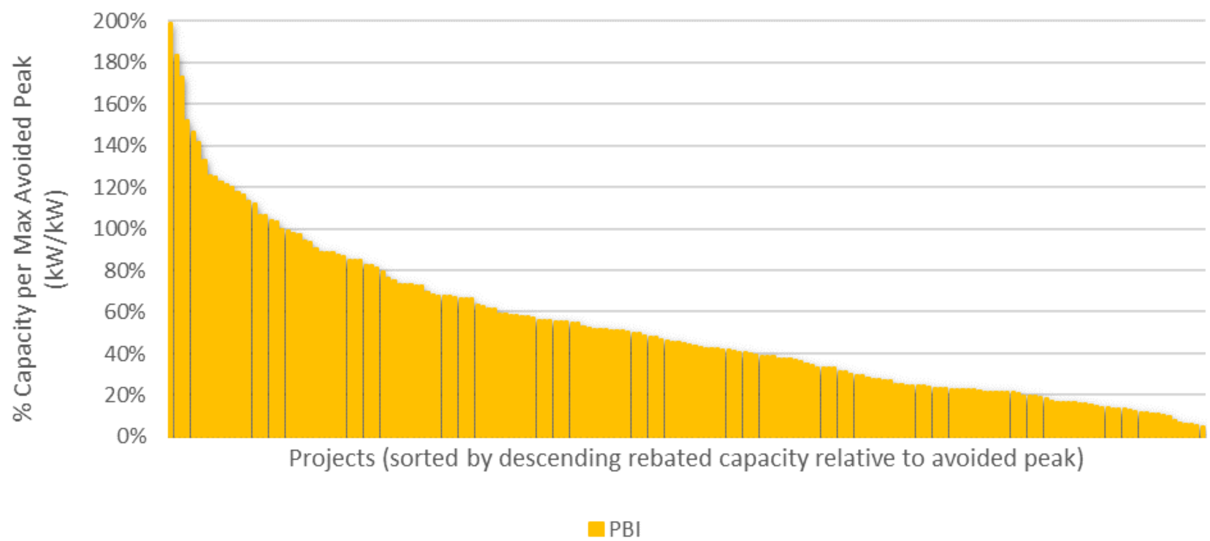


FIGURE 4-30: PERCENT CAPACITY (KW) PER MAX ANNUAL AVOIDED PEAK (KW) FOR PBI PROJECTS



Overall Storage Dispatch Behavior by Customer Rate Group and Project Type

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 more than 25 unique customer rates from the sample of projects, so we grouped projects into two distinct rate groups. All nonresidential customers in the SGIP sample with a verified rate schedule were on some type of TOU schedule:

- TOU Energy Only Rate (only 1 non-PBI and 6 PBI customers were on this rate type)
  - This rate group includes customers on an energy only tariff. They were charged a different energy rate ($/kWh) depending on the period (off-peak, partial-peak or peak hours) and season (winter or summer).
- TOU Energy with Demand Charge (all others were assessed some type of demand charge)
  - This rate group includes customers on a TOU energy rate as well as a monthly demand charge ($/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 (off-peak, partial-peak or peak hours) and season (winter and/or summer).

Overall Customer Bill Savings ($/kW) by Rate Group and Project Type for Nonresidential Customers

We combined the energy rates charged during each of the TOU periods and compared energy consumption with storage versus calculated energy consumption in the absence of storage to develop bill impact estimates for customers. For customers with demand charges, we further estimated the reduction (or increase) in peak demand on a monthly level and during specific TOU periods and calculated demand savings (or costs) 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 4-31 presents those results for PBI and non-PBI projects by rate group. The vertical axis represents the average monthly savings (or cost) in dollars, normalized by rebated capacity.

PBI and non-PBI customers incurred energy costs, on average, by utilizing their storage systems. However, they realized significant savings by optimizing their storage to reduce peak and/or monthly demand. Bill impacts for customers on a TOU energy only rate are not presented below given small sample sizes. Overall, the sample of PBI and non-PBI customers realized bill savings in 2018 (Figure 4-32).

FIGURE 4-31: NONRESIDENTIAL MONTHLY CUSTOMER BILL SAVINGS ($/KW) BY RATE GROUP AND PBI/NON-PBI

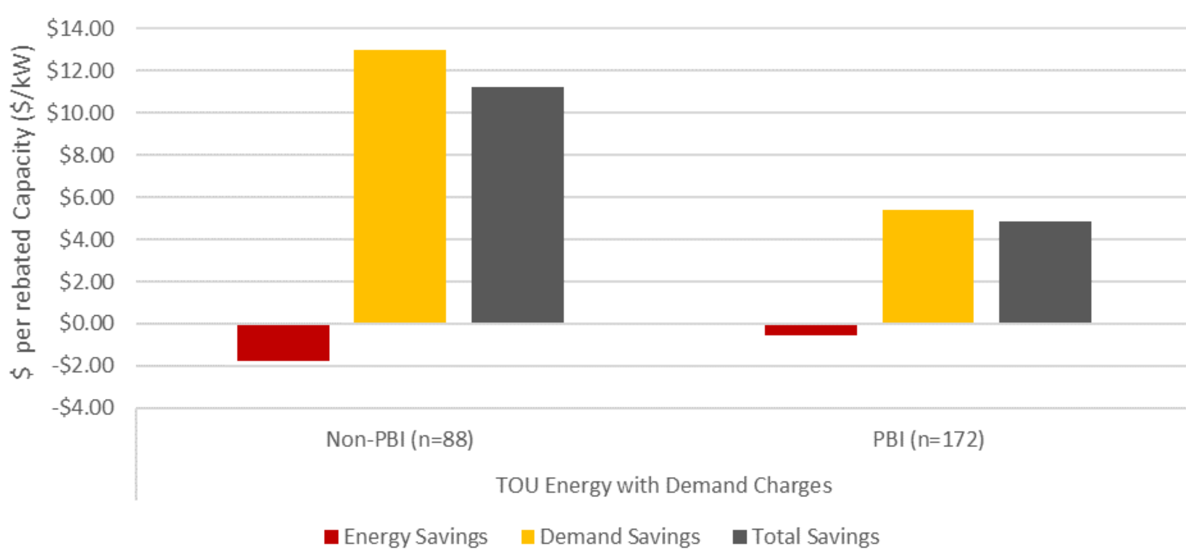
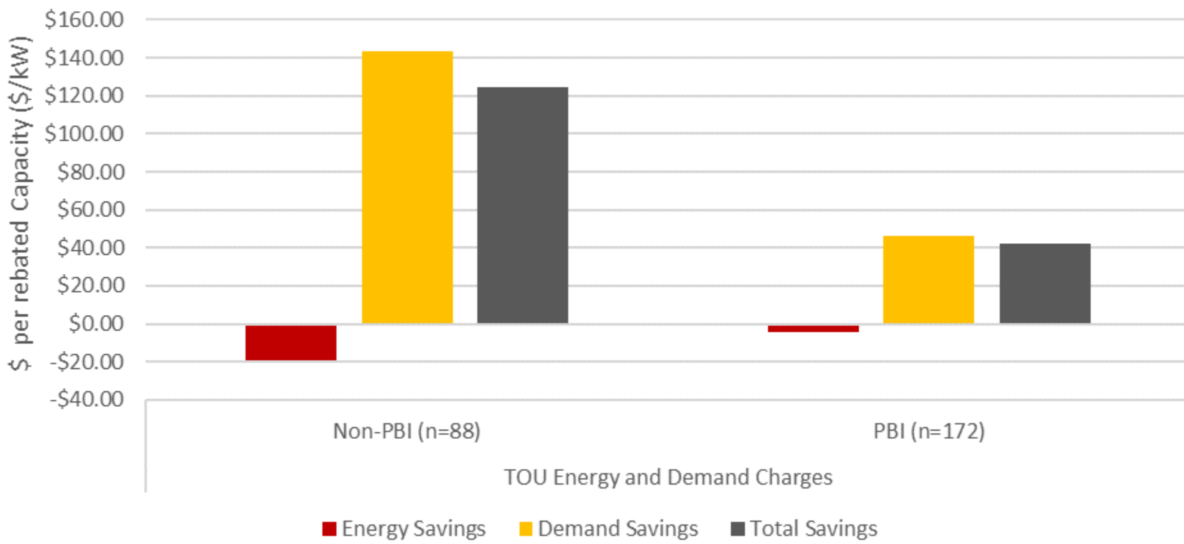


FIGURE 4-32: NONRESIDENTIAL OVERALL CUSTOMER BILL SAVINGS ($/KW) BY RATE GROUP AND PBI/NON-PBI



4.3.2 Residential Customer Impacts

Storage Dispatch Behavior

The evaluation team analyzed the extent to which residential customers utilize their storage systems for TOU energy arbitrage. Of the 284 sampled residential projects, the evaluation team was able to confirm that 201 of them were on a TOU rate at some point throughout 2018. We examined TOU energy dispatch by quantifying the magnitude of storage discharge by TOU period. Unlike nonresidential TOU periods, which are generally defined by IOU, residential TOU periods are defined by the specific rate the customer is on. The on-peak for an electric vehicle (EV) TOU rate will differ from a TOU-A or TOU-B rate. Figure 4-33 and Figure 4-34 present the discharge behavior for sampled residential projects on a TOU rate operating throughout the summer and winter TOU periods, respectively. Each vertical bar on the figures represents an individual project sorted by descending percentage of energy discharged during that customer's TOU peak periods.

FIGURE 4-33: 2018 SGIP RESIDENTIAL PROJECT DISCHARGE BY SUMMER TOU PERIOD

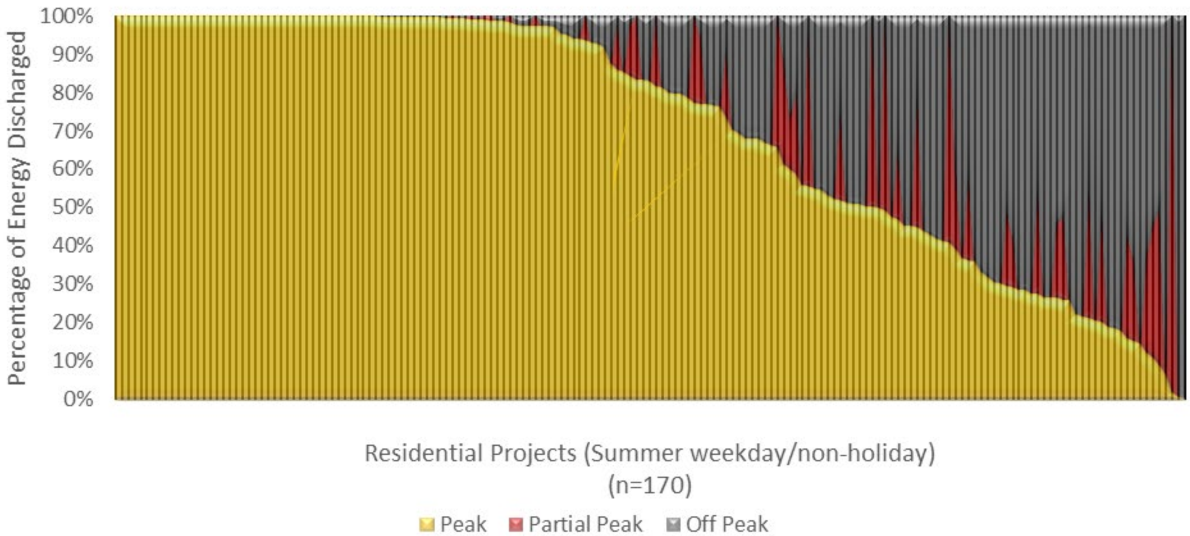
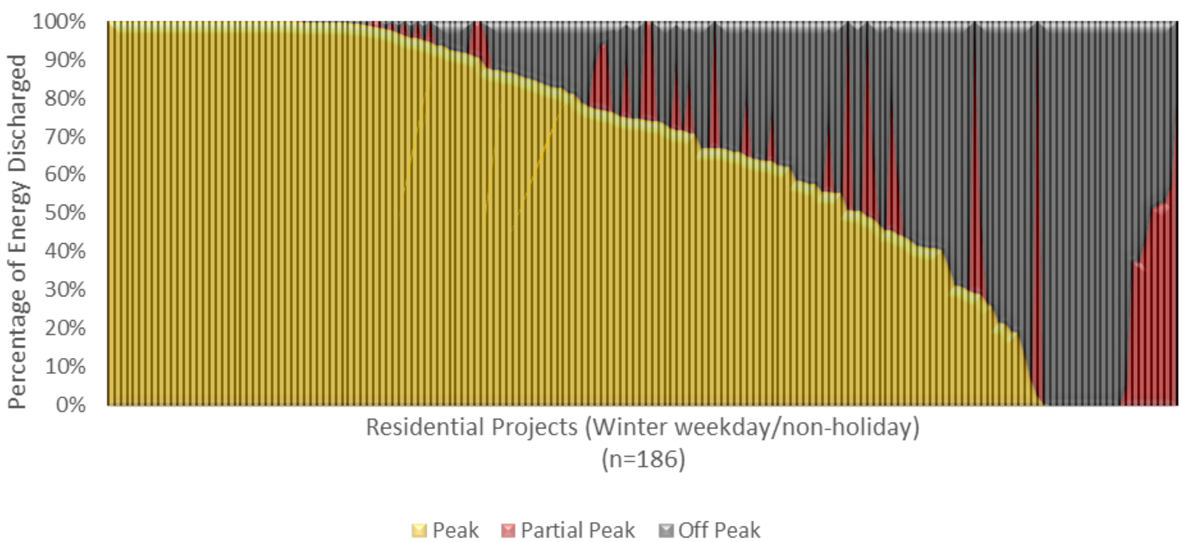


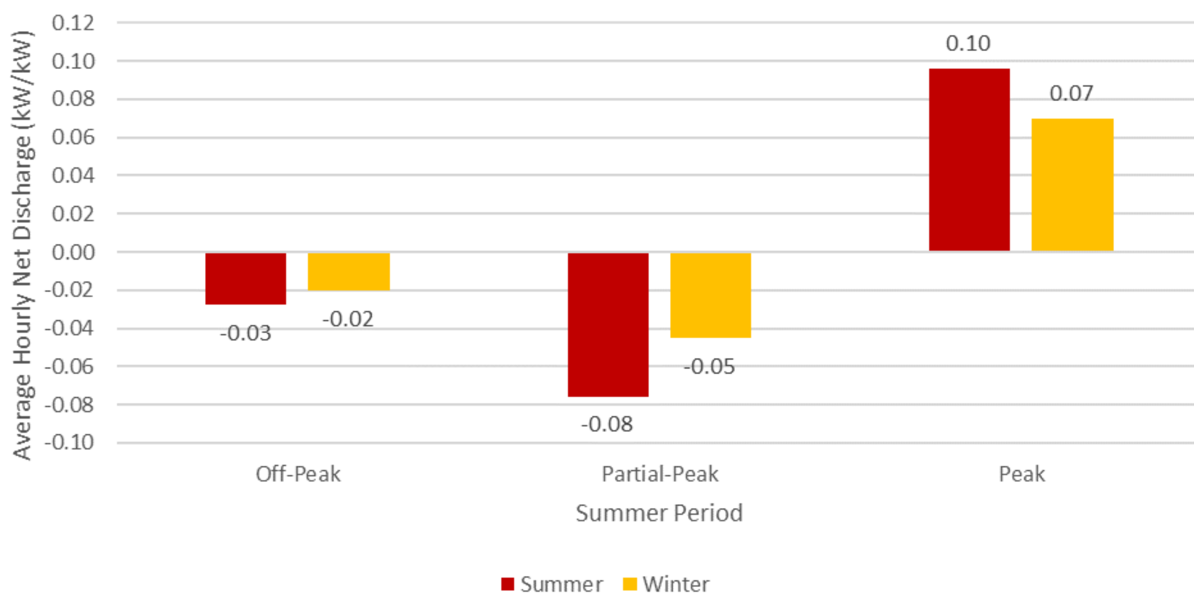
FIGURE 4-34: 2018 SGIP RESIDENTIAL PROJECT DISCHARGE BY WINTER TOU PERIOD



Residential customers are discharging during peak and partial-peak TOU periods much more often than nonresidential projects. Over 70 percent of projects were discharging greater than 50 percent or more of their energy during the summer peak period. Seventy-eight projects discharged 100 percent of their energy during the summer peak period.[15] A similar pattern is evident in winter months.

We also examined the average net discharge during each of the summer and winter TOU periods for residential projects. During the summer and winter periods, the average hourly net discharge (normalized by rebated kW capacity) is positive – which signifies discharging – for peak hours. Residential storage systems are charging, on average, during off-peak and partial-peak hours. While this seems intuitive for off-peak, charging during partial peak-hours may not. However, partial-peak hours occur during late morning and early afternoon[16] where we find evidence of storage systems charging from on-site PV generation.

FIGURE 4-35: HOURLY NET DISCHARGE KW PER REBATED KW FOR RESIDENTIAL PROJECTS BY RATE SEASON



15 We will discuss how customer rate structures may have had an impact on energy discharge during peak periods in the following section.

16 The E-6 rate, for example, has a summer partial peak period of 10 am to 1 pm.

We also examined the timing of aggregated storage dispatch to better understand how storage systems are being utilized throughout the year. We performed this analysis by taking the average hourly charge and discharge kW (normalized by rebated kW capacity) for each month and hour within the year for the sample of residential projects. This analysis was first conducted on all sampled projects, regardless if they were on a TOU rate or not. Figure 4-36 and Figure 4-37 present the findings. Discharging is positive and is shown in green and charging is negative and is shown in red. Again, all data are presented as period beginning in PST.

As noted previously, there were few projects receiving upfront payments in 2018 that had a full year of available data, so many of the observations from January through May are influenced by the legacy storage systems that were online throughout the entirety of 2018. During summer months and within the latter part of the year, storage discharge is more prominent in the afternoon and early evening hours and charging follows the shape of early PV generation hours.

FIGURE 4-36: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS

	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	0.015	0.033	0.023	0.025	0.031	0.027	0.018	0.024	0.024	0.022	0.016	0.009
1	0.008	0.020	0.019	0.026	0.023	0.020	0.014	0.018	0.018	0.016	0.011	0.006
2	0.003	0.013	0.016	0.020	0.019	0.017	0.012	0.014	0.015	0.014	0.009	0.005
3	0.003	0.010	0.013	0.018	0.017	0.016	0.010	0.012	0.013	0.013	0.007	0.004
4	0.002	0.008	0.013	0.018	0.017	0.017	0.010	0.012	0.013	0.012	0.007	0.004
5	0.002	0.007	0.014	0.020	0.017	0.015	0.009	0.011	0.013	0.013	0.007	0.004
6	0.003	0.007	0.012	0.012	0.010	0.008	0.007	0.009	0.011	0.011	0.007	0.004
7	0.002	0.006	0.005	0.005	0.005	0.004	0.006	0.006	0.006	0.005	0.004	0.003
8	0.001	0.003	0.003	0.002	0.003	0.003	0.005	0.004	0.004	0.004	0.003	0.002
9	0.001	0.003	0.003	0.002	0.002	0.003	0.004	0.004	0.003	0.003	0.003	0.002
10	0.002	0.003	0.003	0.003	0.003	0.003	0.005	0.006	0.005	0.004	0.003	0.003
11	0.104	0.094	0.080	0.077	0.065	0.045	0.041	0.030	0.025	0.023	0.020	0.020
12	0.104	0.097	0.081	0.075	0.066	0.045	0.042	0.031	0.026	0.024	0.021	0.021
13	0.022	0.014	0.014	0.012	0.017	0.022	0.026	0.029	0.024	0.021	0.011	0.008
14	0.025	0.012	0.010	0.009	0.016	0.053	0.070	0.064	0.067	0.074	0.072	0.067
15	0.030	0.014	0.015	0.015	0.021	0.054	0.067	0.072	0.075	0.072	0.061	0.060
16	0.048	0.030	0.025	0.040	0.045	0.135	0.160	0.172	0.172	0.096	0.088	0.081
17	0.053	0.065	0.050	0.057	0.063	0.104	0.121	0.141	0.139	0.109	0.092	0.089
18	0.045	0.076	0.070	0.081	0.086	0.074	0.079	0.111	0.109	0.097	0.078	0.072
19	0.035	0.061	0.065	0.090	0.090	0.066	0.066	0.094	0.089	0.076	0.060	0.052
20	0.027	0.052	0.056	0.074	0.073	0.056	0.052	0.074	0.067	0.056	0.046	0.038
21	0.018	0.041	0.044	0.056	0.056	0.048	0.042	0.051	0.047	0.044	0.034	0.026
22	0.011	0.034	0.038	0.050	0.053	0.036	0.030	0.035	0.036	0.035	0.025	0.018
23	0.009	0.038	0.034	0.035	0.040	0.032	0.025	0.030	0.032	0.029	0.019	0.012

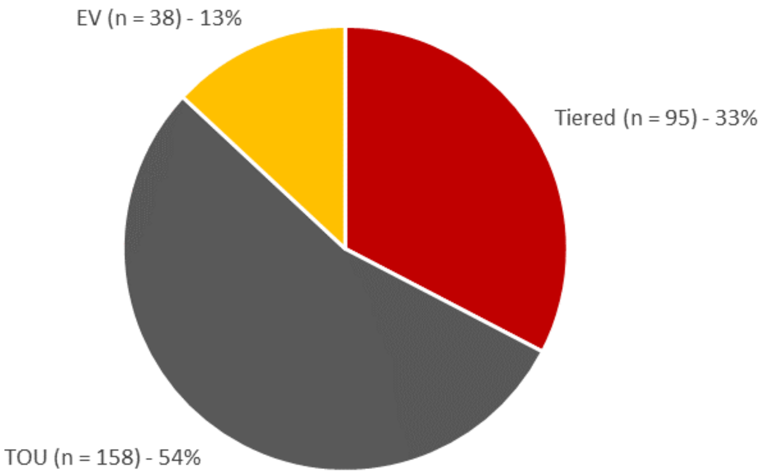
FIGURE 4-37: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS

	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	-0.004	-0.006	-0.006	-0.006	-0.005	-0.006	-0.005	-0.002	-0.003	-0.004	-0.006	-0.006
1	-0.004	-0.007	-0.004	-0.003	-0.005	-0.004	-0.007	-0.005	-0.005	-0.005	-0.007	-0.006
2	-0.004	-0.006	-0.004	-0.003	-0.005	-0.004	-0.007	-0.005	-0.004	-0.004	-0.006	-0.004
3	-0.004	-0.005	-0.004	-0.003	-0.005	-0.004	-0.006	-0.005	-0.004	-0.004	-0.005	-0.003
4	-0.004	-0.004	-0.003	-0.003	-0.004	-0.004	-0.006	-0.004	-0.003	-0.003	-0.005	-0.003
5	-0.004	-0.004	-0.003	-0.003	-0.004	-0.004	-0.004	-0.003	-0.002	-0.001	-0.004	-0.002
6	-0.004	-0.004	-0.005	-0.012	-0.018	-0.024	-0.017	-0.018	-0.012	-0.007	-0.005	-0.003
7	-0.006	-0.010	-0.028	-0.057	-0.062	-0.082	-0.059	-0.067	-0.056	-0.042	-0.027	-0.012
8	-0.022	-0.050	-0.075	-0.129	-0.125	-0.161	-0.129	-0.152	-0.141	-0.114	-0.082	-0.053
9	-0.058	-0.101	-0.118	-0.173	-0.163	-0.224	-0.202	-0.235	-0.232	-0.187	-0.143	-0.114
10	-0.088	-0.128	-0.128	-0.157	-0.155	-0.204	-0.211	-0.251	-0.258	-0.202	-0.163	-0.145
11	-0.076	-0.103	-0.107	-0.112	-0.118	-0.124	-0.143	-0.186	-0.199	-0.165	-0.139	-0.137
12	-0.060	-0.087	-0.083	-0.072	-0.082	-0.066	-0.078	-0.114	-0.125	-0.118	-0.104	-0.109
13	-0.089	-0.112	-0.092	-0.072	-0.081	-0.051	-0.063	-0.076	-0.078	-0.076	-0.073	-0.079
14	-0.128	-0.145	-0.115	-0.096	-0.096	-0.059	-0.065	-0.061	-0.056	-0.053	-0.044	-0.045
15	-0.109	-0.120	-0.102	-0.087	-0.085	-0.053	-0.054	-0.043	-0.035	-0.031	-0.025	-0.023
16	-0.031	-0.037	-0.031	-0.026	-0.027	-0.017	-0.018	-0.014	-0.010	-0.008	-0.007	-0.006
17	-0.016	-0.014	-0.012	-0.011	-0.010	-0.008	-0.008	-0.005	-0.002	-0.002	-0.002	-0.002
18	-0.022	-0.011	-0.007	-0.007	-0.007	-0.006	-0.006	-0.003	-0.003	-0.003	-0.002	-0.002
19	-0.034	-0.022	-0.013	-0.014	-0.011	-0.010	-0.009	-0.005	-0.005	-0.006	-0.004	-0.005
20	-0.023	-0.013	-0.009	-0.009	-0.007	-0.005	-0.005	-0.003	-0.003	-0.003	-0.003	-0.003
21	-0.019	-0.008	-0.007	-0.009	-0.007	-0.006	-0.005	-0.003	-0.002	-0.002	-0.002	-0.002
22	-0.015	-0.006	-0.007	-0.008	-0.007	-0.010	-0.008	-0.005	-0.005	-0.004	-0.002	-0.002
23	-0.006	-0.005	-0.006	-0.007	-0.005	-0.008	-0.007	-0.003	-0.005	-0.005	-0.005	-0.006

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 more than 10 unique customer rates from the sample of residential projects. All residential customers in the SGIP sample with a verified rate schedule were on some type of TOU or tiered volumetric rate. Figure 4-38 presents the different types of rates residential customers were on in 2018. Besides the E1 and domestic (DR) rate, all other rates have a TOU component. Again, differences stem from the time periods associated with peak, partial-peak and off-peak period definitions.

FIGURE 4-38: DISTRIBUTION OF RESIDENTIAL PROJECTS BY RATE TYPE



Finally, we compared the charge and discharge patterns for projects that were on a TOU rate to projects that were on a non-TOU rate. Figure 4-39 to Figure 4-42 present those results. Again, discharging is positive and is shown in green and charging is negative and is shown in red. All data are presented as period beginning in PST.

The projects on TOU rates show a clear signature of discharge during TOU periods, which range from:

- 2 pm to 7pm (PST) for customers on a TOU-A rate
- 3 pm to 8pm (PST) for customers on a TOU-B rate
- 1 pm to 8 pm (PST) for customers on an EV rate
- 12 pm to 6 pm (PST) for customers on an E-6 rate

The most significant discharge occurs in the summer period during the 4 pm to 5 pm (PST) hours. For residential projects on non-TOU rates, discharging occurs from 11 am to 12 pm in the winter months. However, this pattern is dominated by legacy storage systems. As projects received their upfront payments throughout the year, discharge patterns begin to resemble those of TOU customers. Charging patterns are similar across the two rate types.

FIGURE 4-39: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS ON TOU RATE

	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	0.034	0.064	0.034	0.034	0.039	0.027	0.018	0.021	0.022	0.018	0.011	0.006
1	0.016	0.037	0.025	0.036	0.027	0.018	0.014	0.015	0.014	0.013	0.008	0.004
2	0.003	0.019	0.021	0.024	0.020	0.015	0.011	0.011	0.011	0.010	0.005	0.003
3	0.002	0.014	0.015	0.020	0.018	0.014	0.010	0.010	0.010	0.008	0.004	0.002
4	0.002	0.011	0.014	0.019	0.017	0.014	0.010	0.009	0.009	0.008	0.004	0.003
5	0.001	0.009	0.016	0.019	0.015	0.011	0.009	0.010	0.010	0.009	0.004	0.002
6	0.001	0.010	0.014	0.010	0.007	0.005	0.006	0.008	0.009	0.009	0.004	0.002
7	0.001	0.006	0.005	0.004	0.004	0.004	0.006	0.006	0.005	0.005	0.003	0.003
8	0.000	0.004	0.004	0.001	0.002	0.004	0.006	0.005	0.004	0.004	0.003	0.002
9	0.002	0.004	0.004	0.002	0.002	0.003	0.005	0.004	0.004	0.003	0.002	0.002
10	0.002	0.003	0.004	0.004	0.002	0.004	0.005	0.007	0.006	0.004	0.002	0.002
11	0.052	0.040	0.033	0.032	0.026	0.018	0.016	0.015	0.014	0.013	0.010	0.009
12	0.052	0.042	0.033	0.030	0.028	0.018	0.017	0.017	0.015	0.015	0.011	0.010
13	0.026	0.014	0.012	0.011	0.020	0.022	0.029	0.036	0.029	0.024	0.010	0.006
14	0.036	0.018	0.017	0.015	0.027	0.075	0.096	0.085	0.086	0.097	0.098	0.089
15	0.053	0.028	0.025	0.026	0.036	0.079	0.090	0.086	0.087	0.082	0.066	0.062
16	0.084	0.053	0.040	0.068	0.071	0.190	0.207	0.216	0.208	0.082	0.079	0.070
17	0.090	0.110	0.074	0.088	0.090	0.134	0.141	0.149	0.137	0.092	0.080	0.072
18	0.068	0.120	0.105	0.119	0.118	0.084	0.080	0.098	0.091	0.085	0.067	0.059
19	0.049	0.094	0.092	0.135	0.123	0.074	0.068	0.084	0.075	0.067	0.052	0.043
20	0.038	0.078	0.080	0.110	0.097	0.059	0.050	0.069	0.057	0.046	0.037	0.028
21	0.025	0.062	0.063	0.081	0.073	0.049	0.041	0.045	0.039	0.036	0.026	0.018
22	0.015	0.053	0.059	0.077	0.075	0.037	0.031	0.030	0.030	0.030	0.018	0.012
23	0.013	0.070	0.053	0.052	0.056	0.031	0.027	0.024	0.028	0.024	0.014	0.008

FIGURE 4-40: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS ON NON-TOU RATE

	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	0.004	0.011	0.015	0.017	0.021	0.027	0.016	0.028	0.028	0.027	0.023	0.016
1	0.003	0.009	0.013	0.016	0.020	0.025	0.015	0.023	0.025	0.023	0.017	0.011
2	0.003	0.008	0.012	0.015	0.018	0.023	0.013	0.019	0.022	0.021	0.015	0.009
3	0.003	0.006	0.012	0.016	0.017	0.022	0.012	0.017	0.020	0.020	0.014	0.008
4	0.003	0.006	0.012	0.016	0.018	0.023	0.011	0.015	0.019	0.019	0.012	0.007
5	0.003	0.005	0.013	0.021	0.019	0.022	0.011	0.014	0.018	0.020	0.013	0.006
6	0.004	0.005	0.011	0.014	0.014	0.014	0.009	0.011	0.014	0.015	0.012	0.006
7	0.003	0.005	0.006	0.005	0.006	0.005	0.007	0.006	0.006	0.006	0.006	0.004
8	0.002	0.002	0.003	0.003	0.004	0.003	0.005	0.004	0.004	0.004	0.003	0.002
9	0.001	0.002	0.002	0.001	0.003	0.002	0.003	0.004	0.002	0.004	0.004	0.002
10	0.001	0.002	0.002	0.002	0.003	0.002	0.004	0.005	0.003	0.004	0.004	0.005
11	0.134	0.132	0.120	0.119	0.110	0.096	0.092	0.052	0.043	0.039	0.037	0.040
12	0.134	0.134	0.121	0.118	0.109	0.095	0.094	0.054	0.045	0.041	0.040	0.041
13	0.020	0.014	0.015	0.013	0.014	0.021	0.021	0.019	0.014	0.016	0.013	0.013
14	0.019	0.007	0.004	0.003	0.003	0.012	0.015	0.028	0.034	0.036	0.026	0.025
15	0.017	0.005	0.006	0.005	0.004	0.007	0.019	0.049	0.056	0.054	0.052	0.055
16	0.028	0.014	0.012	0.013	0.016	0.027	0.058	0.099	0.110	0.119	0.104	0.102
17	0.031	0.033	0.030	0.027	0.032	0.045	0.077	0.126	0.141	0.138	0.113	0.121
18	0.032	0.045	0.041	0.044	0.049	0.055	0.078	0.132	0.140	0.116	0.098	0.099
19	0.026	0.038	0.042	0.046	0.053	0.052	0.061	0.111	0.112	0.091	0.074	0.070
20	0.020	0.034	0.036	0.039	0.044	0.049	0.055	0.083	0.084	0.073	0.062	0.057
21	0.015	0.027	0.028	0.031	0.035	0.045	0.044	0.061	0.060	0.056	0.048	0.041
22	0.009	0.020	0.021	0.023	0.028	0.034	0.027	0.045	0.045	0.042	0.037	0.029
23	0.007	0.015	0.017	0.018	0.022	0.034	0.019	0.040	0.039	0.039	0.028	0.018

FIGURE 4-41: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS ON TOU RATE

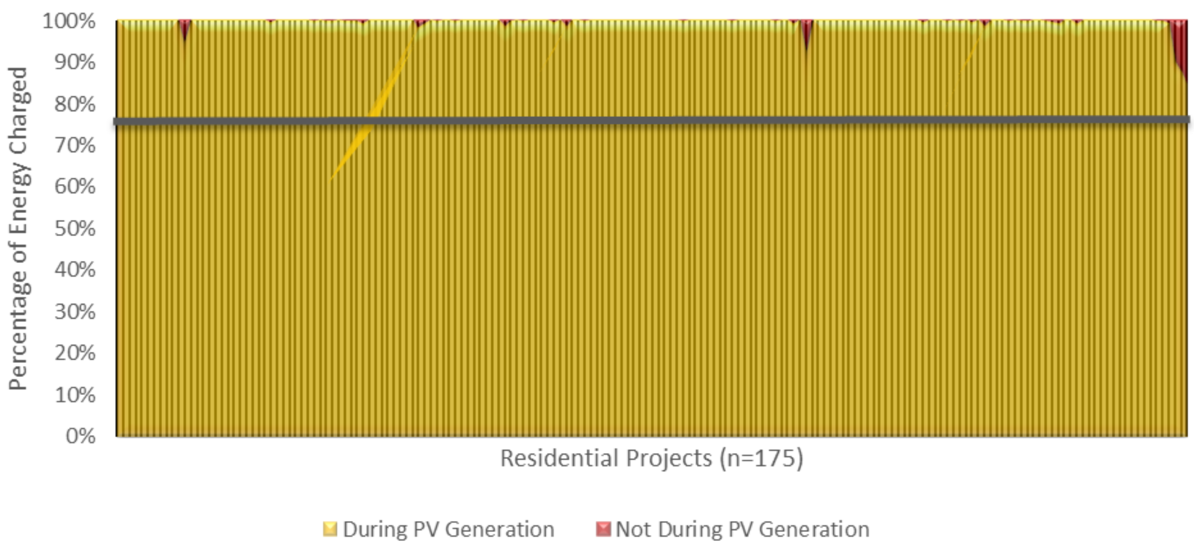
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.002	-0.007	-0.007	-0.006	-0.005	-0.005	-0.005	-0.003	-0.004	-0.006	-0.006	-0.006
1	-0.003	-0.010	-0.003	-0.001	-0.001	-0.002	-0.003	-0.002	-0.003	-0.004	-0.006	-0.005
2	-0.003	-0.008	-0.003	-0.002	-0.001	-0.001	-0.003	-0.002	-0.002	-0.002	-0.005	-0.003
3	-0.003	-0.004	-0.002	-0.002	-0.001	-0.001	-0.002	-0.002	-0.002	-0.002	-0.003	-0.002
4	-0.002	-0.002	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
5	-0.002	-0.002	-0.002	-0.002	-0.003	-0.003	-0.002	-0.001	-0.001	-0.001	-0.001	-0.002
6	-0.002	-0.002	-0.004	-0.016	-0.026	-0.029	-0.018	-0.014	-0.009	-0.004	-0.002	-0.001
7	-0.005	-0.014	-0.041	-0.089	-0.096	-0.107	-0.075	-0.069	-0.054	-0.038	-0.024	-0.010
8	-0.040	-0.095	-0.115	-0.200	-0.187	-0.203	-0.158	-0.161	-0.144	-0.108	-0.079	-0.049
9	-0.109	-0.184	-0.178	-0.253	-0.232	-0.275	-0.243	-0.253	-0.243	-0.177	-0.138	-0.111
10	-0.154	-0.214	-0.184	-0.224	-0.206	-0.237	-0.246	-0.269	-0.272	-0.184	-0.151	-0.136
11	-0.124	-0.168	-0.147	-0.148	-0.144	-0.133	-0.159	-0.190	-0.198	-0.146	-0.126	-0.122
12	-0.084	-0.126	-0.110	-0.088	-0.094	-0.063	-0.082	-0.110	-0.117	-0.105	-0.092	-0.093
13	-0.079	-0.115	-0.090	-0.064	-0.065	-0.039	-0.054	-0.068	-0.066	-0.064	-0.060	-0.063
14	-0.074	-0.101	-0.076	-0.053	-0.055	-0.031	-0.039	-0.045	-0.039	-0.038	-0.030	-0.028
15	-0.046	-0.063	-0.051	-0.039	-0.041	-0.024	-0.027	-0.026	-0.020	-0.019	-0.012	-0.011
16	-0.014	-0.016	-0.012	-0.009	-0.014	-0.009	-0.009	-0.009	-0.005	-0.004	-0.003	-0.002
17	-0.016	-0.011	-0.006	-0.004	-0.005	-0.004	-0.004	-0.003	-0.001	-0.002	-0.001	-0.001
18	-0.021	-0.012	-0.008	-0.008	-0.007	-0.007	-0.006	-0.004	-0.004	-0.003	-0.002	-0.002
19	-0.035	-0.024	-0.015	-0.013	-0.010	-0.007	-0.006	-0.004	-0.003	-0.004	-0.004	-0.004
20	-0.028	-0.021	-0.013	-0.011	-0.009	-0.006	-0.005	-0.003	-0.003	-0.003	-0.003	-0.002
21	-0.017	-0.010	-0.009	-0.010	-0.008	-0.005	-0.005	-0.003	-0.003	-0.003	-0.002	-0.002
22	-0.011	-0.006	-0.009	-0.010	-0.008	-0.011	-0.009	-0.006	-0.006	-0.005	-0.002	-0.002
23	-0.005	-0.004	-0.008	-0.008	-0.006	-0.008	-0.007	-0.004	-0.006	-0.008	-0.004	-0.005

FIGURE 4-42: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS ON NON-TOU RATE

	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	-0.005	-0.005	-0.005	-0.006	-0.004	-0.008	-0.005	-0.002	-0.002	-0.002	-0.005	-0.005
1	-0.005	-0.005	-0.005	-0.005	-0.009	-0.010	-0.016	-0.010	-0.008	-0.008	-0.010	-0.008
2	-0.005	-0.005	-0.006	-0.005	-0.009	-0.010	-0.016	-0.010	-0.008	-0.008	-0.008	-0.007
3	-0.005	-0.005	-0.005	-0.005	-0.009	-0.010	-0.016	-0.010	-0.009	-0.008	-0.008	-0.007
4	-0.005	-0.005	-0.005	-0.004	-0.007	-0.010	-0.016	-0.010	-0.008	-0.008	-0.011	-0.007
5	-0.005	-0.005	-0.004	-0.004	-0.004	-0.005	-0.008	-0.005	-0.004	-0.003	-0.008	-0.004
6	-0.005	-0.005	-0.005	-0.008	-0.009	-0.012	-0.017	-0.023	-0.018	-0.011	-0.010	-0.005
7	-0.006	-0.007	-0.016	-0.026	-0.024	-0.032	-0.025	-0.063	-0.059	-0.048	-0.032	-0.017
8	-0.012	-0.019	-0.042	-0.061	-0.055	-0.078	-0.065	-0.136	-0.136	-0.123	-0.088	-0.059
9	-0.029	-0.045	-0.068	-0.096	-0.086	-0.123	-0.112	-0.205	-0.213	-0.203	-0.152	-0.119
10	-0.051	-0.069	-0.081	-0.094	-0.096	-0.138	-0.132	-0.220	-0.233	-0.233	-0.184	-0.161
11	-0.049	-0.059	-0.073	-0.077	-0.088	-0.105	-0.106	-0.178	-0.201	-0.196	-0.164	-0.166
12	-0.046	-0.061	-0.061	-0.057	-0.068	-0.072	-0.069	-0.121	-0.138	-0.139	-0.127	-0.141
13	-0.094	-0.110	-0.094	-0.080	-0.098	-0.075	-0.084	-0.088	-0.100	-0.097	-0.097	-0.110
14	-0.159	-0.175	-0.147	-0.137	-0.143	-0.115	-0.123	-0.088	-0.084	-0.079	-0.071	-0.078
15	-0.144	-0.160	-0.145	-0.132	-0.135	-0.110	-0.113	-0.072	-0.061	-0.052	-0.047	-0.045
16	-0.040	-0.052	-0.047	-0.042	-0.041	-0.034	-0.037	-0.023	-0.018	-0.013	-0.014	-0.012
17	-0.016	-0.015	-0.017	-0.016	-0.016	-0.015	-0.016	-0.007	-0.004	-0.003	-0.004	-0.004
18	-0.023	-0.010	-0.007	-0.007	-0.007	-0.006	-0.005	-0.002	-0.003	-0.003	-0.002	-0.002
19	-0.034	-0.021	-0.012	-0.015	-0.012	-0.015	-0.015	-0.007	-0.007	-0.010	-0.006	-0.006
20	-0.020	-0.008	-0.006	-0.007	-0.006	-0.004	-0.004	-0.003	-0.002	-0.003	-0.003	-0.004
21	-0.020	-0.006	-0.005	-0.007	-0.005	-0.009	-0.006	-0.002	-0.002	-0.002	-0.002	-0.002
22	-0.018	-0.006	-0.005	-0.006	-0.005	-0.009	-0.006	-0.002	-0.004	-0.002	-0.002	-0.002
23	-0.007	-0.005	-0.005	-0.006	-0.004	-0.009	-0.005	-0.002	-0.002	-0.002	-0.007	-0.006

The pattern of charging, which closely aligns with early PV generation hours provides clear evidence that projects are performing PV self-consumption. In order to quantify the magnitude, we conducted an analysis of how much energy each project was charging from PV. Given the fact that the majority of residential storage systems that have applied since 2017 have indicated they are paired with and charging from solar PV, this analysis seems reasonable. This analysis was only conducted for projects where the evaluation team had actual PV generation data. Figure 4-43 presents those results. All of the sampled projects achieved the 75 percent or greater threshold, with most projects charging exclusively from PV.

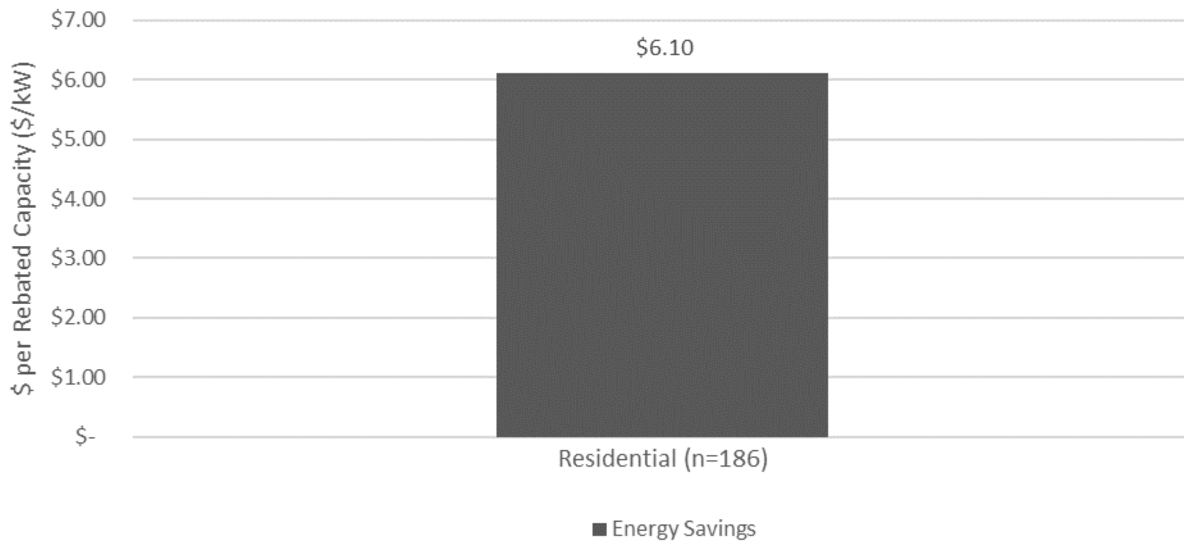
FIGURE 4-43: 2018 SGIP RESIDENTIAL PROJECT CHARGE FROM PV



Overall Customer Bill Savings ($/kW) for Residential Projects on a TOU Rate

We combined the energy rates charged during each of the TOU periods and compared energy consumption with storage versus calculated energy consumption in the absence of storage to develop bill impact estimates for residential customers. The expectation is that customers on a TOU energy rate are discharging during peak periods when energy rates are high and charging during periods of lower prices (early morning hours when PV generation is ramping), which would translate into bill savings. The vertical axis represents the average overall bill savings in dollars for residential customers on a TOU rate in 2018, normalized by rebated capacity. Customers on tiered volumetric rates with no TOU price differentials cannot achieve bill savings with energy storage since round-trip efficiency losses will result in increased overall energy consumption.

FIGURE 4-44: RESIDENTIAL OVERALL CUSTOMER BILL SAVINGS ($/KW) ON TOU RATES



4.4 CAISO AND IOU SYSTEM IMPACTS

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 projects are generally being utilized to reduce non-coincident monthly peak demand and, to a lesser extent, TOU energy arbitrage. Benefits that may accrue to the CAISO or IOU systems are potentially due to participation in demand response programs (both system-level/localized and real-time/day-ahead), enrollment in IOU tariffs which include peak energy pricing like Critical Peak Pricing (CPP) or Peak Day Pricing (PDP) or are just merely 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 our sample of nonresidential and residential projects throughout the top 200 peak demand hours in 2018 for both the CAISO system[17] as well as the three IOUs.

[17] The top 200 CAISO peak hours all fall within July and August, beginning on 7/6 and ending on 8/20. The top CAISO load hour was on 7/25 at 4 pm (PST).

4.4.1 Nonresidential System Impacts

Figure 4-45 below presents the average kW discharge per rebated capacity for non-PBI projects along with the peak MW for each of the top 200 CAISO hours. Non-PBI projects were charging during 165 of the top 200 hours and therefore increasing coincident peak demand during those hours. These results are consistent with findings from the 2017 SGIP Advanced Energy Storage Impact Evaluation, both in terms of the magnitude of average net discharge kW throughout the top 200 hours in 2017 and the number of hours where SGIP AES projects were increasing coincident peak demand (180 of 200 hours in 2017[18]).

FIGURE 4-45: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS FOR NON-PBI PROJECTS

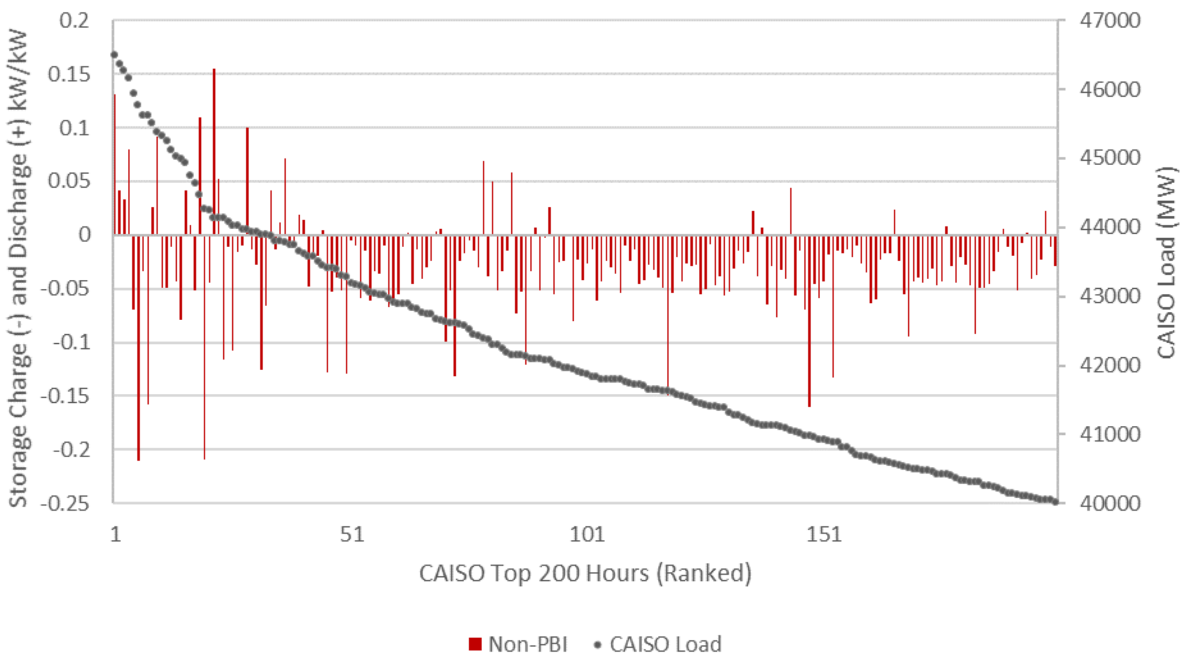
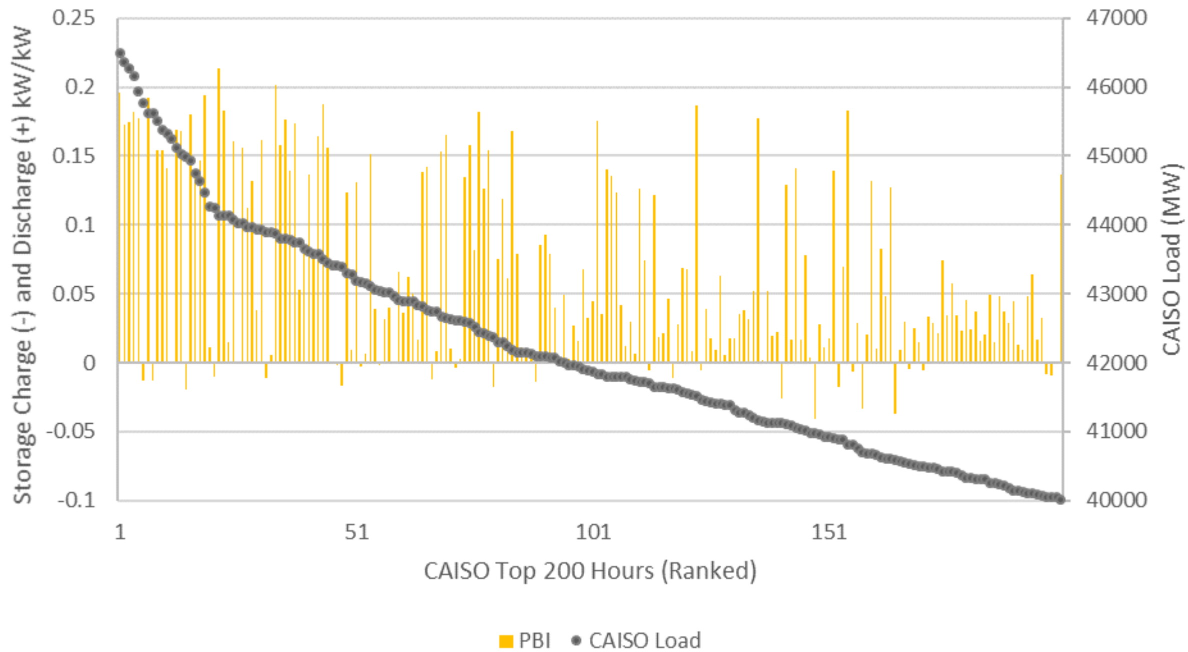


Figure 4-46 presents the average kW discharge per rebated capacity for PBI projects along with the peak MW for each of the top 200 CAISO hours. PBI projects were discharging throughout 170 of the top 200 CAISO peak hours and therefore contributing to coincident peak demand reduction. These results, however, are less consistent with findings from the 2017 SGIP Advanced Energy Storage Impact

[18] It's important to note, CAISO peak hours in 2017 are different from peak hours in 2018. For example, the top CAISO load hour in 2017 was on 9/1 at 3 pm (PST), whereas the top load hour in 2018 was on 7/25 at 4 pm (PST).

Evaluation, in terms of the magnitude of average net discharge kW throughout the top 200 hours in 2017.

FIGURE 4-46: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS FOR PBI PROJECTS

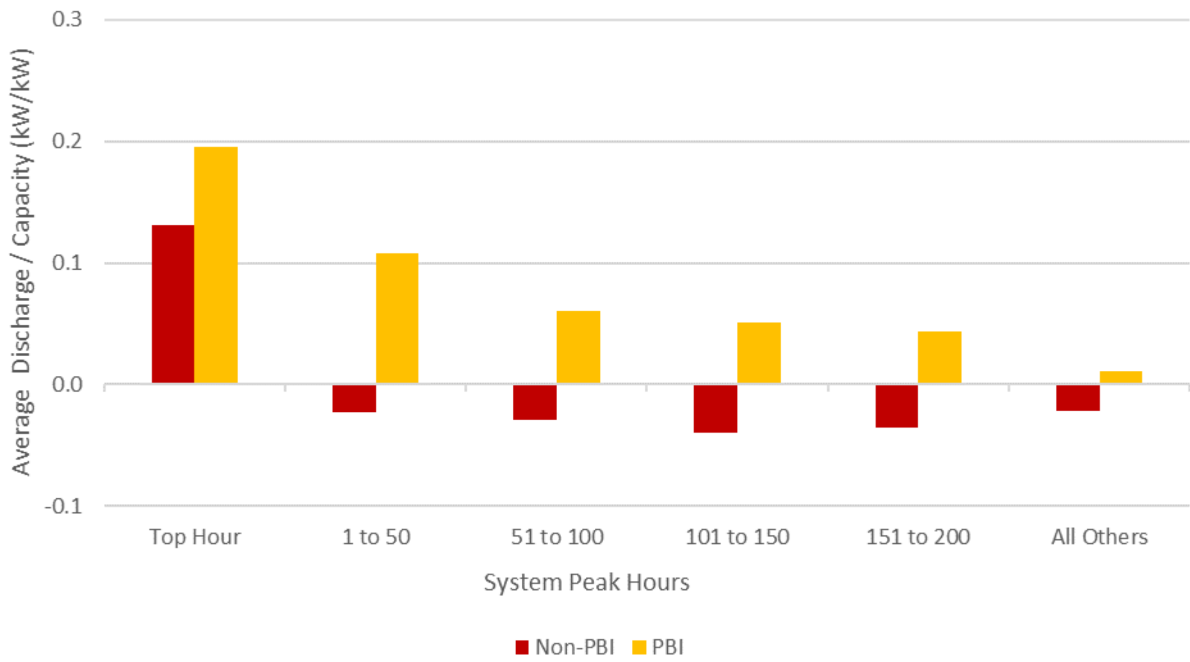


We also examined how the average net discharge throughout the top 200 system peak hours (2018) compared to the average across the remaining hours within the summer. All 200 system peak hours occurred within July and August (inclusive) and within utility peak and partial-peak TOU periods, so we have defined summer within that context.[19]

Figure 4-47 presents the average net kW discharge (per rebated capacity) for non-PBI and PBI projects for different bins of top hours along with the summer average. On average, PBI projects are discharging roughly 0.20 kW per kW rebated capacity during the CAISO peak hour. Non-PBI projects are also discharging roughly 0.13 kW per kW rebated capacity during that hour. A similar trend is evident across the other bins for PBI projects. PBI storage systems are discharging, on average, throughout all other summer hours defined as peak or partial-peak by TOU periods. Non-PBI projects are, on average, charging throughout those hours.

[19] This definition of summer is exclusive to this analysis. Customer bill impacts are based on the seasonal definitions within each customer's tariff.

FIGURE 4-47: NET DISCHARGE KW PER REBATED CAPACITY KW DURING CAISO PEAK HOURS FOR ALL PROJECTS WITH SUMMER AVERAGE



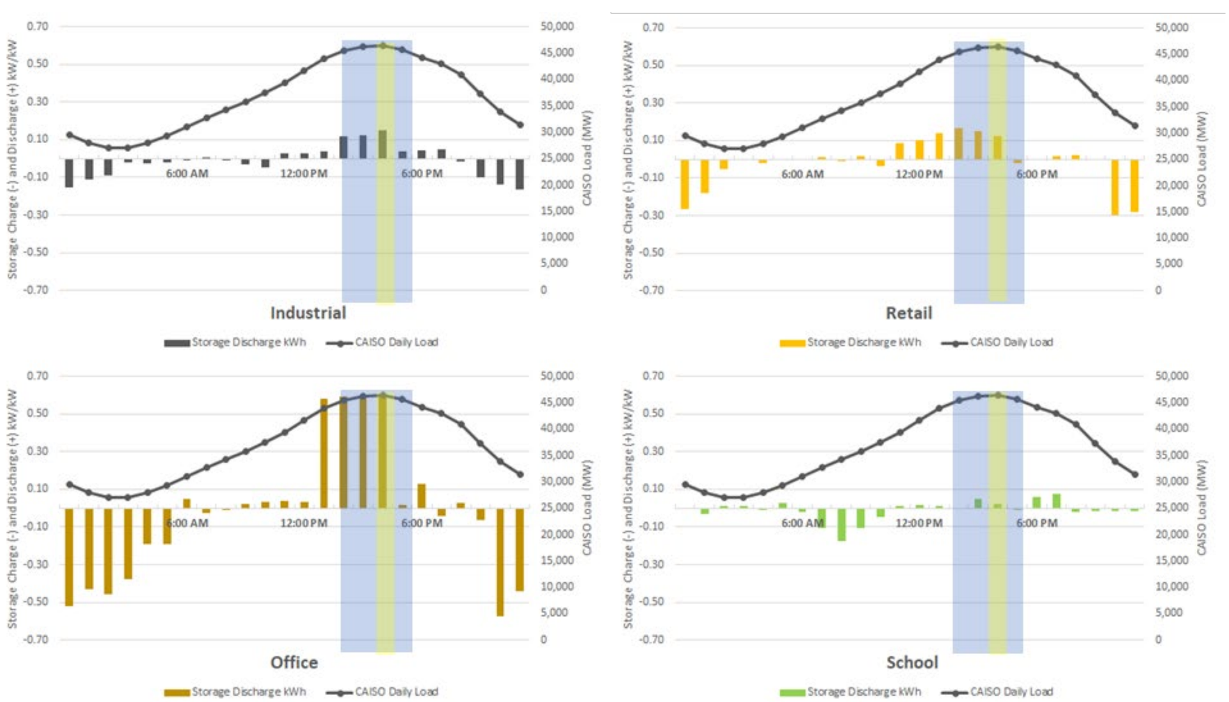
The overall pattern of charge and discharge during top CAISO hours – and throughout the summer, in general – follows a similar pattern to what has been found in previous evaluations. However, the magnitude of impacts during top hours continues to change from one evaluation to the next. This is due, in 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 program year to the next.

As presented above in Figure 4-47, PBI projects provided a net benefit to the CAISO system by discharging during the top hour in 2018. In 2017, while providing a net benefit, the magnitude of discharge for PBI projects was far less than in 2018 (0.04 kW per kW compared to roughly 0.2 kW per kW in 2018). In 2017, the five top CAISO hours occurred on September 1, 2017 from 1 pm through 5 pm (PST). Likewise, thirty-four additional primary and secondary schools received upfront payments in 2017 and were not subject to evaluation in the previous year. In 2017, schools were the only PBI facility type, on average, charging throughout top CAISO hours. These systems were presumably discharging throughout the morning ramp period to satisfy non-coincident facility demand and charged throughout the afternoon period to maintain a balanced state of charge.

In 2018, top CAISO hours occurred mostly in the summer– late July and early August – and the composition of the PBI population has changed once again. Twenty-two office projects received their upfront payments in 2018, increasing the total rebated capacity for that sector to 14 MW (Figure 3-5 in Section 3).

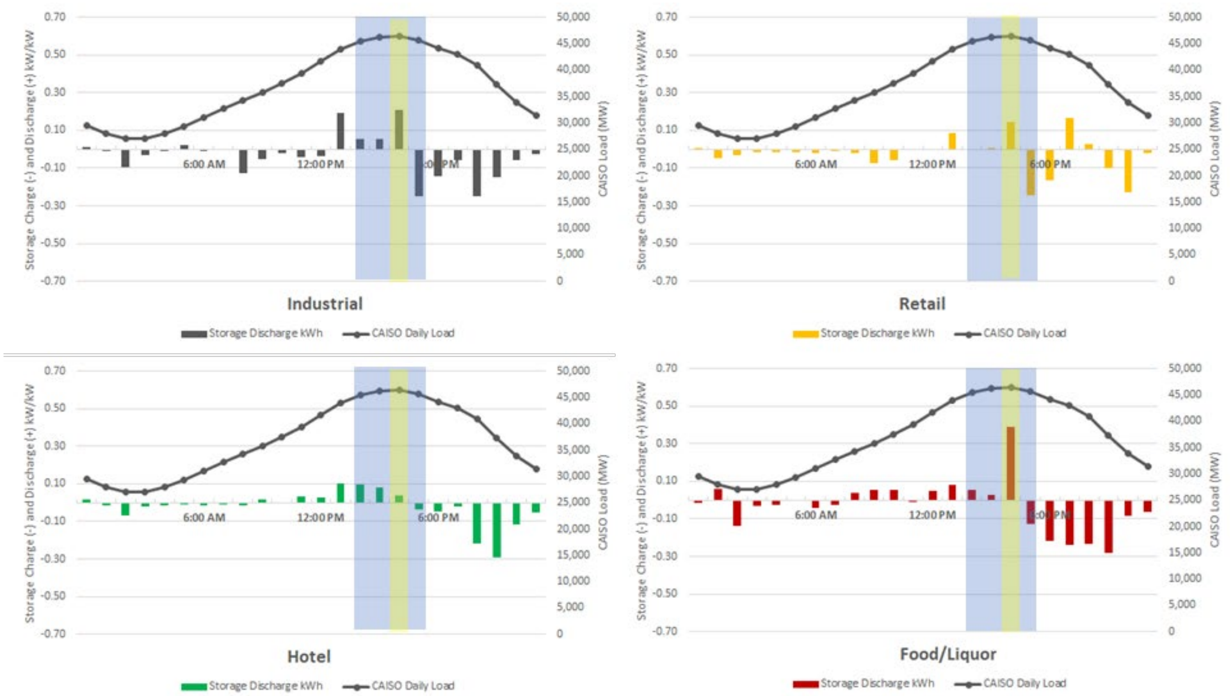
The magnitude and pattern of net discharge for different building types is presented below in Figure 4-48 for July 25th, 2018. The CAISO peaked during the 4pm PST hour on that day (highlighted in yellow in the figure) and three other top hours are highlighted in blue. Office projects, on average, were discharging significant energy during those hours (roughly 0.65 kW per kW) and schools were discharging, albeit at a lower magnitude, compared to charging during peak hours in 2017. Overall, these larger systems were net discharging throughout all the peak hours during that day and charging later in the evening. This behavior translates over to the positive net discharge across all hours in Figure 4-47.

FIGURE 4-48: STORAGE DISCHARGE KW ON JULY 25TH, 2018 BY BUILDING TYPE (PBI)



Conversely, non-PBI projects were discharging during the peak hour, but were charging, on average, throughout all others. As discussed previously and as evident below in Figure 4-49 and Figure 4-45, systems were discharging during the peak hour, but were often charging during successive top hours. Again, this could be explained by the fact that non-PBI customers are optimizing storage dispatch for non-coincident peak demand reduction. They are smaller systems that exhibit a “snap-back” effect where discharge events are immediately followed by a charge event. Larger storage systems exhibit discharge behavior, often followed by an idle period. Charging does not occur until later in the evening or overnight.

FIGURE 4-49: STORAGE DISCHARGE KW ON JULY 25TH, 2018 BY BUILDING TYPE (NON-PBI)



We also examined the net discharge behavior of storage systems during the peak load hours for the three IOUs. The results for PBI and non-PBI projects are presented in Figure 4-50 and Figure 4-51, respectively. The results are much like those for the CAISO peak hours. PBI projects, on average, are discharging during system peak hours and non-PBI projects, on average, are charging during those hours. One striking difference across utility top peak loads throughout 2018 is the average net discharge of storage systems operating in SCE territory. As presented above in Figure 4-48, offices were generally discharging throughout CAISO peak hours (many of which were coincident with SCE system load). Twenty of the twenty-two new PBI office storage systems were operating within SCE service territory in 2018.

FIGURE 4-50: NET DISCHARGE KW PER REBATED CAPACITY KW DURING SYSTEM PEAK HOURS FOR PBI PROJECTS

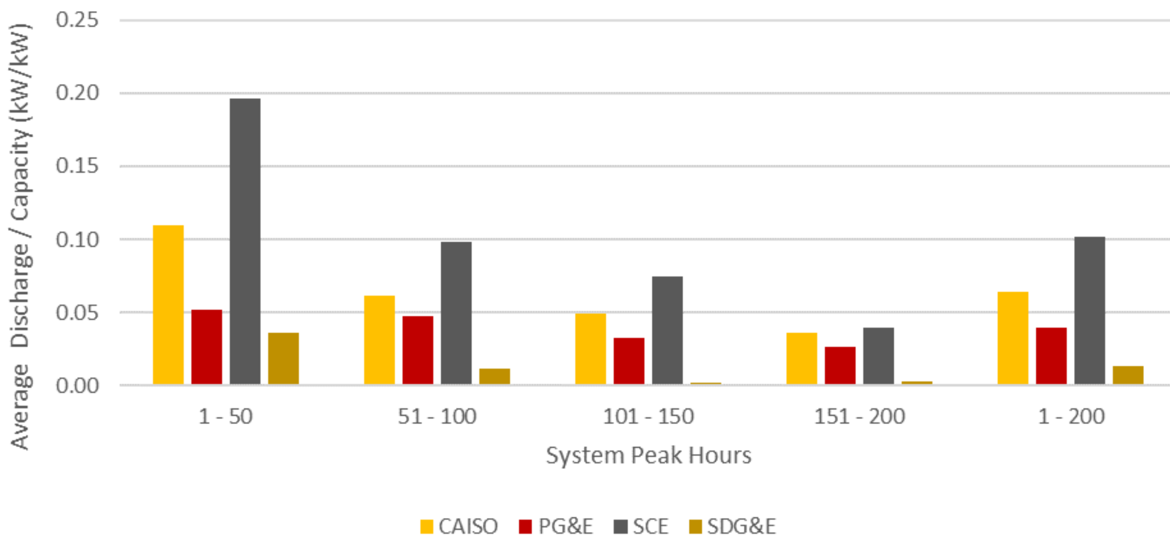
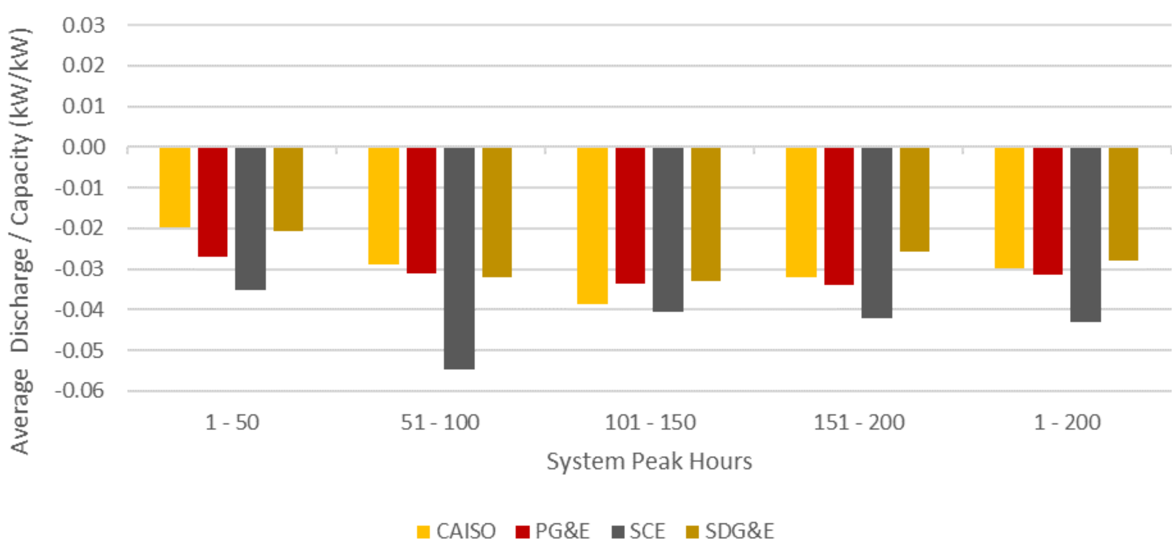


FIGURE 4-51: NET DISCHARGE KW PER REBATED CAPACITY KW DURING SYSTEM PEAK HOURS FOR NON-PBI PROJECTS



4.4.2 Residential System Impacts

Figure 4-52 presents the average kW discharge per rebated capacity for residential projects along with the peak MW for each of the top 200 CAISO hours. The pattern of charge and discharge of residential storage systems is comparable to PBI projects. During summer months (which coincide with the CAISO peak hours), most residential projects were charging from PV in the morning hours and discharging later in the afternoon and evening. This is evident below in Figure 4-52. Residential projects, on average, were discharging throughout 169 of the Top 200 hours. Of the 31 hours where projects were net charging on average, 28 of them were during the 12 and 1 pm (PST) hour. These are peak PV generation hours where many residential customers were still charging their storage systems from on-site PV.

FIGURE 4-52: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS FOR RESIDENTIAL PROJECTS

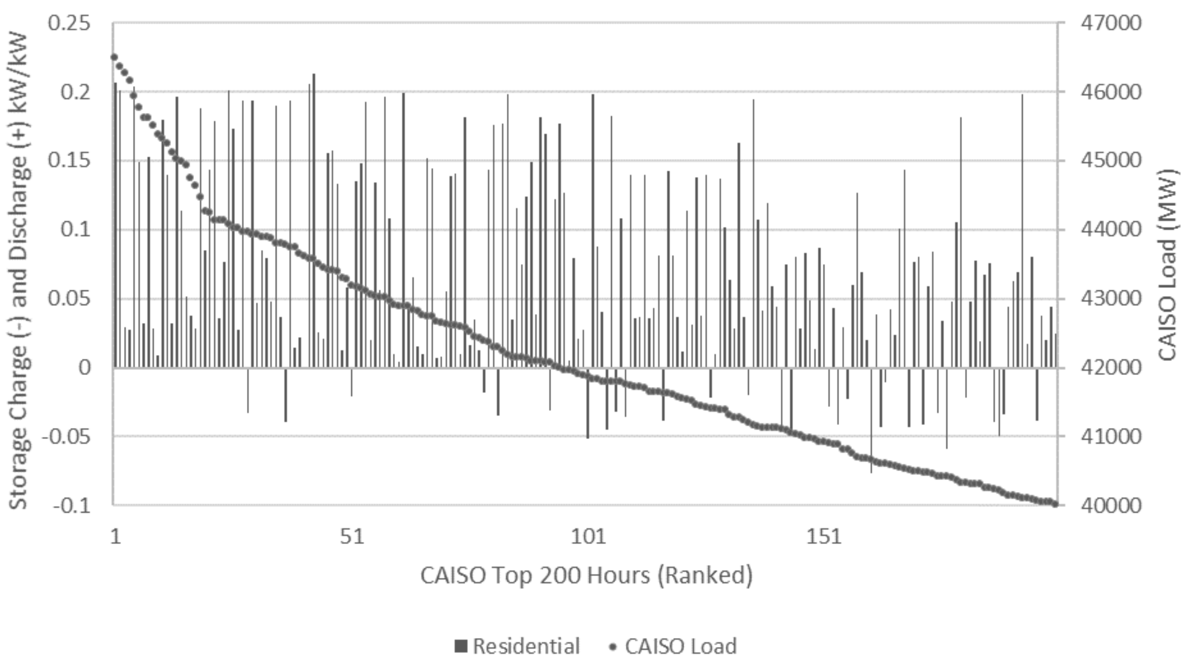


Figure 4-53 illustrates the net discharge behavior for residential projects on July 25th, 2018. As discussed above, on average, residential storage systems are charging throughout the morning when PV generation is ramping. These systems then begin discharging around 2pm PST[20] with the greatest magnitude of discharging occurring throughout the 4pm PST hour – which is coincident with the CAISO peak. Discharging continues throughout the early evening as PV generation wanes. Again, the length of discharge and the magnitude is predicated on the specific customer rate schedule.

FIGURE 4-53: STORAGE DISCHARGE KW ON JULY 25TH, 2018 FOR RESIDENTIAL PROJECTS

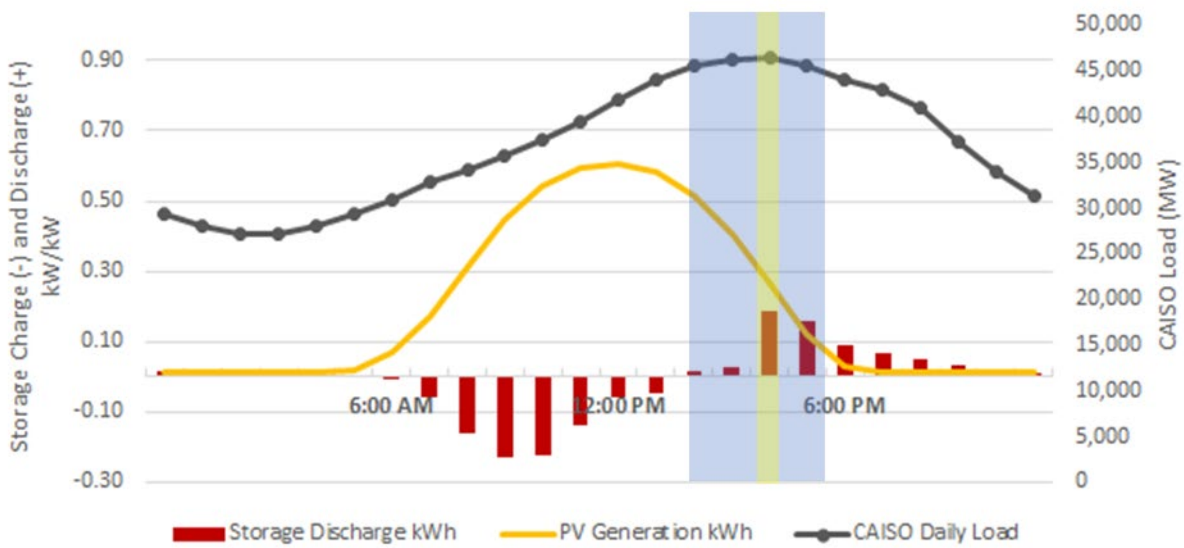


Figure 4-54 presents the average net kW discharge (per rebated capacity) for residential projects for different bins of top hours along with all other hours in July and August – during which, all Top 200 hours occurred. On average, residential projects are discharging roughly 0.20 kW per kW rebated capacity during the CAISO peak hour. A similar trend is evident across the other bins as well as at the IOU system level (Figure 4-55).

[20] This is an average over the course of one day. Customers will likely begin discharging based on the TOU period associated with their tariff.

FIGURE 4-54: NET DISCHARGE KW PER REBATED CAPACITY KW DURING CAISO PEAK HOURS FOR RESIDENTIAL PROJECTS

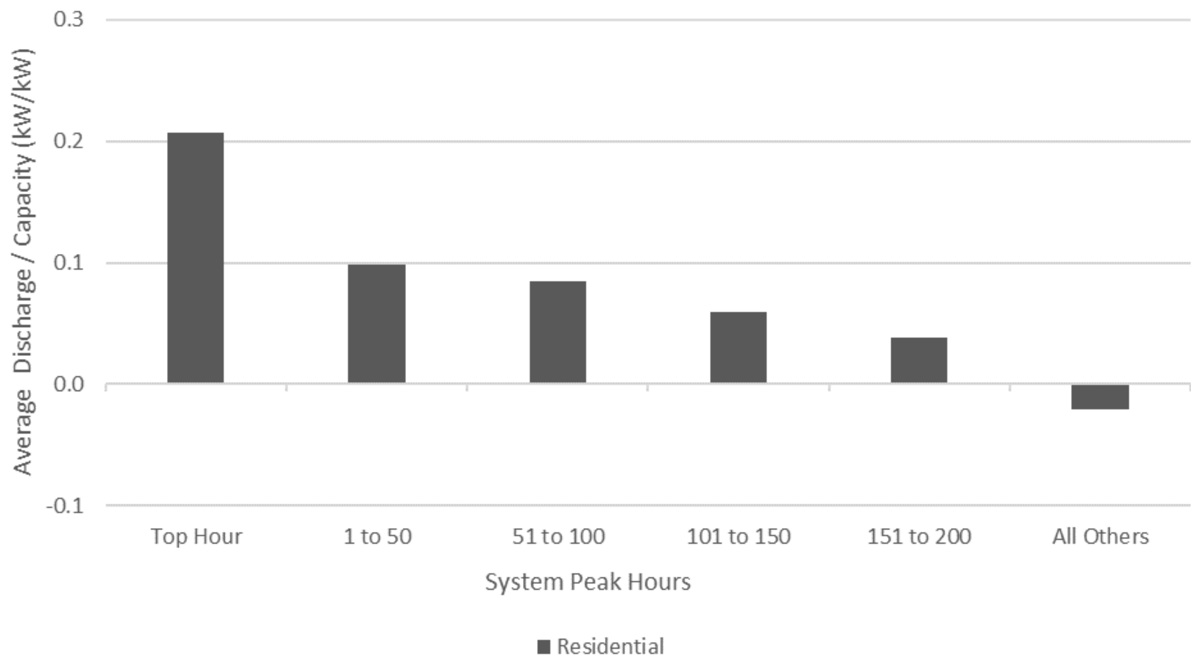
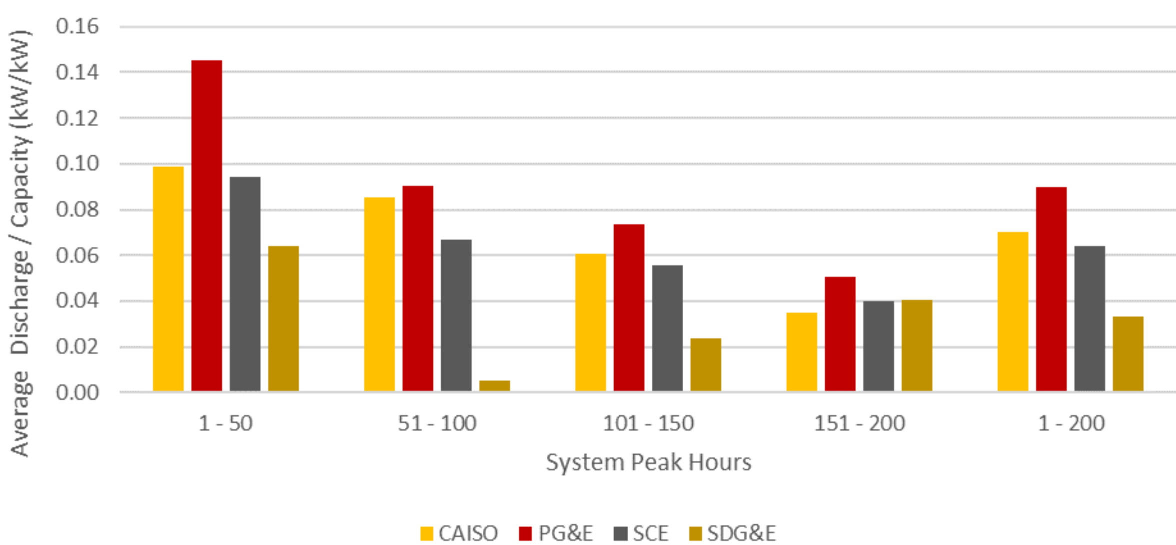


FIGURE 4-55: NET DISCHARGE KW PER REBATED CAPACITY KW DURING SYSTEM PEAK HOURS FOR RESIDENTIAL PROJECTS



4.5 ENVIRONMENTAL IMPACTS

This section summarizes the impact estimates of GHG and criteria air pollutants for SGIP rebated AES projects. 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 AES projects. The criteria air pollutants in this analysis are PM_{10} and NOx, both of which are pollutants generated from grid-scale gas power plants.

Fifteen-minute GHG, PM_{10} and NOx impacts were calculated for each SGIP project as the difference between the grid power plant emissions for actual SGIP AES operations and the emissions for the assumed baseline conditions. Baseline emissions are those that would have occurred in the absence of the SGIP AES project. 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 AES charging and discharging.

AES 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, AES technologies will increase the energy consumption of a customer's home or facility relative to the baseline condition without the AES.

The 15-minute energy (MWh) impact of each standalone SGIP AES project 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 (Metric Tons CO_2 / MWh for CO_2 or lbs./MWh for particulate matter and NOx) to arrive at a 15-minute emission impact. Emissions generally increase during AES charge and decrease during AES discharge. The project's annual GHG or criteria air pollutant impact is the sum of the 15-minute emissions.

For AES projects to reduce emissions, the emissions "avoided" during storage discharge must be greater than the emission increases during storage charging. Since AES technologies inherently consume more energy during charging relative to energy discharged, the marginal emissions rate must be lower during charging hours relative to discharge hours. In other words, SGIP storage projects must charge during "cleaner" grid hours and discharge during "dirtier" grid hours to achieve GHG reductions. Additional details on the GHG impact methodology and the assumptions made in developing a marginal GHG emissions dataset are included in Appendix A.

It is important to note that AES systems 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. Going forward, SGIP PAs will make available a day-ahead marginal emissions signal that will provide storage systems with information on forecasted hourly emissions rates.

4.5.1 Nonresidential Environmental Impacts

Figure 4-56 and Figure 4-57 convey the results of the GHG emission impact analysis for non-PBI and PBI projects, respectively. Storage dispatch behavior led to an increase in GHG emissions for 92 of 100 non-PBI projects and 180 of 211 PBI projects.

FIGURE 4-56: NET CO2 EMISSIONS PER REBATED CAPACITY FOR NON-PBI PROJECTS

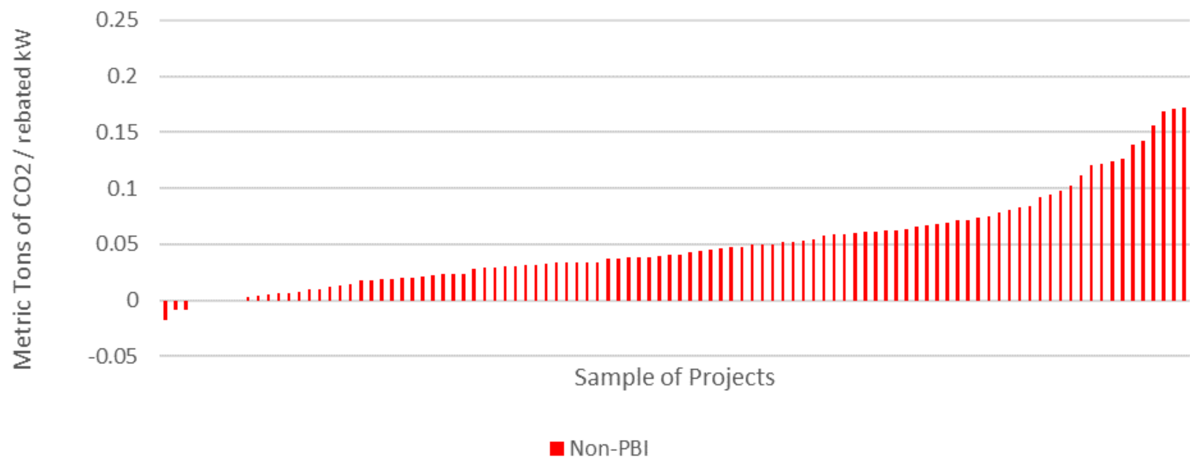


FIGURE 4-57: NET CO2 EMISSIONS PER REBATED CAPACITY FOR PBI PROJECTS

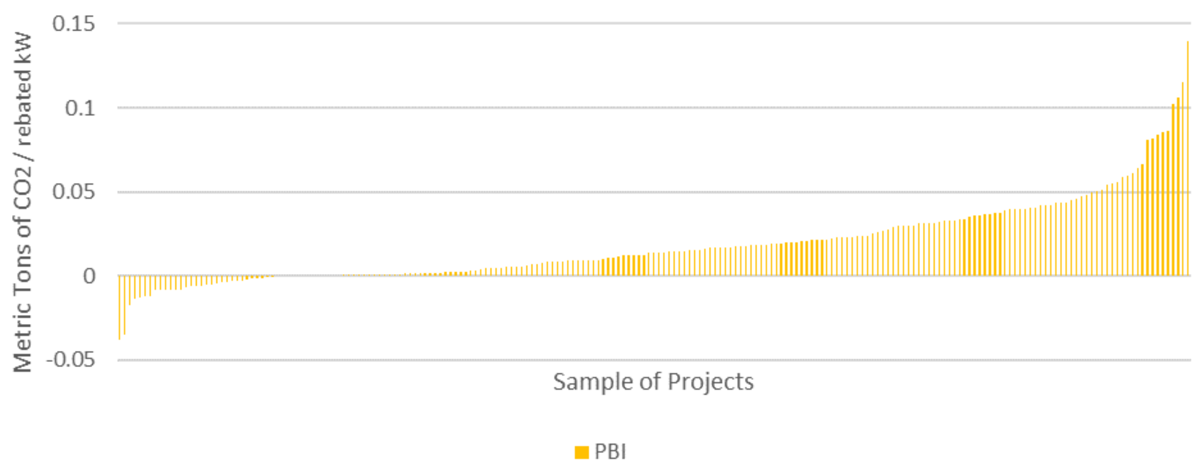
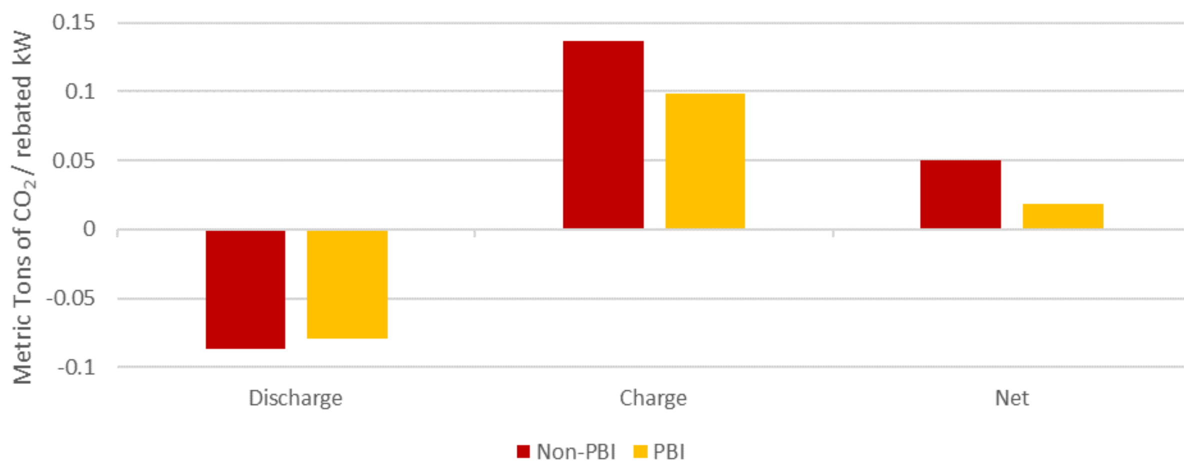


Figure 4-58 shows that, on average, both PBI and non-PBI projects are increasing emissions due to a combination of losses due to inefficiencies and less than ideal operation timing from a GHG perspective. The magnitude of normalized emissions for non-PBI projects is more significant overall.

FIGURE 4-58: AVERAGE CO2 EMISSIONS PER REBATED CAPACITY FOR NONRESIDENTIAL PROJECTS



The evaluation team estimated the impact that inefficiencies associated with parasitic losses have on the net GHG emissions for nonresidential projects. Figure 4-59 and Figure 4-60 present the influence these losses have on the overall GHG impacts for non-PBI nonresidential and PBI projects, respectively. Parasitic losses account for roughly 10 percent of the net GHG increase for non-PBI projects. While the magnitude of GHG increases for PBI projects is much greater than for non-PBI projects (a 1,135 metric ton increase compared to a 120 metric ton increase), the influence of parasitic losses is far less consequential (roughly 1.3 percent of total GHG increases).

FIGURE 4-59: WATERFALL OF TOTAL CO2 IMPACTS FOR NON-PBI PROJECTS (INCLUDING PARASITIC INFLUENCE)

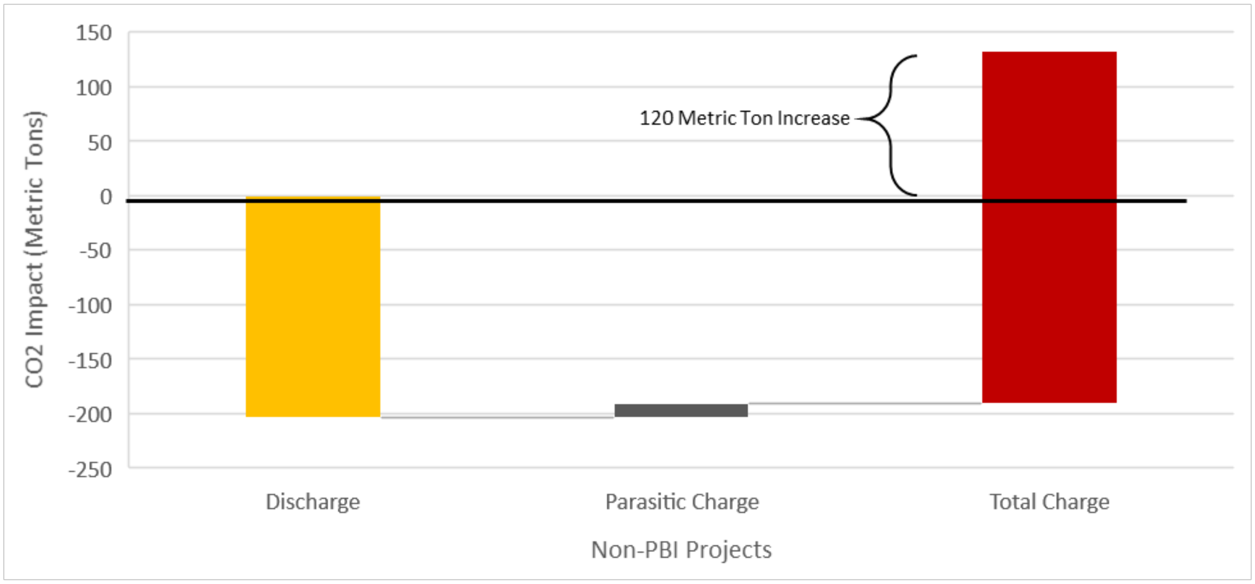
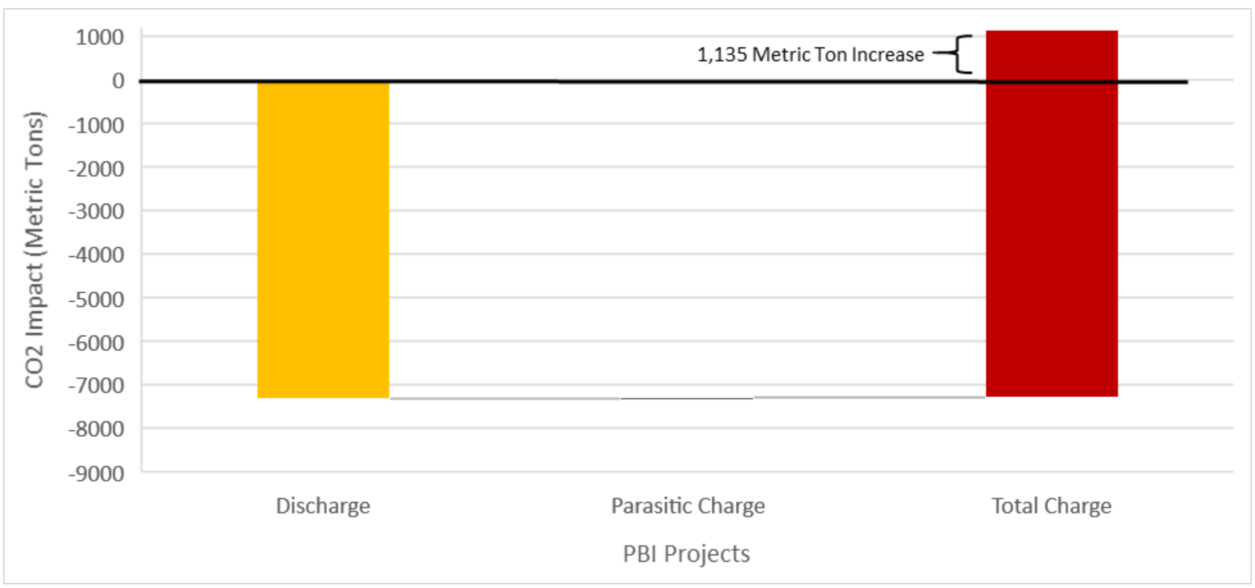


FIGURE 4-60: WATERFALL OF TOTAL CO2 IMPACTS FOR PBI PROJECTS (INCLUDING PARASITIC INFLUENCE)



The criteria pollutant grid marginal emission shape is derived from similar inputs as the CO_2 shape. Consequently, the results for SGIP AES criteria pollutant impacts are consistent with the CO_2 impact findings discussed above. Both PBI and non-PBI AES projects increased PM_{10} and NOx emissions due to the timing of their charge/discharge and increased energy consumption due to losses. Results are summarized in Figure 4-61 and Figure 4-62.

FIGURE 4-61: AVERAGE PM_{10} EMISSIONS PER REBATED CAPACITY FOR NONRESIDENTIAL PROJECTS

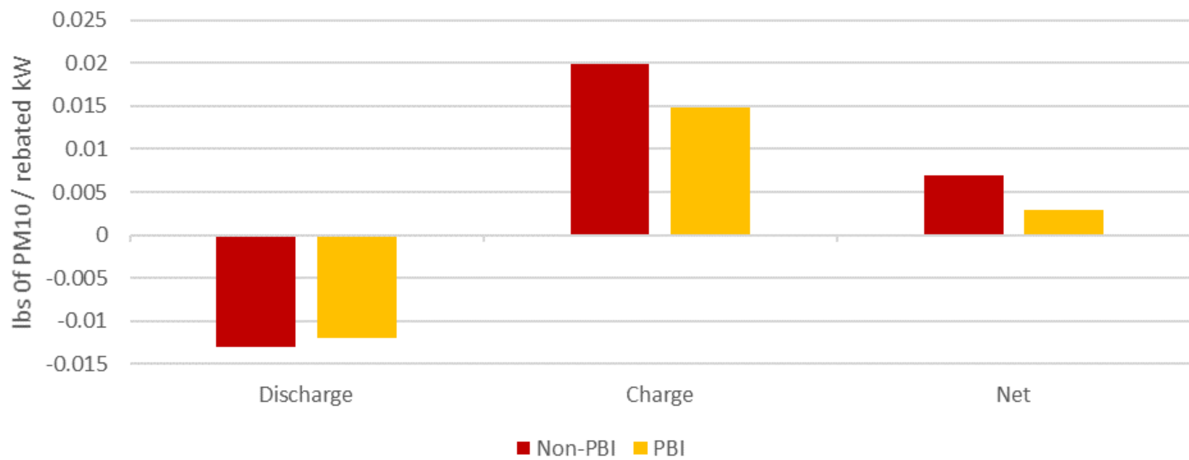


FIGURE 4-62: AVERAGE NOX EMISSIONS PER REBATED CAPACITY FOR NONRESIDENTIAL PROJECTS

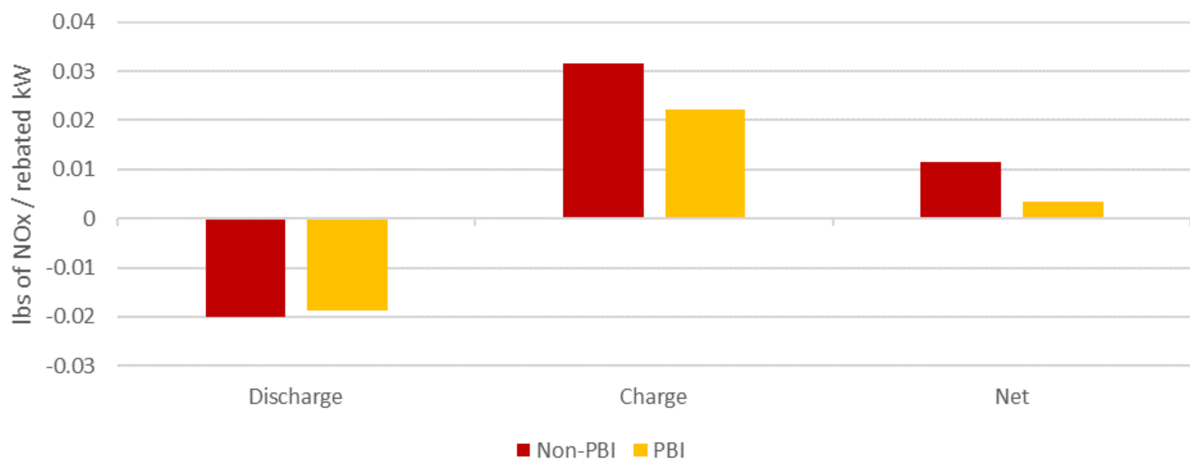


Figure 4-63 through Figure 4-66 display the average daily net discharge for non-PBI and PBI projects (for the summer and winter periods) along with the average marginal CO_2 emissions shape. In the summer, marginal emissions are highest during morning and late afternoon ramps (as renewable generation ebbs and demand increases). Non-PBI projects, on average, are charging more significantly throughout the late afternoon when marginal emissions are greatest. PBI projects are discharging consistently throughout the day and charging throughout the late night and early morning hours.

FIGURE 4-63: NON-PBI NET DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR SUMMER

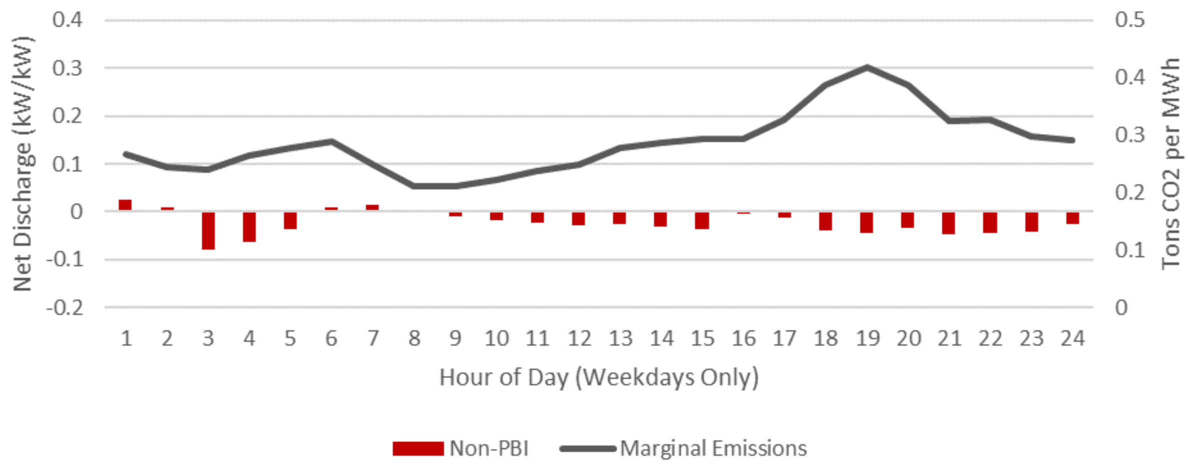


FIGURE 4-64: PBI NET DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR SUMMER

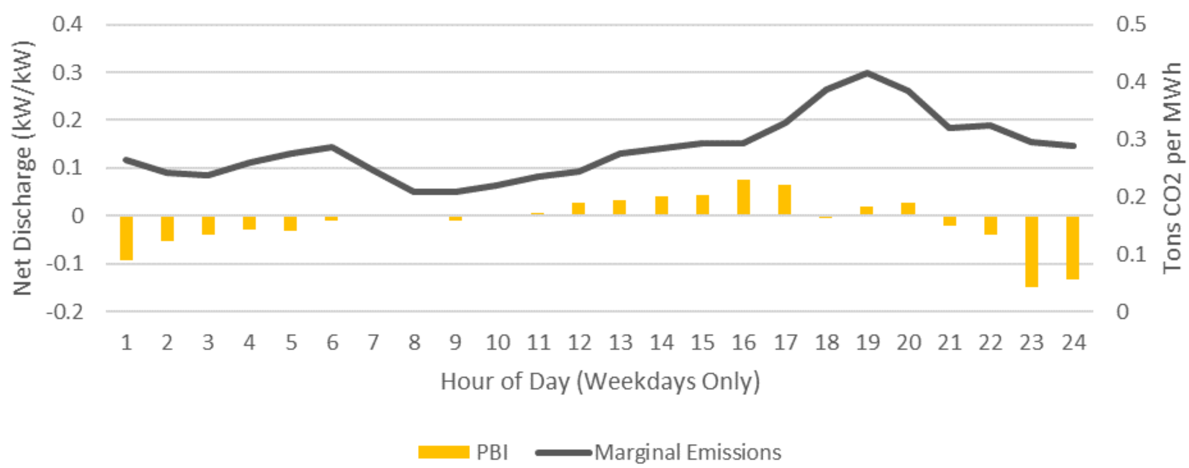


FIGURE 4-65: NON-PBI NET DISCHARGE PER REBATED KW MARGINAL EMISSIONS RATE FOR WINTER

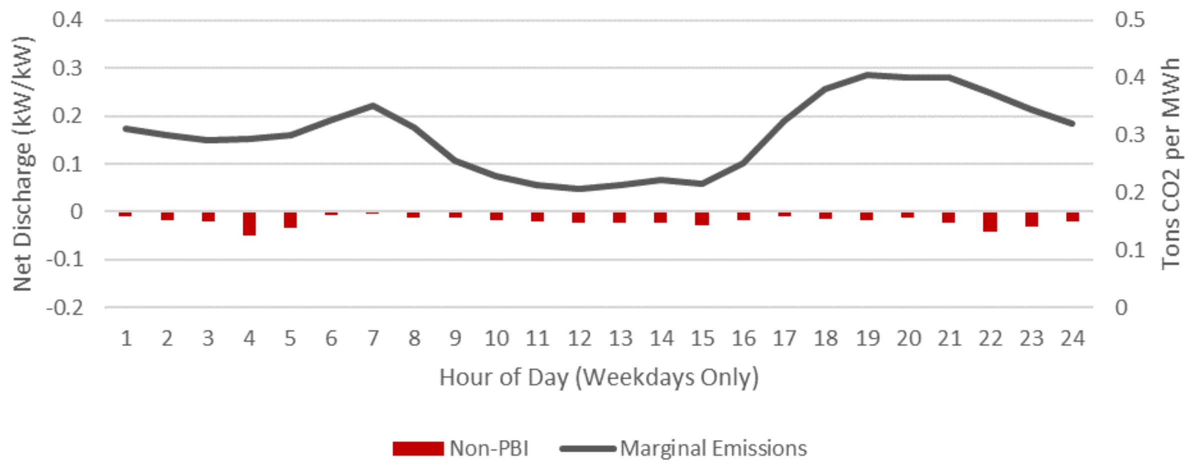
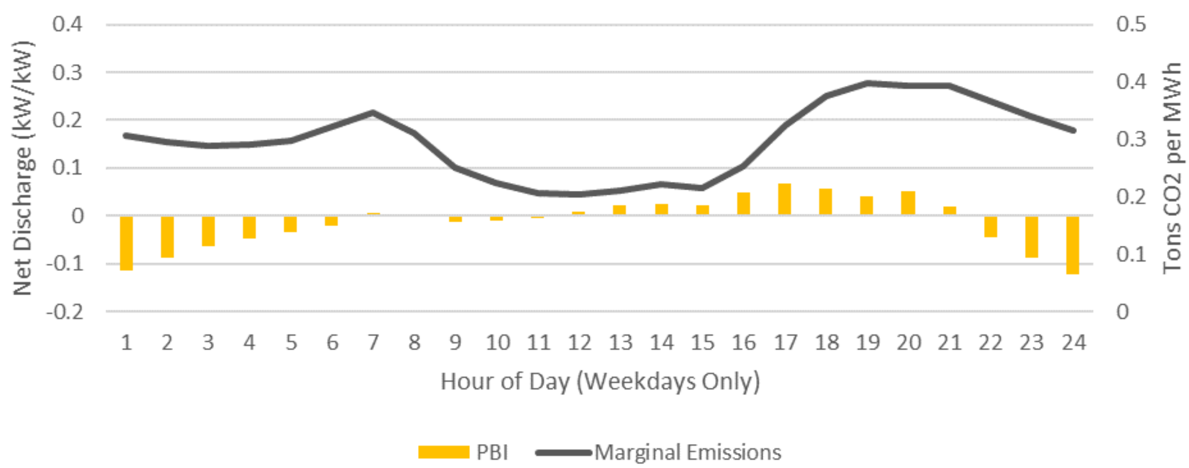
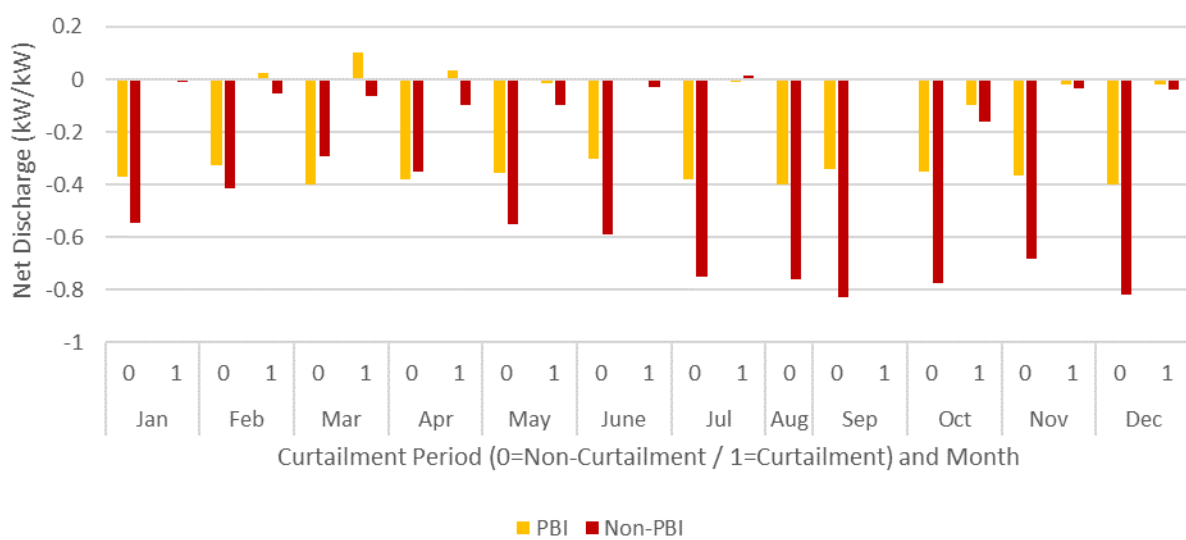


FIGURE 4-66: PBI NET KWH DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR WINTER



AES emission profiles are also impacted by the storage dispatch behavior during CAISO curtailment events. Given that the marginal emissions rates during these hours are zero, discharging during these hours will have no impact on overall GHG emissions. From a GHG minimization perspective, we would prefer that AES projects charge during these hours as they are "GHG free." This would contribute to GHG emission reductions while simultaneously providing grid integration benefits (increased load during curtailment events suggests storage dispatch is aligned with grid needs). We examined the discharge behavior for all projects in the sample by project type (non-PBI and PBI), month, and curtailment versus non-curtailment hours. We compared the average normalized net discharge for all curtailment hours within a month to non-curtailment hours for each project and developed an average net discharge value for PBI and non-PBI projects (kW per rebated kW). On average, both PBI and non-PBI customers are charging significantly less during curtailment hours relative to non-curtailment hours during any given month. In February through March, PBI systems are discharging during curtailment hours. This discharge may be providing customer benefits but is counter-productive from a GHG reduction and renewables integration perspective.

FIGURE 4-67: NET DISCHARGE KW PER KW BY MONTH AND CURTAILMENT EVENTS



4.5.2 Residential Environmental Impacts

The evaluation team has observed extremely different behavior in residential storage systems in 2018, compared to the 2017 impact evaluation, where all sampled residential projects contributed to an increase in GHG emissions. In 2017, we observed multiple factors that likely contributed to this result. First, sampled residential projects were idle during large portions of the year. This extended idle period led to an accumulation of parasitic loads which results in increased emissions. Second, the timing of charge/discharge was not well correlated with hours of high/low marginal emissions. This resulted in frequent charging during high emission hours. Finally, we observed that a significant portion of sampled residential energy storage systems began their cycling towards the end of the year when there are fewer high marginal emission hours that storage systems can benefit from.

As discussed throughout the report, there are well over 2,800 residential storage systems that received upfront payments in 2018. These projects represent a new fleet of sophisticated systems that are capable of operating in different modes – conducting PV self-consumption, TOU arbitrage, back-up, etc.

Figure 4-68 presents GHG impacts for the 284 sampled residential projects in 2018. Of the sample projects, 194 of them reduced GHG emissions as a result of their storage dispatch behavior. As evident in the below figure, there are also several systems that contributed an increase in GHG emissions by a small magnitude. Of the 32 projects that increased GHG emissions by greater than 0.01 MT per rebated capacity, 28 of them were legacy projects that were evaluated in 2017 and two are customer locations without onsite PV. While the legacy systems did improve performance in 2018 relative to 2017, the daily cycling and timing of charge and discharge still led to an increase in emissions.

FIGURE 4-68: NET CO2 EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS

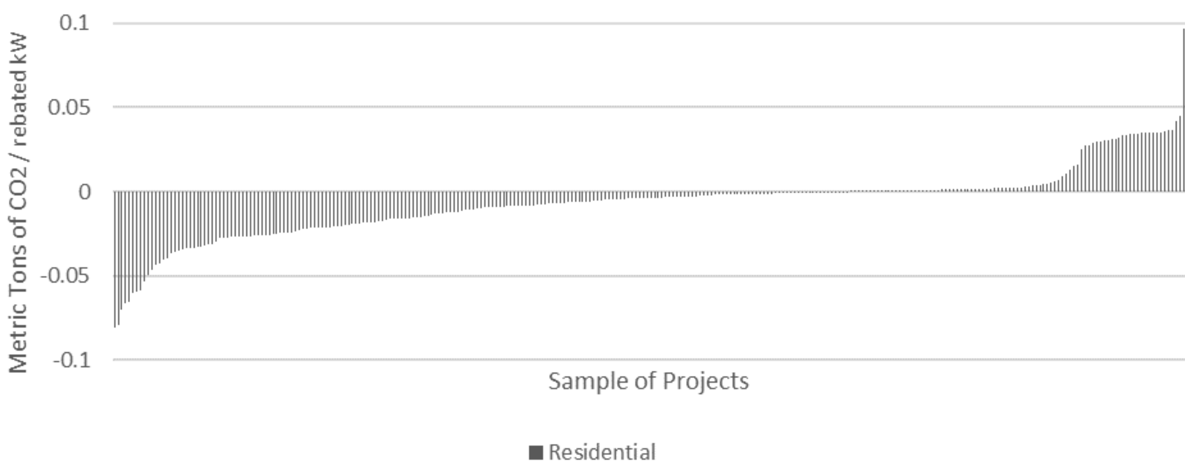


Figure 4-69 through Figure 4-71 summarize the average CO_2, PM_{10} and NOx impacts of residential energy storage systems. The average CO_2, PM_{10} and NOx emission impacts are highly correlated given the underlying assumptions used in development of all three emission profiles. We observed average decreases in emissions for all three pollutants.

FIGURE 4-69: AVERAGE CO2 EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS

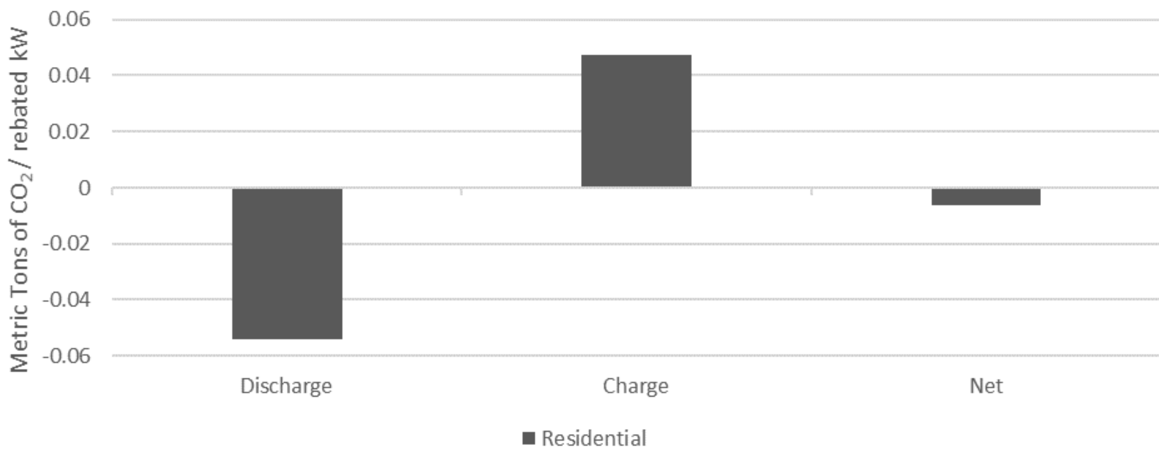


FIGURE 4-70: AVERAGE PM_{10} EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS

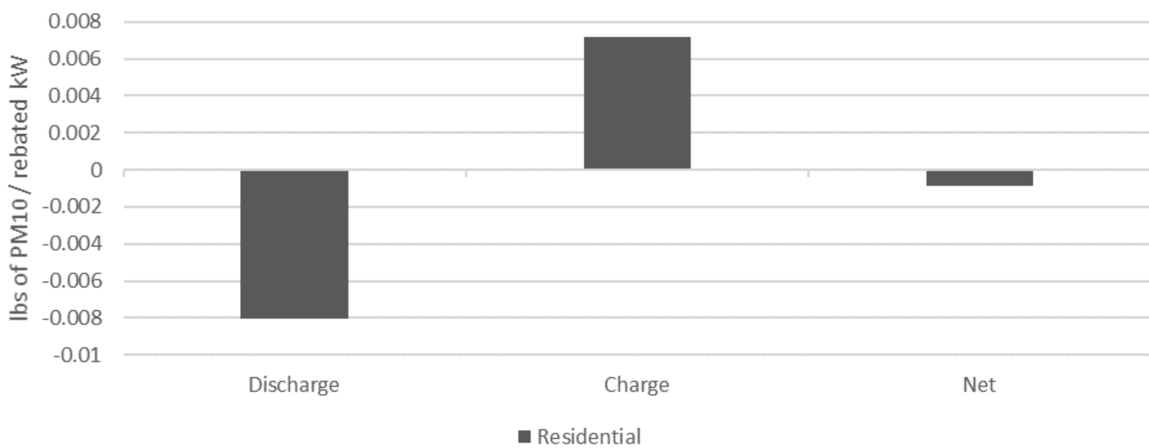


FIGURE 4-71: AVERAGE NOX EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS

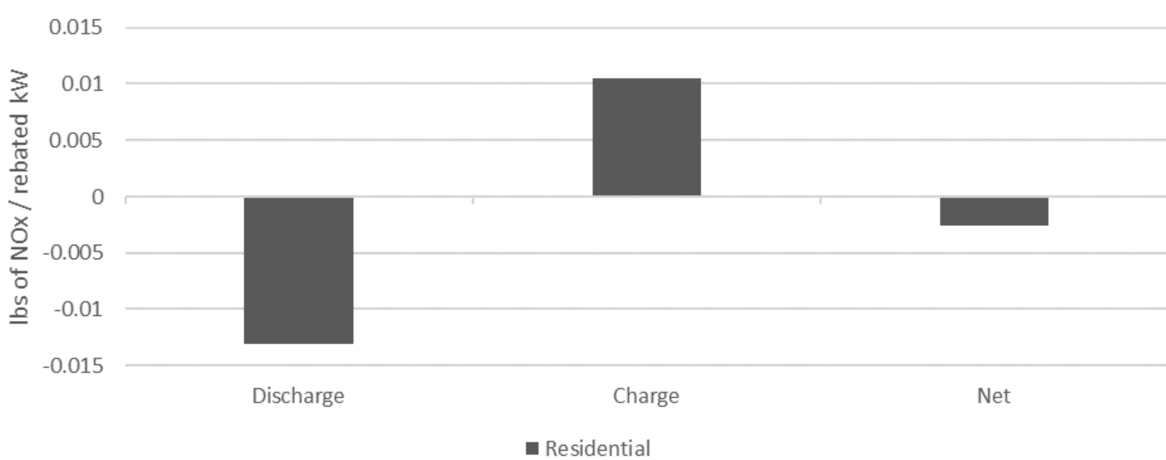


Figure 4-72 and Figure 4-73 display the average daily net discharge for residential projects (for the summer and winter periods) along with the average marginal CO_2 emissions shape and average onsite PV generation. For both summer and winter, marginal emissions are the lowest during the day when renewable generation is greatest and coincides with the average PV generation for residential SGIP storage projects. Again, residential systems are generally charging from PV during the morning hours and discharging later in the afternoon and early evening, which coincides with periods of higher marginal emissions.

FIGURE 4-72: RESIDENTIAL NET DISCHARGE PER REBATED KW MARGINAL EMISSIONS RATE FOR SUMMER

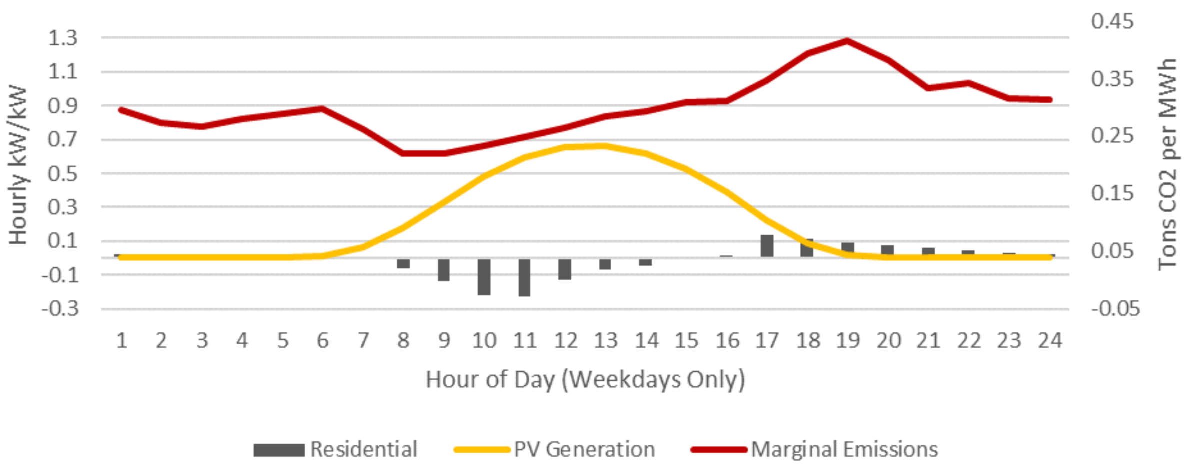
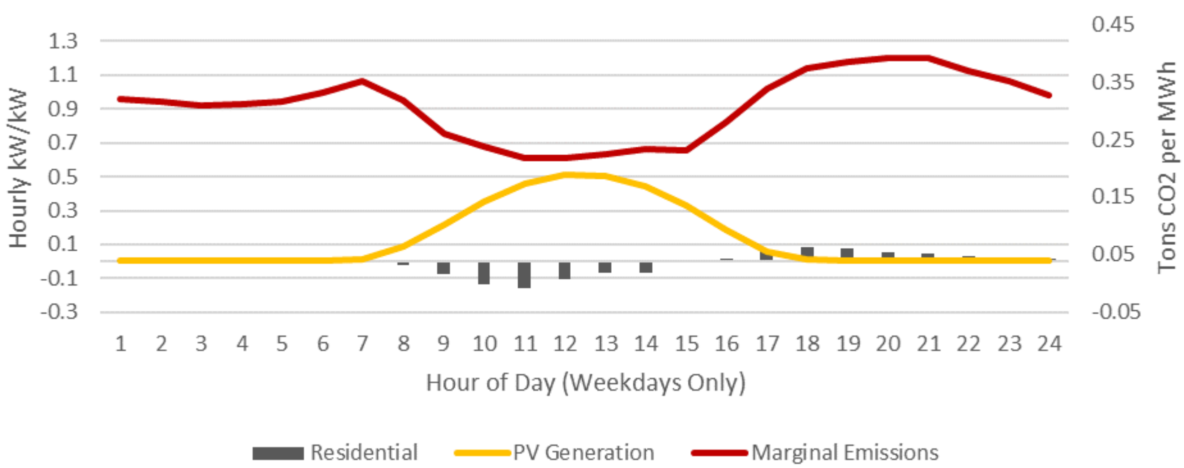


FIGURE 4-73: RESIDENTIAL NET DISCHARGE PER REBATED KW MARGINAL EMISSIONS RATE FOR WINTER



Finally, we provide a discussion of the relationship between a project's RTE or CF in relation to the amount of GHGs they are avoiding (-) versus the amount of incremental GHG they are contributing on the grid (+). Figure 4-74 and Figure 4-75 are similar to Figure 4-68 in that they present the project-specific emissions for each project evaluated in 2018. However, a few differences are of note:

- GHG emissions are presented in kilograms/kWh rather than MT/kW. Legacy systems are all 2-hour batteries and new systems range from 1.7 to 2.6 hours duration and kilograms are the MT x 1,000
- Four different project types are highlighted in the figure; 1) new storage projects with PV that are on a TOU rate, 2) new storage projects with PV that are on a traditional tiered rate, 3) new storage projects where there is no on-site PV generation and 4) legacy storage systems (those operating prior to 2018)
- The GHG impacts are charted along with the RTE and CF for each project

Overall, the legacy projects and stand-alone storage projects contribute to an increase in GHG emissions independent of the project RTE or CF. By and large, the new residential projects paired with on-site PV generators are GHG reducers. There also appears to be a positive relationship between increases in RTE and utilization and decreases in marginal GHG emissions. However, it's likely that the timing of charge and discharge contributes more to these GHG reductions than just increases in utilization alone. All systems are charging during early PV generation hours which generally occur during lower marginal emission hours and discharge in the afternoon and early evening when renewable generation on the grid wanes, electric demand increases and marginal emissions increase.

FIGURE 4-74: KILOGRAMS/KWH GHG INCREASE (+) DECREASE (-) FOR RESIDENTIAL PROJECTS VERSUS RTE

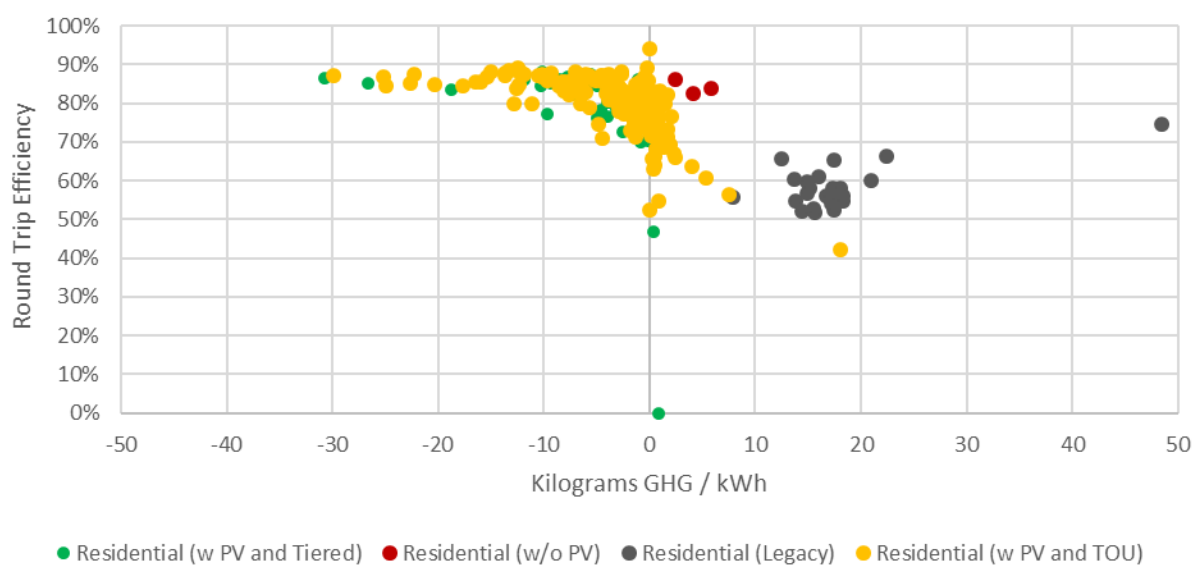
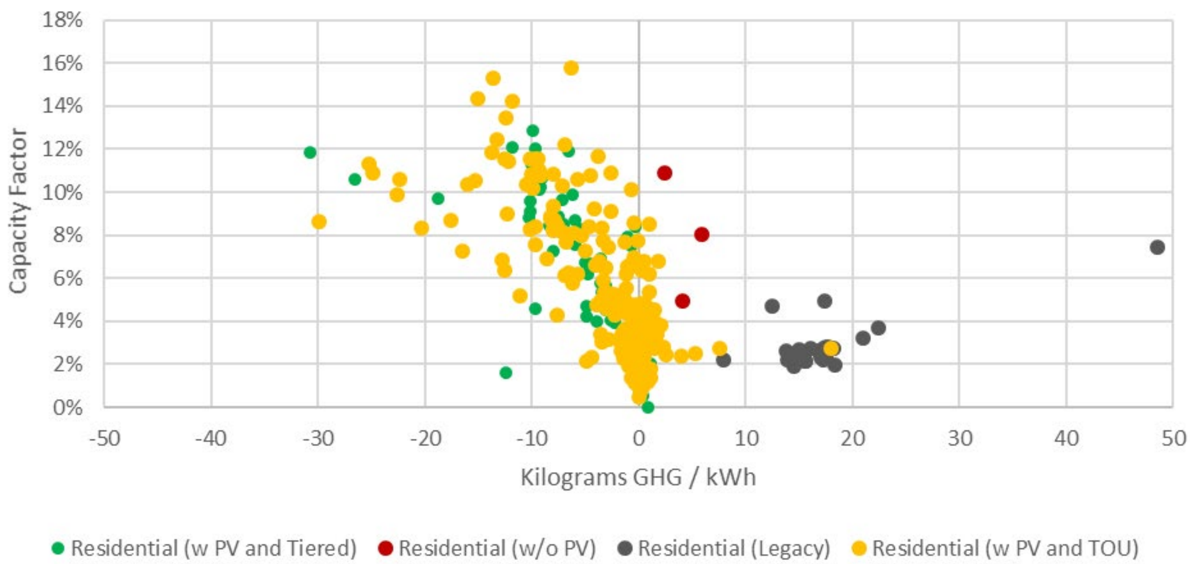


FIGURE 4-75: KILOGRAMS/KWH GHG INCREASE (+) DECREASE (-) FOR RESIDENTIAL PROJECTS VERSUS SGIP CF



4.6 UTILITY MARGINAL COST IMPACTS

Utility marginal cost impacts were calculated for each IOU and each hourly time increment in 2018. This analysis was conducted using 2018 avoided costs from the most recently CPUC-adopted avoided cost calculator.[21] Storage system charging results in an increased load and therefore will generally increase cost to the grid and discharging generally results in a benefit, or avoided cost, to the grid.

For AES projects 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 AES 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 projects 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 include energy, system capacity, renewable portfolio standard[22] (RPS), ancillary services ($/kWh) costs and distribution and transmission. Additional details on the marginal cost methodology and the assumptions made in developing a marginal cost dataset are included in Section 5. It is important to note that storage system operators are generally not aware of the cost of generating, transporting and supplying energy.

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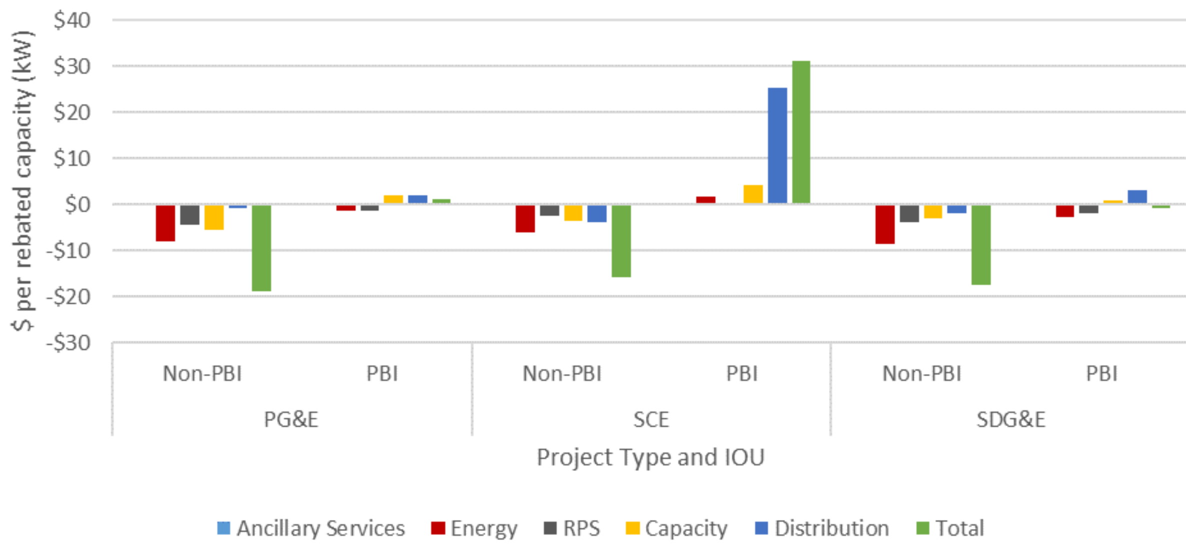
21 See CPUC D. 16-06-007 available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K338/163338441.PDF

22 Section 5 provides a detailed definition of RPS and all other marginal costs.

4.6.1 Nonresidential Utility Cost Impacts

The normalized utility marginal costs are shown in Figure 4-76 by electric IOU and project type (non-PBI and PBI). Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). Overall, the average marginal *avoided* cost (+) for PBI projects is $15.27 per rebated capacity (kW) and the average marginal cost (-) for non-PBI projects is $17.54 per rebated capacity (kW).

FIGURE 4-76: MARGINAL AVOIDED COST $ PER REBATED CAPACITY (KW) BY IOU AND PROJECT TYPE



Overall, non-PBI projects represent a net cost to the utility system. The marginal costs modeled in this study are highest when energy prices are high and the CAISO system load is peaking. Section 4.3 provided evidence that non-PBI projects are net charging, on average, throughout the year. In other words, these projects are charging during both low and high marginal cost periods. There is also evidence that non-PBI projects were charging during CAISO peak hours which represents a net capacity cost. These results are similar to 2017.

The biggest change in storage avoided cost from 2017 to 2018 is the significant avoided capacity and transmission/distribution costs in SCE. Most of this system cost value is captured in a small number of high-cost hours that are generation capacity and/or distribution capacity constrained. These hours generally align with peak CAISO and IOU system hours. Figure 4-48 and Figure 4-50 showed that one building type in particular – offices – was discharging significantly through capacity constrained hours. Most of these systems were operating in SCE.

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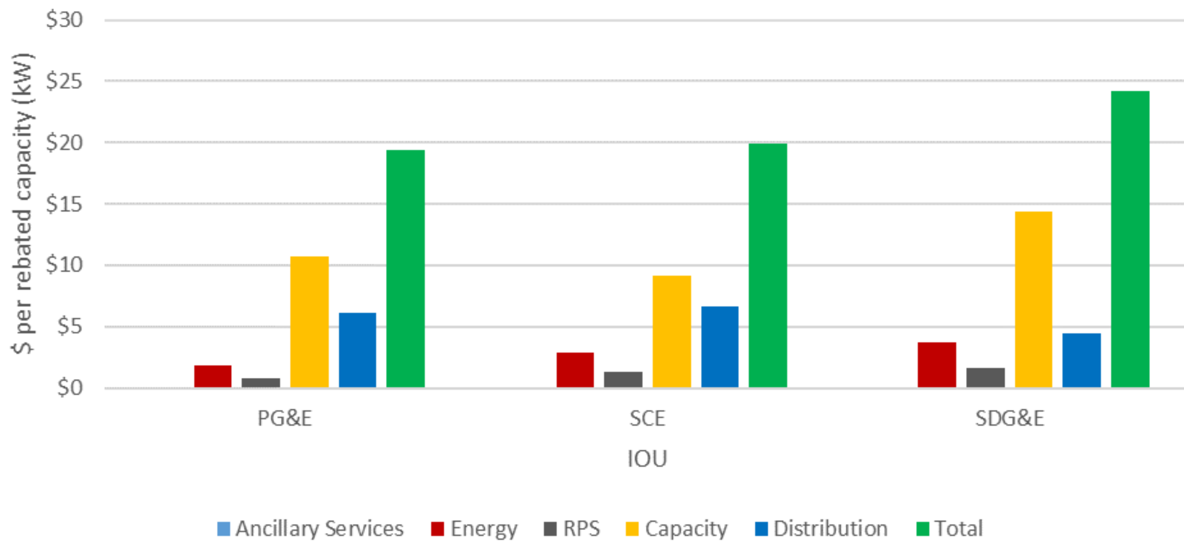
4.6.2 Residential Utility Cost Impacts

The normalized utility marginal costs are shown in Figure 4-77 for residential projects by electric IOU. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). The average marginal *avoided* cost (+) for residential projects is $20.54 per rebated capacity (kW).

FIGURE 4-77: MARGINAL COST $ PER REBATED CAPACITY (KW) BY IOU (RESIDENTIAL PROJECTS)



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 through low marginal cost periods and discharging in the early afternoon and evening during both high marginal cost and marginal emissions periods. These higher costs also align with the new residential TOU periods.

4.7 DEMAND RESPONSE PROGRAM IMPACTS

We examined storage dispatch behavior for customers participating in demand response (DR) programs. DR programs provide an incentive to customers to reduce (or shift) electricity consumption during periods of real (or perceived) high stress on the grid.[23] These programs are administered directly through utilities or through independent providers known as aggregators. They can be implemented as *day-of* events when there are either emergency constraints on system-level or local transmission and distribution networks or *day-ahead* events when forecasted high temperatures are expected to lead to

[23] There are also programs designed to incentivize customers to absorb load when there is an over-supply of electric generation on the grid.

periods of significant demand the following day. The motivation can take the form of an economic incentive (where a customer receives a monetary award) or a price signal (where a customer pays a higher energy rate during event periods). These incentives can represent a much sharper signal to customers to reduce demand than broad TOU rates which span several hours throughout the day. DR events are generally triggered for a shorter duration (sometimes at the sub-hourly level).

SGIP storage customers participated in a variety of DR programs throughout 2018. Below we provide a listing of the types of DR programs SGIP storage customers participated in during 2018:

- Critical Peak Pricing (CPP) and Peak Day Pricing (PDP)
- Capacity Bidding Program (CBP)
- Demand Response Auction Mechanism (DRAM)
- PG&E Supply-Side Pilot (SSP)
- PG&E Excess Supply Pilot (XSP)

Demand response programs are designed to motivate a reduction in electricity consumption during forecasted periods of high demand when energy prices are high and/or when there are emergency constraints on transmission and distribution networks, so beyond customer-specific benefits, they can provide significant benefits to the operation and maintenance of those systems. Likewise, since periods of high utility marginal costs associated with electricity delivery during periods of high demand often align with periods of high marginal GHG emissions, the appropriate demand reduction signals can provide a significant environmental benefit.

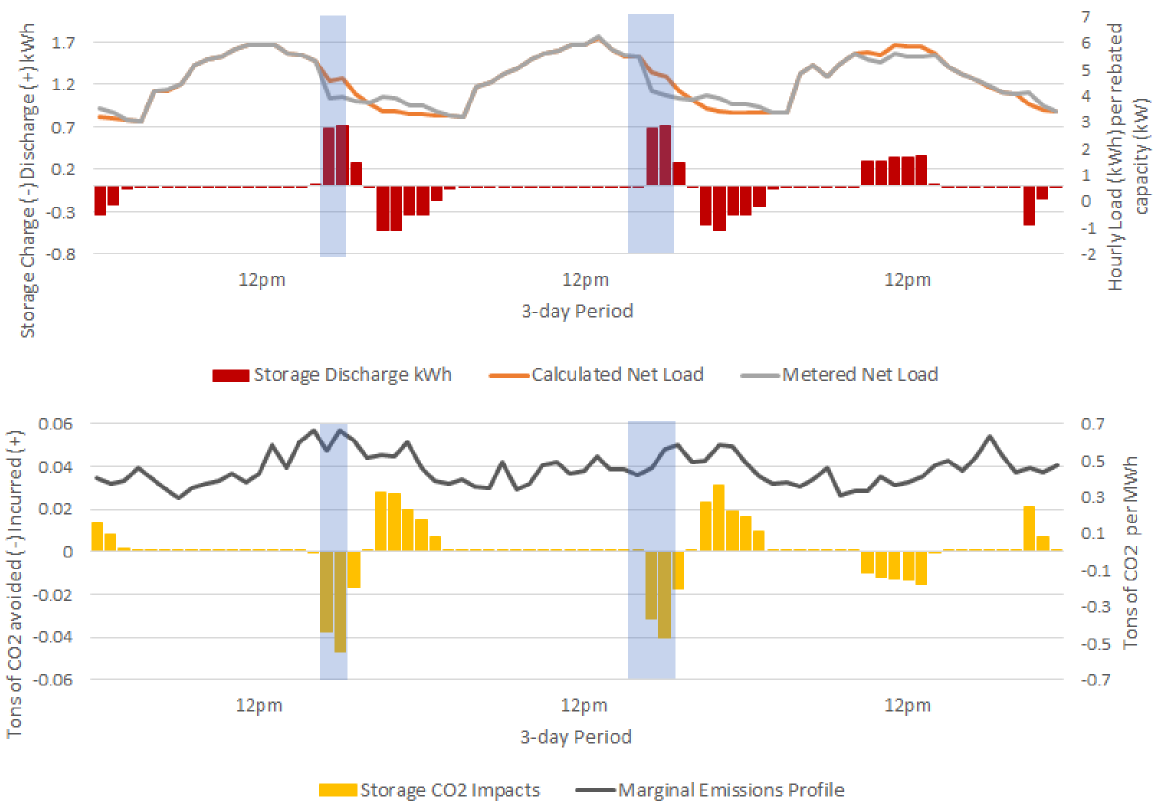
The evaluation team is unable to develop and present impacts of storage dispatch behavior for SGIP customers participating in DR programs due to small sample sizes. However, to illustrate how BTM storage responds to these types of programs and the importance of storage dispatch timing as it relates to GHG emissions and customer bill impacts, we present three case studies which are representative storage profiles of projects participating in DR programs.

Example 1

Figure 4-78 shows a three-day profile for a customer with energy storage enrolled in a DR program. In this example, a 2-hour DR event is called on the first day and a 4-hour event is called on the second day (highlighted in light blue). Storage discharge (+) and charge (-) are presented along with the normalized net metered load and the calculated gross load – the facility load that would have been observed in the *absence* of the storage system. The storage system discharges roughly 140 kWh throughout each of the DR event periods in the example, and charges later in the evening. On the first day, the DR event and storage discharge also coincide with a period of high marginal emissions which leads to a reduction in

GHG emissions during that period (in yellow on lower figure). The storage system then charges during a period of lower emissions. In this example, the storage system will have reduced GHG emissions on the first day. On the second event day, however, the storage system would contribute a net increase in emissions. The storage system discharges during the second 2 hours of the 4-hour event. However, marginal emissions are still high when the storage system charges later in the evening, leading to an increase in emissions. On the third day, without the DR signal, the storage system is programmed to manage facility peak demand and discharges throughout the day to shave peak loads. The utilization of the battery is identical on all three days. The difference is in the timing of dispatch.

FIGURE 4-78: EXAMPLE #1 OF DEMAND RESPONSE WITH STORAGE, LOAD AND GHG PROFILES

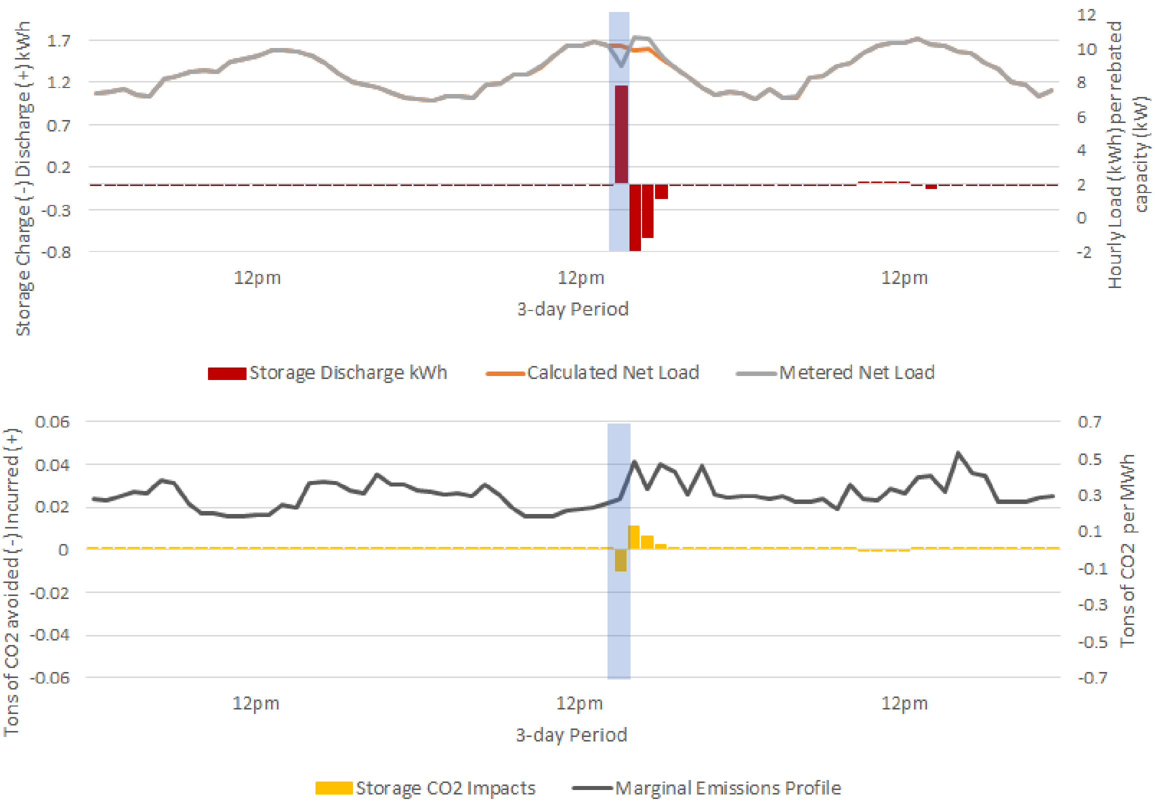


While the above example illustrates that storage systems participating in DR programs can provide GHG emission reductions, these benefits are predicated on a number of factors – the price signal of the DR event in relation to the opportunity cost of potentially missing peak demand reduction for that day, the pattern of storage charge and discharge in relation to facility load and the timing of periods where GHG emissions are higher or lower.

Example 2

Figure 4-79 provides an example of a different storage system responding to a DR event signal, but the pattern and timing of dispatch results in an increase in GHG emissions. In this 3-day example, a customer participates in a 1-hour DR event on the second day and the storage system is mostly idle on the first and third day. On the second day, the system discharges a significant percentage of system capacity throughout the hour to satisfy the event call and charges immediately thereafter. This leads to an increase in load for that day and an increase in GHG emissions because the timing of charge and discharge both coincide with high marginal emission periods. The "snap-back" effect of charge immediately following discharge contributes to those emission increases.

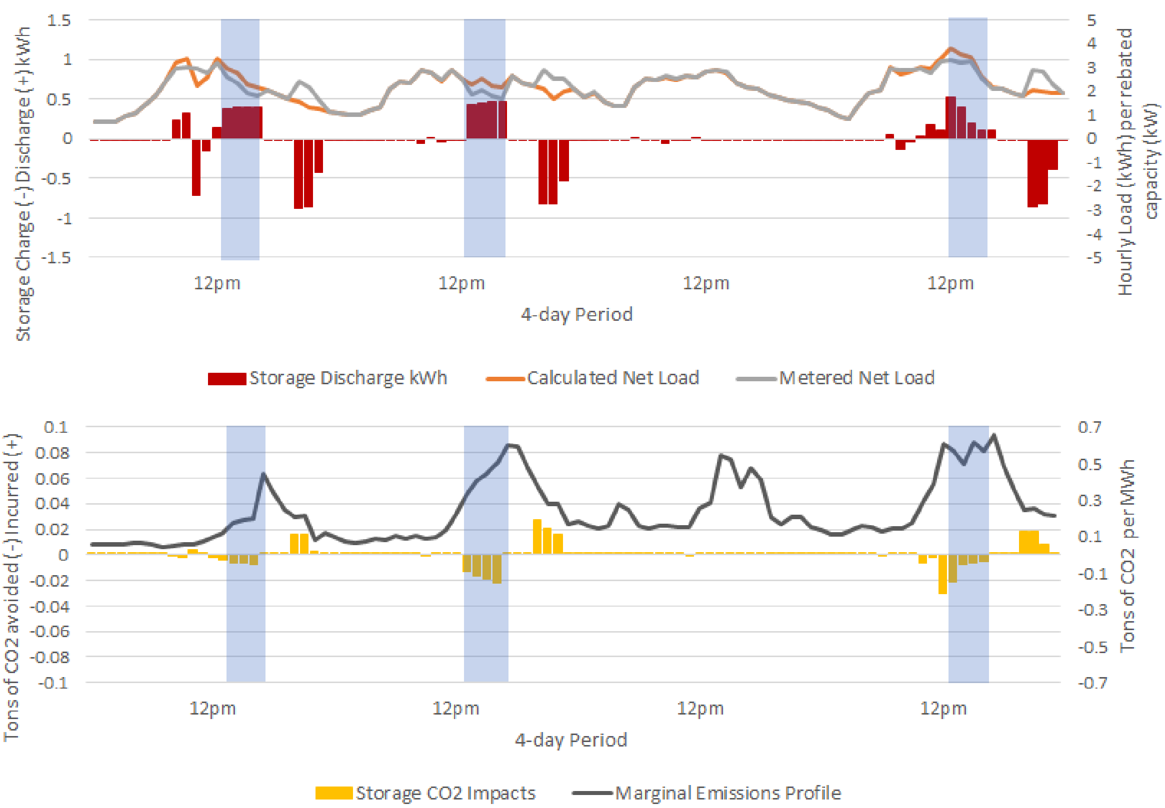
FIGURE 4-79: EXAMPLE #2 OF DEMAND RESPONSE WITH STORAGE, LOAD AND GHG PROFILES



Example 3

The final example represents a customer enrolled in critical peak pricing. This is an energy rate adder applied to a customer's tariff where customers are charged higher energy rates during event periods. These events are day-ahead TOU rate structured programs and are called based on either forecasted system emergencies, extreme temperature and/or CAISO alert/warnings. In this example, three 4-hour events (highlighted in blue) are called during this 4-day period. Figure 4-80 shows the storage system discharging in response to the three event periods, remaining idle for a few hours and charging later in the evening. On the second and fourth day, this system will have led to a decrease in GHG emissions because 1) the events coincided with high marginal emissions periods and 2) the storage system remained idle (instead of charging right away) and charged during late in the evening when emissions were lower. On the third day, the system contributes to an increase in emissions because it remains idle throughout the day and parasitic loads accumulate. The system also contributes to an increase in emissions on the first day (an event day) because the event is not perfectly aligned with the period of higher marginal emissions. From the customer perspective, they have decreased load during all three event periods and the storage system is sized (and programmed) to be capable of discharging throughout the entirety of the 4-hour event periods.

FIGURE 4-80: EXAMPLE #3 OF DEMAND RESPONSE WITH STORAGE, LOAD AND GHG PROFILES



4.8 POPULATION IMPACTS

The previous sections presented the analyses conducted to showcase the impacts of individual storage systems and samples of distinct customer segments (PBI vs non-PBI and residential vs nonresidential). These analyses were intended to highlight how SGIP storage systems were behaving in 2018 and how they were performing to meet program objectives. These analyses were all based on sampled projects 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 2018.

As presented in Section 3, the evaluation team attempted a census on all PBI projects given their significant contribution to overall program capacity. Our team also developed a dedicated random sampling approach on non-PBI projects – both residential and nonresidential. Section 3 provides more detail into how each of these samples were developed, but they are summarized below in Table 4-1. Overall, our team evaluated 632 projects receiving upfront payments prior to December 31st of 2018 and 86 MW of total program capacity. The sample represents 17 percent of the total population by project count and 77 percent of the total population capacity. Again, PBI systems represent the most significant percentage of the population – in terms of capacity – and have the greatest influence on overall SGIP population impacts.

TABLE 4-1: SAMPLE DISPOSITION OF SGIP STORAGE POPULATION BY CUSTOMER SECTOR

Customer Sector	Sample n	Population N	% of Projects Sampled	Sample Capacity (MW)	Population Capacity (MW)	% of Capacity Sampled
Nonresidential PBI	211	237	89%	79	84	94%
Nonresidential Non-PBI	137	302	45%	5	8	58%
Residential	284	3,242	9%	2	19	9%
Total	**632**	**3,781**	**17%**	**86**	**111**	**77%**

Below we summarize the population estimates for several program impact metrics for each customer sector along with the program total. Population project counts and relative precision levels are also reported in the tables and are based on a confidence level of 90 percent. Population estimates were calculated for the following in 2018:

- 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 and criteria pollutant impacts
- Utility Avoided Costs – total utility avoided costs

Total net discharge (i.e., the total energy impact that resulted from charging and discharging AES projects) during 2018 is summarized in Table 4-2. 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. PBI systems represent the most significant increase in total energy given their relative size. They also have the highest RTE (81 percent). The total energy impact was an increase in electric energy consumption of 7,671 MWh during 2018.

TABLE 4-2: ELECTRIC ENERGY IMPACTS

Customer Sector	N	Population Discharge (MWh)	Population Charge (MWh)	Population Net Discharge (MWh)	Population RTE	Relative Precision
Nonresidential PBI	237	25,119	31,010	-5,892	81%	4%
Nonresidential Non-PBI	302	1,706	2,748	-1,042	62%	8%
Residential	3,242	2,657	3,395	-738	78%	4%
Total	**3,781**	**29,482**	**37,154**	**-7,671**	**79%**	**3%**

CAISO system peak demand impacts are summarized in Table 4-3 (top hour). In 2018 the CAISO statewide system load peaked at 46,487 MW on July 25th during the hour from 4 to 5 PM PST. All three customer sectors provided a system benefit throughout that hour by net discharging a total of roughly 17.5 MWh throughout that period. Note that the project count below is less than the total population (as indicated in the table above). This estimate is based on all projects that were conducting normal operations on July 25th. A significant percentage of projects (mostly residential) received their upfront payment or began normal operations after this date in 2018. The poor relative precision reported for non-PBI (both residential and nonresidential) is largely a consequence of the small population estimate of total impacts and variability in project-specific storage dispatch behavior throughout the CAISO top hour.

TABLE 4-3: CAISO SYSTEM PEAK DEMAND IMPACTS (PEAK HOUR)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential PBI	183	16,571	8%
Nonresidential Non-PBI	282	608	34%
Residential	723	288	27%
Total	**1,188**	**17,467**	**8%**

The total impacts across the top 200 CAISO hours are presented below in Table 4-4. These results are consistent with the sample impacts presented in Section 4.4. While all three customer sectors were net discharging throughout the top hour, only residential and PBI customers were still providing that benefit across the top 200 hours. Overall, however, the population of systems provided a net benefit to the CAISO during those hours.

TABLE 4-4: CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 200 HOURS)

Customer Sector	N	Population Net Discharge (kW)	Relative Precision
Nonresidential PBI	190	1,225,370	7%
Nonresidential Non-PBI	284	-29,078	24%
Residential	1,186	40,909	22%
Total	**1,660**	**1,237,200**	**7%**

Greenhouse gas impacts during 2018 are summarized in Table 4-5. Greenhouse gas impacts for both PBI and non-PBI nonresidential are positive, reflecting increased emissions. The magnitude and the sign of greenhouse gas impacts is very dependent on the timing of AES charging and discharging. The residential sector, however, contributed to a decrease in GHG emissions throughout 2018. 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 4.5.2). Systems were either trying to maintain zero net load during these higher marginal emission hours or responding to TOU price signals. We observe similar results for NOx and PM_{10} impacts, as shown in Table 4-6 and Table 4-7.

TABLE 4-5: GREENHOUSE GAS IMPACTS

Customer Sector	N	Population Impact (MT CO_2)	Relative Precision
Nonresidential PBI	237	1,210	6%
Nonresidential Non-PBI	302	307	9%
Residential	3,242	-69	28%
Total	**3,781**	**1,448**	**6%**

TABLE 4-6: NO_X IMPACTS

Customer Sector	N	Population Impact (lbs NO_x)	Relative Precision
Nonresidential PBI	237	180	11%
Nonresidential Non-PBI	302	70	10%
Residential	3,242	-34	17%
Total	**3,781**	**216**	**10%**

TABLE 4-7: PM_{10} IMPACTS

Customer Sector	N	Population Impact (lbs PM_{10})	Relative Precision
Nonresidential PBI	237	194	6%
Nonresidential Non-PBI	302	46	9%
Residential	3,242	-8	34%
Total	**3,781**	**232**	**5%**

Utility marginal cost impacts during 2018 are summarized in Table 4-8. The evaluation found that PBI and residential projects provided a utility-level population benefit in excess of $2 million in avoided costs. These results are consistent with the analyses presented in Section 4.6. PBI and residential projects were generally discharging during hours that were capacity or distribution constrained, especially during the summertime. Overall, the population of SGIP storage provided a roughly $2.2 million benefit in avoided cost in 2018.

TABLE 4-8: UTILITY MARGINAL COST IMPACTS

Customer Sector	N	Population Impact (Avoided Cost $)	Relative Precision
Nonresidential PBI	237	-$2,010,331	8%
Nonresidential Non-PBI	302	$93,771	13%
Residential	3,242	-$342,174	13%
Total	**3,781**	**-$2,258,735**	**8%**

5 IDEAL DISPATCH OF SGIP AES PROJECTS IN 2018

This chapter describes analysis performed to quantify the *maximum* benefits that the SGIP storage projects could have potentially achieved in 2018, *assuming they were optimally dispatched* for different objectives with perfect information.

To calculate these maximum benefits, the evaluation team employed a short-term marginal cost approach using E3's RESTORE and DER Avoided Cost models. In this approach, storage is dispatched based on one of three dispatch approaches:

- For the Customer Bill Dispatch Approach, storage is dispatched to minimize a customer's monthly electricity bill
- For the System Cost Dispatch Approach, storage is dispatched to minimize the marginal cost of serving load at the system level
- For the Carbon Dispatch Approach, storage is dispatched to minimize both the customer's monthly electricity bill and marginal carbon dioxide emissions

For this analysis, our optimizations are executed on a monthly basis and assume perfect load and price foresight.

Per CPUC decision, the SGIP program is evaluated using 2018 avoided costs calculated using the most recently CPUC adopted avoided cost calculator.[1] Additional detail on this methodology is provided in Section 5.2 below.

5.1 DESCRIPTION OF SAMPLE DATA

The results presented in this section are based on modeling *idealized dispatch* of the AES projects that received SGIP incentives on or before December 31, 2018. They do not reflect the actual performance of the SGIP AES projects. Rather, they use AES capacity, customer load shapes, tariff information and demand response participation data from the sample of real AES projects, and ask how they *would* have performed in 2018 if they ideally responded to different signals based on perfect information.

The evaluation team received gross and net load shapes, battery sizes and tariff information for SGIP customers for simulation in our RESTORE analysis tool. In total 169 residential and 272 nonresidential had sufficient data to be modelled and were online for at least part of 2018. E3's model requires complete

[1] See CPUC D. 16-06-007 available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K338/163338441.PDF

tariff information and a load shape free of gaps in order to accurately produce optimized dispatch. Of the 441 AES projects in the sample, 405 of them had 15-minute load profiles with at least one missing value and 36 profiles had data gaps that exceeded two hours in duration. These gaps were filled to create complete profiles for use in RESTORE using CPUC standards for validating, editing, and estimating monthly and interval data.[2]

A significant number of new projects AES projects have been added since the 2017 analysis. Only 17 of the 169 residential customers and 189 of the 272 nonresidential customers were online on or before 1/1/2018. The remaining customers that came online mid-way through the year were only modelled from their date of normal operations onward.

As with the 2017 evaluation, the team has elected to use SGIP rebated capacity to model the storage systems. However rather than assigning a 2-hour duration to all systems, from analyzing actual storage discharge data it was found that many longer duration storage assets were included in the sample. Therefore, the duration used for modelling was derived by first taking the single largest discharge over 2018 for each customer and dividing this by rebated capacity to get a calculated minimum duration. This calculated duration was then rounded up to the nearest 2-hour interval with a 5 percent tolerance for measurement error. This resulted in 359 of the modelled systems having a 2-hour duration, 60 having a 4-hour duration, 6 with a 6-hour duration and 12 with an 8-hour duration.

As our analysis was conducted using a sample of AES projects rather than the entire population, the results had to be scaled up to estimate population-level impacts. The results from our sample were scaled to the SGIP AES population using the average impacts ($ or tons) per kW of rebated capacity for each sample strata (Section 3). The average impact for each strata was then scaled to the total kW of rebated capacity for each strata in the population. For storage systems that came online midway through 2018 only results after their online date were included and storage systems decommissioned or offline during the entire year were assigned zero impacts.

Since not all customers in the sample had sufficient data to be modelled in RESTORE, some strata did not have any customers in the final modelling sample and therefore the population impacts under ideal dispatch for those strata could not be estimated. The final modelling sample therefore was used to estimate impacts for 99.95 percent of nonresidential population storage capacity and 88.87 percent of

2 California Public Utility Commission (CPUC). 1999. Direct Access Standards for Metering and Meter Data (DASMMD); Attachment VEE—Standards for Validating, Editing, and Estimating Monthly and Interval Data; California Interval Data VEE Rules, Revision 2.0. March 1999. https://www.pge.com/includes/docs/pdfs/mybusiness/customerservice/startstop/newconstruction/greenbook/dasmmd.pdf

residential population storage capacity. Table 5-1 summarizes the sample size used for simulations relative to the population.

TABLE 5-1: SIZE AND REBATED CAPACITY CONTAINED IN NONRESIDENTIAL SAMPLE VERSUS POPULATION

	Nonresidential AES Modelling Sample	Nonresidential AES Population	Residential AES Modelling Sample	Residential AES Population
Number of Modeled Projects	272	539	169	2,835
kW of Rebated Capacity Associated with Modeled Projects	70,038	91,967	1,221	16,897

5.2 SIMULATING IDEAL DISPATCH: METHODOLOGY

To quantify the maximum potential value of SGIP AES in 2018, AES dispatch was optimized using E3's RESTORE model. RESTORE assesses the value of behind-the-meter (BTM) storage under different tariff, incentive and regulatory conditions. A high-level description of RESTORE is presented in this section. For further technical details, see the California Solar Initiative (CSI) PV Integrated Storage Report published on August 26, 2016, where the model is referred to as the "optimization model for SIS storage dispatch".[3] This model has also been developed further as part of the CEC EPIC-funded project EPC-17-004: Enhanced Modeling Tools to Maximize Solar + Storage Benefits. The CEC project is funding development of a solar + storage tool that incorporates other DER and uses Local Net Benefits Analysis (LNBA) methodology to quantify local distribution benefits. The IOUs plan to use a version of the model for Distribution Deferral Opportunity Reports (DDOR) filings due in September under the CPUC Distribution Resources Plans (DRP) proceeding.[4] A public version of the full model was released as the "Solar + Storage Tool" in August of 2019.[5]

The evaluation team used the specifications of each AES project in the sample (capacity, roundtrip efficiency and duration) as inputs to the RESTORE model, as well as each customer's load profile, utility rate schedule, and PV generation.

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[3] California Solar Initiative, "PV Integrated Storage: Demonstrating Mutually Beneficial Utility-Customer Business Partnerships." August 2016. http://calsolarresearch.ca.gov/images/stories/documents/Sol4_funded_proj_docs/E34_Cutter/4_CSI-RDD_Sol4_E3_PV-Integrated-Storage_FinalRpt_2016-08.pdf

[4] See CPUC D. 18-02-004 issued February 15, 2018 in CPUC R. 14-08-013, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K858/209858586.PDF

[5] California Energy Commission, "Modeling Tool to Maximize Solar + Storage." August 2019. https://ww2.energy.ca.gov/research/mod_tool_max_solar_storage/documents/

The evaluation team also developed an hourly kWh estimate of parasitic charge for each storage project. These values were ranged from 0 to 11.8 percent of rebated capacity on average across the year, depending on the project, with a median of 0 percent for all but 7 projects. The remaining 7 had high parasitic losses between 22 – 57 percent. These parasitic charges decrease the annual roundtrip efficiency of each project and was included in our RESTORE modeling as a constant, average contribution to the state of charge for each project. All results in this chapter therefore account for parasitic charges.

Under current SGIP eligibility requirements for energy storage, nonresidential projects must have a ten-year average roundtrip efficiency (RTE) of at least 66.5 percent and cycle at least 130 times per year, while residential projects also must have a roundtrip efficiency of at least 66.5 percent but cycle only 52 times per year.[6] These cycling requirements were included as a constraint in RESTORE for all AES projects in our sample that could meet the RTE requirement. For any AES project with an RTE below the required limit, no cycling constraint was added since the project would already be ineligible and would therefore have no incentive to meet the cycling requirement. 186 commercial and 165 residential customers had sufficiently high RTE's to have cycling requirements included.

For this analysis, RESTORE optimally dispatched each AES project in the sample three times to minimize impacts from three distinct dispatch approaches as described below.

Customer Bill Dispatch

The objective of the Customer Bill Dispatch was to dispatch the AES project to minimize the customer's aggregated energy and demand charges under the utility rate schedule applicable to each AES customer in 2018. We obtained rate information from the IOUs' tariff sheets.

In the modelling sample all 272 nonresidential customers were on a time-of-use (TOU) tariff that included a demand charge. Of the 169 residential customers 118 were on a time-of-use tariff, none of which included a demand charge. The TOU periods for the 3 IOUs are described in Section 4.3.1. Twelve percent of nonresidential customers were on a tariff that included a real-time pricing (RTP) or critical-peak pricing (CPP) component. Under RTP, the hourly energy rates applicable on a day depend on the maximum temperature recorded on the previous day. Under CPP, customers get energy at a lower rate compared to the non-CPP baseline. In return, they are expected to participate in demand response events that can be called for a certain number of times across a year. Failure to maintain demand below permissible levels during the demand response event can result in a considerably higher energy charge.

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6 See CPUC D. 12-11-005 available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K260/310260347.PDF

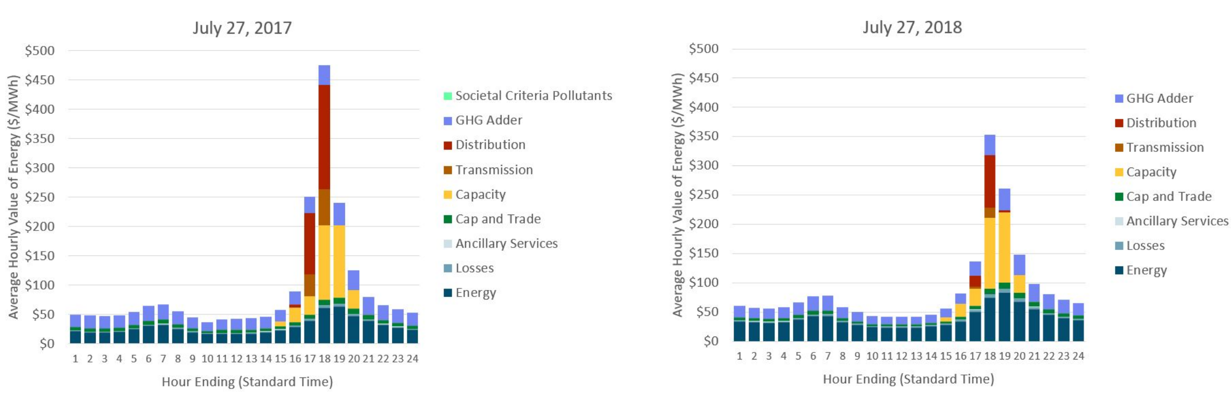
As described in Section 4.7, considerably fewer customers participated in demand response programs compared with the 2017 analysis. The 2018 modelling sample contained 6 customers in the Demand Response Auction Mechanism (DRAM), 8 customers in Capacity Bidding Program (CBP), 12 customers on PG&E's Peak Demand Pricing (PDP) program and 4 customers on SCE's Critical Peak Pricing (CPP) program. It was determined that sample size for the CBP and DRAM programs was insufficient to perform meaningful analyses, so these demand response programs were therefore excluded and instead customers were only dispatched to minimize bill savings under the customer bill dispatch approach. Since the PDP and CPP programs are peak pricing tariffs they could easily be modelled in RESTORE and were therefore included in the analysis.

System Cost Dispatch

Under System Cost Dispatch, storage was dispatched to minimize costs to the electric system. An increase in load generally results in an incurred cost to the system while reduced load generally results in an avoided cost, or net benefit, to the system.

Marginal costs were calculated for each IOU and each hourly time increment in 2018. The marginal costs used in our analysis are developed using 2019 DER Avoided Cost Calculator (ACC) developed by E3 and adopted by the CPUC.[7] The 2019 ACC contains several 'minor' updates from the 2018 calculator, primarily from updated inputs and price forecasts. The 2019 DER ACC has avoided costs for 2019 forward. In order to show the updates to the ACC and to highlight the differences between the two consecutive years, Figure 5-1 displays the avoided costs across 24 hours in PG&E's territory in Climate Zone 12. The monthly averages across the entire year are shown in Figure 5-2 for the same climate zone.

FIGURE 5-1: COMPARISON OF HOURLY AVOIDED COSTS BETWEEN 2017 AND 2018 ACROSS ONE DAY



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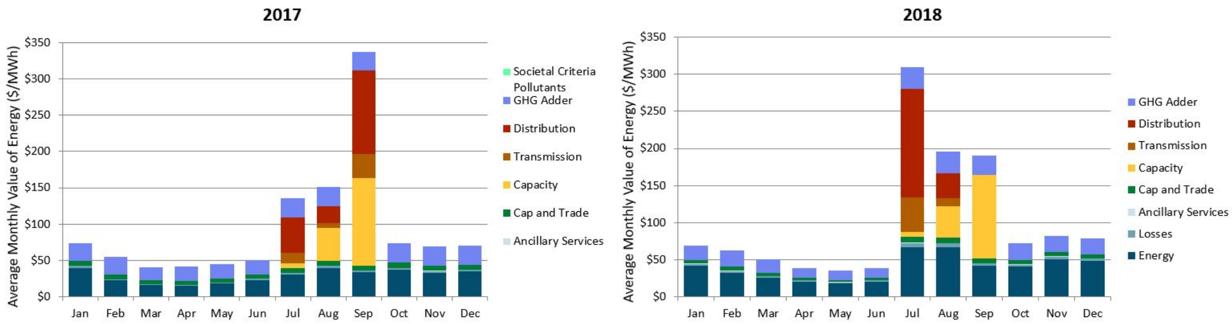
7 2018 DER Avoided Cost Calculator and Documentation available at: http://www.cpuc.ca.gov/General.aspx?id=5267

FIGURE 5-2: COMPARISON OF AVERAGE MONTHLY AVOIDED COSTS BETWEEN 2017 AND 2018



As for the 2018 SGIP analysis, E3 input historical 2018 prices in the DER ACC where appropriate to calculate 2018 avoided costs with the most recently adopted CPUC DER ACC model. The marginal cost categories included in this analysis are listed in Table 5-2.

TABLE 5-2: SYSTEM MARGINAL COSTS CONSIDERED FOR ANALYSIS

Marginal Cost Type	Data Source
Energy ($/kWh)	CAISO OASIS Day-Ahead location-based marginal prices, NP-15 and SP-15[8]
Losses	E3 Avoided Cost Calculator, by IOU
System Capacity ($/kW-yr)	E3 Avoided Cost Calculator, by IOU
Transmission ($/kW-yr)	E3 Avoided Cost Calculator, by IOU and climate zone
Distribution ($/kW-yr)	E3 Avoided Cost Calculator, by IOU and climate zone
RPS Prices ($/kWh)	E3 Avoided Cost Calculator, by IOU
Ancillary Services ($/kWh)	0.6% of energy prices (This assumption is consistent with the E3 Avoided Cost Calculator)

In response to stakeholder input, the 2019 DER ACC had different inputs for calculating the implied market heat rates, which impact the calculation of greenhouse gas (GHG) emissions. The minimum heat rate assumed for the most efficient natural gas plants is assumed to be 6,900 Btu/kWh. In the 2018 DER ACC, an implied market heat rate below 6,900 Btu/kWh was assumed to reflect renewable generation on the margin and have zero marginal GHG emissions. In the 2019 DER ACC, the lower heat rate is set to 0 Btu/kWh, removing the 6,900 Btu/kWh lower bound. This is intended to reflect a mix of natural gas and renewable generation on the margin at implied market heat rates below 6,900 Btu/kWh. The impact of this update is that hours with low prices and low implied market heat rates that had zero marginal GHG emissions in 2018 DER ACC will have some marginal GHG emissions in the 2019 DER ACC. Hours with

8 CAISO Open Access Same-time Information System: http://oasis.caiso.com/mrioasis/logon.do

negative market prices are assumed to have zero marginal GHG emissions in both the 2018 and 2019 DER ACCs.

Consistent with previous avoided cost analyses performed by E3, the marginal cost of energy generation is based on the locational marginal prices of the zone where the AES project is situated (NP15 for PG&E; SP15 for SCE and SDG&E). The 2018 $/kW-year marginal cost of generation capacity is taken from the 2019 DER Avoided Cost Calculator (see Table 5-3). Note that per CPUC methodology, the capacity costs reflect the full Cost of New Entry (CONE) for a new capacity resource. The CONE is higher than the cost of capacity currently paid by utilities in the annual Resource Adequacy (RA) procurement mechanism.

TABLE 5-3: $/KW-YEAR MARGINAL COST OF GENERATION CAPACITY

IOU	2018 Marginal $/kW-year of Generation Capacity
PG&E	$104.70
SCE	$102.42
SDG&E	$102.09

The marginal capacity cost is allocated across the 15-minute time intervals of the year using a peak capacity allocation factor (PCAF) method.[9] 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.

The $/kW-year marginal cost of transmission is also allocated using the PCAF method; specific values used are provided in Table 5-4. The 2019 Avoided Cost Calculator transmission capacity values come directly from the three IOUs. For PG&E, transmission and distribution marginal cost data was available at the climate zone level and is therefore used in the analysis. SDG&E reports a value of $0/kW-year because it does not have a sub-transmission system and therefore has no marginal cost value for transmission capacity.

9 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.

TABLE 5-4: $/KW-YEAR MARGINAL COST OF TRANSMISSION CAPACITY

IOU	2018 Marginal $/kW-year of Transmission Capacity
PG&E Zone CZ1	$8.17
PG&E Zone CZ2	$8.55
PG&E Zone CZ3A	$8.35
PG&E Zone CZ3B	$9.27
PG&E Zone CZ4	$8.48
PG&E Zone CZ5	$8.02
PG&E Zone CZ11	$8.69
PG&E Zone CZ12	$7.79
PG&E Zone CZ13	$8.54
PG&E Zone CZ16	$8.19
SCE	$43.09
SDG&E	$0

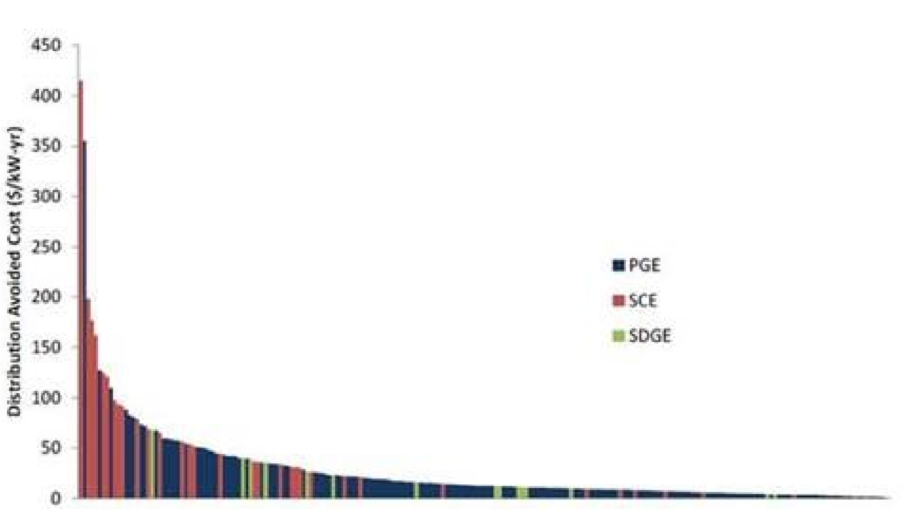
We use marginal distribution costs from the 2019 Avoided Cost Calculator, which are calculated from IOU general rate case filings. The $/kW-year distribution costs in the Avoided Cost Calculator represent the load growth related transmission and distribution capital investments that could be deferred with distributed energy resources that reduce peak loads.

TABLE 5-5: $/KW-YEAR MARGINAL COST OF DISTRIBUTION CAPACITY

IOU	Assumed 2018 $/kW-year of Distribution Capacity
PG&E Zone CZ1	$97.07
PG&E Zone CZ2	$49.13
PG&E Zone CZ3A	$48.58
PG&E Zone CZ3B	$28.09
PG&E Zone CZ4	$65.36
PG&E Zone CZ5	$76.16
PG&E Zone CZ11	$52.52
PG&E Zone CZ12	$40.89
PG&E Zone CZ13	$61.34
PG&E Zone CZ16	$73.11
SCE	$133.61
SDG&E	$111.35

In reality, marginal distribution costs can vary widely even within each climate zone, based on the load carrying capability, load growth and type of solution to address capacity deficiencies in each distribution area. For example, Figure 5-3 shows marginal distribution costs by planning area for the three IOUs from 2012. A limited number of locations have a high value above $110/kW-Yr., whereas most locations have a value below $60/kW-Yr.

FIGURE 5-3: MARGINAL DISTRIBUTION COSTS BY PLANNING AREA[10]



To capture this variation, E3 performed a distribution cost sensitivity. This involved using a low marginal distribution cost of $20/kW-year, and a high value case of $250/kW-year. The results of this are shown in Section 5.3.4.

Carbon Dispatch

For the Carbon Dispatch, storage is dispatched to reduce carbon dioxide emissions. In the 2017 study, this was achieved by optimally dispatching storage against a marginal carbon dioxide emission rate without regard for the customer's retail rate. For the 2018 analysis, the evaluation team implemented a new approach using a carbon price to co-optimize dispatch with the customer's retail rate and a carbon price adder. The carbon price signal is equal to the hourly marginal carbon dioxide emission rate multiplied by the societal carbon cost. Co-optimizing AES dispatch to minimize both the customer bill and a carbon price adder best illustrates how AES dispatch can be improved to reduce GHG emissions with minimal or no impact on the customer's bill. For example, within a given TOU period where the customer's rate is the same, a given kWh quantity of AES charge or discharge can be modified to increase GHG savings without any impact to the customer bill.

[10] Energy and Environmental Economics (2012). *Technical Potential for Local Distributed Photovoltaics in California*, March. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7695

E3 calculated the marginal rate of carbon emissions using the historical avoided cost model method adopted by the CPUC. We used 5-minute real-time market price data as recommended by the CPUC GHG working group.[11] This methodology assumes that natural gas is the marginal fuel in all hours. The emissions rate of the marginal generator is calculated based on the real-time market price curve (with the assumption that the price curve also includes the cost of CO_2):

$$HeatRate[h] = (MP[h] – VOM) / (GasPrice + EF * CO_2Cost)$$

These prices and implied emissions rates vary between northern and southern California. Thus, PG&E has one assumed marginal emissions rate, and SDG&E and SCE have another. As described in the System Cost Dispatch section, particularly high or low market prices may not be a direct reflection of marginal emissions rates and can reflect other factors in the market such as transmission constraints or unplanned outages. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of natural gas technologies as shown in Table 5-6.

TABLE 5-6: BOUNDS ON ELECTRIC SECTOR CARBON EMISSIONS USING AVOIDED COST CALCULATOR METHODOLOGY

Baseline	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate(Btu/kWh)	12,500	0

The 15-minute marginal emission rate was then multiplied by the societal cost of carbon from the Avoided Cost Calculator of $63.01 /short ton to get a 15-minute marginal emission price signal in units of $/kWh. This price signal was combined with the customers' electric tariff under the carbon dispatch approach to co-optimize for both emissions and bill savings. As described in the customer bill dispatch section, many customers in the sample were on time varying utility rate schedules. Figure 5-4 shows the resulting price signal when combining an example TOU tariff with the carbon price signal on a given day.

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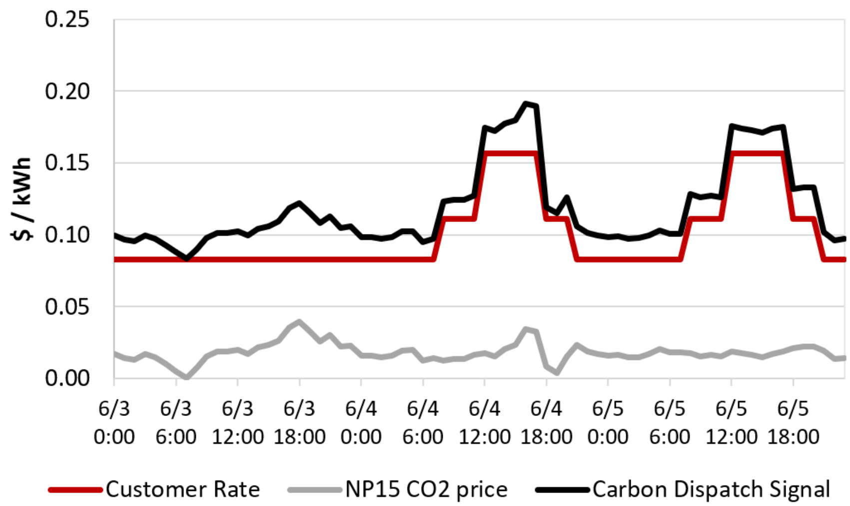
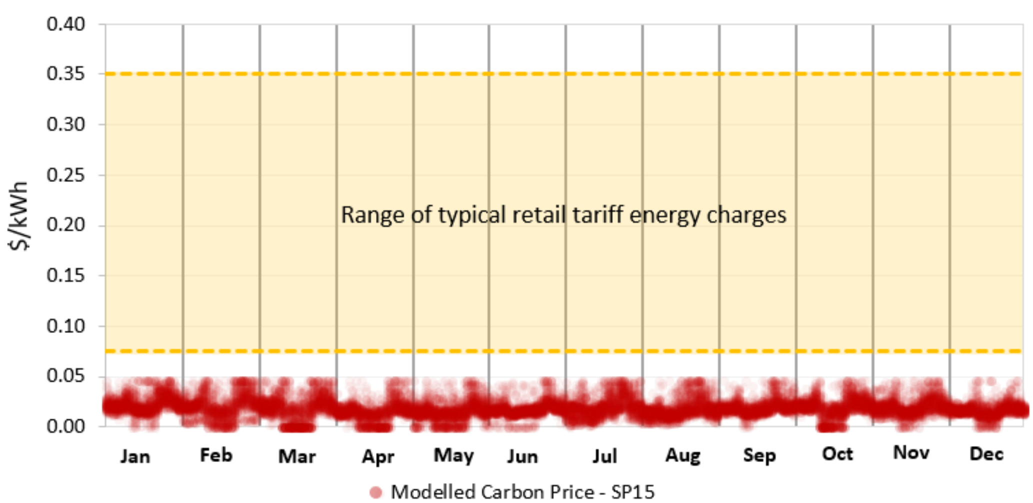
[11] See SGIP GHG Signal Working Group Final Report issued June 15, 2018, available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457832. Empirical observations of curtailment events suggest that they are addressed far more often in the real-time market than the day-ahead market. Additionally, as AES projects are not under any hard constraint for operations, and the total storage capacity of AES projects compared to system-level load is small, system operators are unlikely to depend on any shifts in load as a firm behavior that bears influence in the day-ahead market. Because we are interested in the marginal impact of SGIP, any alteration in electricity demand attributed to SGIP is likely to be addressed in real-time, rather than in the day-ahead market. For these reasons, the market signal underlying the marginal emissions rate methodology was changed from the day-ahead to the real-time energy market.

FIGURE 5-4: EXAMPLE CARBON APPROACH DISPATCH SIGNAL FOR A NONRESIDENTIAL PG&E CUSTOMER FROM SUNDAY JUNE 3RD - TUESDAY JUNE 5TH



As the figure highlights, the carbon price signal is small in comparison to the tariff, plotting all weekday hourly prices onto a 288 seasonal chart further illustrates the relative size of the carbon price signal compared to the typical range for retail energy charges (yellow highlighted region). Note the price is clearly bounded by the heat rate as previously described and there is not significant seasonal variation in the resulting carbon price modelled.

FIGURE 5-5: VARIATION IN MODELLED WEEKDAY CARBON PRICES FOR SP15 RELATIVE TO RETAIL TARIFF ENERGY CHARGES



5.3 SIMULATING IDEAL DISPATCH: RESULTS

The results of our RESTORE optimized dispatch modeling are presented in this section. We first discuss the results broadly, comparing dispatch, battery capacity factors and total impacts across each of the three dispatch approaches (customer bills, system costs and carbon, respectively). Subsequent sections delve into more detail on the results from each dispatch approach.

Some results on the emission, utility cost and bill savings impacts have been normalized by rebated capacity for comparison across all AES projects. As described in Section 5.1, many projects received their upfront payment mid-way through 2018, particularly among residential customers (only 17 residential customers in the sample began normal operations prior to 1/1/2018). Given the seasonal variation in system marginal emissions, system costs and bill savings potential, we present two sets of results ensuring fair comparisons can be made between projects that began normal operations or received upfront payments mid-way through 2018; 1) Annual results per rebated capacity for nonresidential customers that started normal operations prior to 1/1/2018 and 2) results for Q4 of 2018 that include both residential and nonresidential customers that started normal operations prior to 10/1/2018. However, all estimates for population level impacts include all customers in the modelling sample and account for customers that were offline during 2018.

5.3.1 Timing of Simulated Optimal Dispatch

Optimal storage dispatch is expected to vary depending on the dispatch approach being modeled. Below we use 12-month x 24-hour heat maps to illustrate simulated optimal AES net charging and discharging, averaged across the 272 nonresidential and 169 residential projects in the modelling sample. Green hours indicate that the sample of AES projects was simulated to be, in aggregate, net discharging, and red indicates that the aggregated sample was simulated to be net charging. Note that the charge and discharge values shown are net of parasitic charges as these are accounted for in the battery state of charge (not shown).

If optimized to minimize customer bills in 2018, the AES projects in our sample would have dispatched as shown in Figure 5-6. Recall that this dispatch approach optimized the dispatch of each AES project to minimize the sum of the customer's energy charges and monthly demand charges, given the retail rate to which they were subject and their annual gross load profile. An optimization of AES projects' dispatch using this dispatch approach shows diffused charging and discharging, and the overall kW magnitude of charging and discharging is relatively low. The periods of charging correspond broadly with utility-defined off-peak hours, and the periods of discharging correspond with on-peak hours, indicating that optimal AES dispatch from the customer perspective involves time-of-use (TOU) period rate arbitrage.

The nonresidential customers show more diffuse dispatch across the day during winter months but have quite distinct seasonal changes compared to residential customers. The nonresidential customers are on a more diverse range of tariffs and all of these include demand charges – both of these factors would tend to make the dispatch behavior more homogenous throughout the day. During the summer, the demand charges are significantly higher, while TOU tariffs also tend to have larger peak differentials for nonresidential customers. These factors are likely driving the high discharging seen during the summer period in the nonresidential figure.

FIGURE 5-6: OPTIMIZED AVERAGE WEEKDAY NET KW DISCHARGE (CHARGE) PER REBATED KW - CUSTOMER BILL DISPATCH FOR NONRESIDENTIAL (N=272) AND RESIDENTIAL (N=169) CUSTOMERS

Nonresidential Customers - Bill Dispatch Approach

Hour Beginning \ Month	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.044	-0.052	-0.051	-0.051	-0.067	-0.150	-0.147	-0.176	-0.156	-0.124	-0.067	-0.066
1	-0.027	-0.032	-0.037	-0.036	-0.048	-0.092	-0.079	-0.088	-0.085	-0.076	-0.046	-0.050
2	-0.027	-0.026	-0.032	-0.032	-0.046	-0.070	-0.060	-0.070	-0.067	-0.060	-0.051	-0.051
3	-0.039	-0.038	-0.042	-0.040	-0.054	-0.072	-0.064	-0.080	-0.077	-0.075	-0.071	-0.075
4	-0.063	-0.061	-0.051	-0.043	-0.065	-0.102	-0.084	-0.117	-0.110	-0.112	-0.103	-0.101
5	-0.099	-0.093	-0.047	-0.037	-0.090	-0.151	-0.134	-0.180	-0.150	-0.148	-0.142	-0.144
6	-0.028	-0.022	-0.012	-0.016	-0.042	-0.088	-0.086	-0.098	-0.076	-0.058	-0.047	-0.046
7	-0.069	-0.075	-0.076	-0.080	-0.104	-0.176	-0.172	-0.191	-0.150	-0.134	-0.110	-0.088
8	0.094	0.081	0.089	0.086	0.058	-0.001	0.009	0.004	0.003	0.100	0.164	0.166
9	0.011	0.004	0.015	0.021	0.024	0.000	0.010	0.006	0.003	0.036	0.037	0.042
10	0.004	0.004	-0.005	0.000	0.017	-0.003	0.008	0.003	0.000	0.030	0.029	0.034
11	0.002	0.003	-0.002	0.000	0.007	-0.014	-0.001	-0.010	-0.010	0.031	0.025	0.027
12	0.005	0.006	-0.005	-0.007	0.104	0.262	0.248	0.284	0.249	0.136	0.024	0.024
13	-0.001	0.001	-0.030	-0.041	0.022	0.080	0.069	0.090	0.071	0.047	0.015	0.017
14	0.003	0.002	0.006	0.003	0.013	0.065	0.053	0.072	0.059	0.033	0.019	0.015
15	-0.002	-0.002	-0.001	-0.003	0.007	0.048	0.036	0.052	0.042	0.017	0.013	0.008
16	0.054	0.046	0.050	0.054	0.073	0.131	0.118	0.149	0.121	0.100	0.079	0.063
17	0.036	0.031	0.025	0.020	0.100	0.263	0.237	0.274	0.244	0.132	0.053	0.052
18	0.024	0.023	0.025	0.026	0.015	-0.007	-0.009	-0.013	0.005	0.030	0.028	0.028
19	0.015	0.016	0.019	0.025	0.018	0.009	0.003	-0.004	0.001	0.015	0.021	0.023
20	0.043	0.041	0.048	0.040	0.037	0.060	0.062	0.059	0.056	0.089	0.065	0.064
21	-0.028	-0.024	-0.027	-0.022	-0.091	-0.087	-0.084	-0.100	-0.080	-0.114	-0.061	-0.062
22	-0.012	-0.011	-0.013	-0.013	-0.043	-0.045	-0.045	-0.050	-0.047	-0.057	-0.031	-0.030
23	-0.013	-0.014	-0.015	-0.017	-0.032	-0.123	-0.126	-0.155	-0.133	-0.043	-0.031	-0.029

Residential Customers - Bill Dispatch Approach

Hour Beginning \ Month	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.013	-0.008	-0.008	-0.007	-0.011	-0.112	-0.116	-0.119	-0.109	-0.126	-0.016	-0.006
1	-0.001	0.000	0.000	-0.001	-0.001	-0.013	-0.013	-0.014	-0.012	-0.013	-0.007	-0.001
2	-0.004	-0.003	-0.002	-0.003	-0.002	-0.010	-0.013	-0.011	-0.010	-0.013	-0.012	-0.002
3	-0.009	-0.009	-0.012	-0.013	-0.012	-0.055	-0.054	-0.060	-0.050	-0.057	-0.032	-0.011
4	-0.048	-0.046	-0.048	-0.052	-0.049	-0.101	-0.098	-0.108	-0.091	-0.104	-0.051	-0.043
5	-0.086	-0.089	-0.086	-0.098	-0.091	-0.194	-0.188	-0.205	-0.182	-0.198	-0.090	-0.082
6	-0.139	-0.135	-0.138	-0.141	-0.141	-0.137	-0.130	-0.144	-0.120	-0.135	-0.131	-0.127
7	-0.126	-0.122	-0.126	-0.126	-0.138	-0.131	-0.127	-0.138	-0.126	-0.135	-0.130	-0.120
8	0.015	0.002	-0.002	-0.003	-0.010	-0.015	-0.005	-0.017	-0.009	-0.011	0.007	0.003
9	0.003	-0.006	-0.008	-0.008	-0.042	-0.045	-0.034	-0.047	-0.037	-0.042	-0.003	-0.005
10	-0.019	-0.009	-0.013	-0.014	-0.017	-0.013	-0.008	-0.015	-0.013	-0.012	-0.010	-0.009
11	-0.042	-0.036	-0.037	-0.038	-0.032	-0.040	-0.027	-0.045	-0.039	-0.039	-0.037	-0.036
12	0.017	0.027	0.020	0.018	0.028	0.011	-0.001	0.012	0.004	0.026	0.021	0.025
13	-0.019	-0.002	-0.042	-0.041	0.033	0.014	-0.005	0.014	0.006	0.028	-0.010	-0.004
14	0.131	0.140	0.150	0.150	0.166	0.128	0.118	0.133	0.116	0.153	0.128	0.132
15	0.126	0.118	0.117	0.119	0.133	0.155	0.142	0.164	0.143	0.134	0.124	0.117
16	0.057	0.051	0.092	0.089	0.079	0.196	0.192	0.203	0.177	0.169	0.056	0.044
17	0.056	0.054	0.062	0.053	0.042	0.094	0.097	0.103	0.095	0.102	0.056	0.055
18	-0.027	-0.031	-0.037	-0.037	0.003	0.031	0.036	0.033	0.035	0.058	-0.026	-0.029
19	0.097	0.102	0.112	0.109	0.108	0.179	0.168	0.185	0.157	0.115	0.097	0.097
20	0.075	0.076	0.091	0.078	0.073	0.117	0.113	0.113	0.106	0.185	0.074	0.072
21	0.010	0.005	0.006	0.000	-0.036	-0.053	-0.046	-0.069	-0.042	-0.032	0.010	0.003
22	-0.132	-0.127	-0.121	-0.125	-0.135	-0.130	-0.131	-0.122	-0.123	-0.136	-0.132	-0.122
23	-0.098	-0.097	-0.100	-0.096	-0.111	-0.101	-0.099	-0.098	-0.090	-0.101	-0.097	-0.098

Minimum	-0.70	-0.19	0.00	0.34	0.73	Maximum

Shading represents maximum hourly net discharge/charge (kW/kW rebated capacity)

The net discharge/charge heatmap under the carbon dispatch approach is shown below in Figure 5-7. The pattern is similar to that of where customers generally charge during the night and discharge during the afternoon to early evening hours. As described in Section 5.2, the carbon dispatch signal combines the customers tariff with an hourly carbon price (Figure 5-4). In many hours, the carbon price is small compared to the customer tariff. Under TOU rates, the carbon price is rarely large enough to overcome the peak to off-peak price differential resulting in dispatch behavior changing within TOU blocks, but seldom shifting charging or discharging between TOU blocks. Consequently the differences between Figure 5-6 and Figure 5-7 are subtle. However, as discussed later in the section, the impact on emissions and system costs can be significant.

The differences between the bill savings approach and the carbon approach is less pronounced for the nonresidential customers which is likely due to demand charge minimization still being a more dominant dispatch signal than the carbon price.

FIGURE 5-7: OPTIMIZED AVERAGE WEEKDAY NET KW DISCHARGE (CHARGE) PER REBATED KW – CARBON DISPATCH FOR NONRESIDENTIAL (N=272) AND RESIDENTIAL (N=169) CUSTOMERS

Nonresidential Customers - Carbon Dispatch Approach

Hour Beginning	Month 1	2	3	4	5	6	7	8	9	10	11	12
0	-0.061	-0.059	-0.036	-0.066	-0.095	-0.120	-0.132	-0.160	-0.160	-0.107	-0.107	-0.066
1	-0.056	-0.066	-0.046	-0.062	-0.117	-0.152	-0.161	-0.168	-0.153	-0.116	-0.093	-0.070
2	-0.065	-0.089	-0.048	-0.050	-0.107	-0.160	-0.138	-0.218	-0.114	-0.106	-0.117	-0.089
3	-0.062	-0.068	-0.042	-0.044	-0.049	-0.077	-0.083	-0.106	-0.079	-0.103	-0.071	-0.097
4	-0.059	-0.040	-0.053	-0.024	-0.015	-0.064	-0.083	-0.085	-0.091	-0.102	-0.057	-0.067
5	-0.034	-0.016	-0.010	0.005	-0.016	-0.062	-0.052	-0.055	-0.058	-0.022	-0.040	-0.064
6	0.000	0.011	0.017	-0.003	-0.036	-0.103	-0.064	-0.063	-0.022	0.023	0.006	0.005
7	0.004	0.003	-0.028	-0.045	-0.061	-0.113	-0.119	-0.129	-0.106	-0.040	0.000	0.018
8	0.013	0.013	0.028	0.009	0.006	-0.014	-0.021	-0.008	-0.019	-0.005	0.021	0.070
9	-0.014	-0.006	0.008	0.009	0.009	-0.012	-0.007	-0.003	-0.010	-0.014	0.005	0.013
10	-0.005	-0.009	-0.028	-0.024	0.004	-0.003	0.008	-0.005	-0.006	-0.002	-0.009	0.006
11	-0.004	-0.027	-0.028	-0.014	0.002	-0.006	0.002	-0.003	-0.007	0.014	0.007	0.006
12	-0.007	-0.012	-0.023	-0.019	0.061	0.111	0.087	0.111	0.073	0.050	0.015	0.005
13	0.012	-0.016	-0.041	-0.034	0.010	0.085	0.126	0.090	0.066	0.047	0.015	0.020
14	0.007	-0.022	-0.013	-0.010	0.014	0.081	0.066	0.130	0.070	0.030	0.033	-0.002
15	-0.006	-0.015	-0.021	-0.018	0.009	0.062	0.067	0.099	0.059	0.039	0.023	0.005
16	0.040	0.024	0.034	0.034	0.073	0.182	0.148	0.184	0.230	0.175	0.057	0.045
17	0.071	0.038	0.043	0.041	0.128	0.304	0.295	0.308	0.313	0.170	0.090	0.067
18	0.053	0.113	0.072	0.117	0.086	0.051	0.056	0.041	0.032	0.067	0.061	0.072
19	0.067	0.077	0.045	0.084	0.082	0.041	0.035	0.035	0.021	0.039	0.081	0.084
20	0.081	0.077	0.093	0.068	0.027	0.011	0.000	0.005	0.000	0.058	0.127	0.062
21	-0.008	-0.006	-0.007	-0.009	-0.029	-0.047	-0.036	-0.058	-0.052	-0.058	-0.034	-0.042
22	-0.019	-0.012	-0.022	-0.028	-0.061	-0.058	-0.046	-0.049	-0.043	-0.077	-0.030	-0.025
23	-0.040	-0.026	-0.020	-0.024	-0.051	-0.099	-0.087	-0.130	-0.101	-0.053	-0.061	-0.058

Residential Customers - Carbon Dispatch Approach

Hour Beginning	Month 1	2	3	4	5	6	7	8	9	10	11	12
0	-0.084	-0.072	-0.049	-0.100	-0.120	-0.124	-0.140	-0.136	-0.166	-0.161	-0.131	-0.044
1	-0.073	-0.089	-0.070	-0.098	-0.167	-0.168	-0.207	-0.153	-0.158	-0.190	-0.113	-0.058
2	-0.093	-0.141	-0.070	-0.074	-0.137	-0.176	-0.169	-0.263	-0.117	-0.161	-0.112	-0.079
3	-0.084	-0.101	-0.063	-0.052	-0.026	-0.056	-0.101	-0.100	-0.056	-0.138	-0.063	-0.090
4	-0.093	-0.054	-0.089	-0.042	0.024	-0.032	-0.110	-0.082	-0.083	-0.145	-0.039	-0.056
5	-0.053	-0.011	-0.029	0.002	-0.003	-0.052	-0.062	-0.058	-0.071	-0.023	-0.033	-0.065
6	-0.010	0.007	-0.020	-0.063	-0.111	-0.198	-0.094	-0.098	-0.021	0.019	-0.011	-0.021
7	-0.021	-0.025	-0.060	-0.108	-0.110	-0.130	-0.142	-0.158	-0.112	-0.088	-0.011	-0.011
8	-0.003	-0.013	-0.015	-0.021	-0.022	-0.054	-0.049	-0.042	-0.112	-0.042	-0.026	0.014
9	-0.055	-0.026	-0.018	-0.019	-0.019	-0.026	-0.025	-0.014	-0.051	-0.058	-0.030	-0.009
10	-0.016	-0.018	-0.055	-0.053	-0.027	-0.003	0.003	-0.014	-0.019	-0.032	-0.061	-0.025
11	-0.038	-0.059	-0.098	-0.033	-0.012	-0.005	0.010	-0.001	-0.017	-0.024	-0.035	-0.037
12	-0.026	-0.013	-0.045	-0.040	0.017	0.001	-0.021	0.005	-0.007	0.004	-0.019	-0.019
13	0.004	-0.038	-0.088	-0.052	-0.011	0.009	0.013	0.012	0.009	0.005	-0.012	-0.012
14	0.008	-0.061	-0.035	-0.033	0.030	0.016	0.035	0.089	0.030	0.024	0.032	-0.010
15	0.031	0.004	-0.019	-0.008	0.019	0.028	0.039	0.091	0.041	0.079	0.067	0.014
16	0.095	0.069	0.095	0.086	0.064	0.103	0.138	0.158	0.215	0.278	0.070	0.062
17	0.175	0.142	0.192	0.144	0.177	0.236	0.300	0.277	0.334	0.259	0.168	0.139
18	0.153	0.254	0.229	0.276	0.274	0.386	0.400	0.316	0.253	0.163	0.131	0.138
19	0.203	0.236	0.162	0.217	0.247	0.315	0.223	0.270	0.165	0.200	0.197	0.208
20	0.103	0.089	0.114	0.081	0.047	0.050	0.014	0.052	0.005	0.141	0.112	0.072
21	0.009	0.010	0.009	0.005	-0.006	-0.027	-0.002	-0.053	-0.032	-0.014	-0.003	0.000
22	-0.039	-0.045	-0.066	-0.063	-0.071	-0.121	-0.086	-0.082	-0.086	-0.083	-0.045	-0.047
23	-0.129	-0.123	-0.078	-0.059	-0.122	-0.114	-0.087	-0.138	-0.088	-0.113	-0.102	-0.144

Minimum	-0.70	-0.19	0.00	0.34	0.73	Maximum

Ideal dispatch using the System Cost Dispatch is shown in Figure 5-8. If nonresidential AES projects were dispatched with perfect information in 2018 to minimize system costs, then they would have tended to charge during the middle of the night to early morning and the middle of the day, when both system net load and energy costs are lower. Discharge would have occurred when the utilities' marginal costs are highest (between 5 and 7 am) as customer load starts to increase, but before solar production has begun, and in the evening (4 – 7 pm), when the utilities' marginal costs are highest.

The depth of average discharge and charge is much higher for the system cost approach, which is primarily driven by the volatility of the system cost price signal. This is discussed further in the next section. Both the nonresidential and residential customers show very similar dispatch patterns under this approach which is expected given the avoided cost streams are only dependent on utility and climate zone rather than customer type. The residential dispatch pattern is slightly more pronounced which is likely due to the higher average roundtrip efficiency for residential AES projects in the sample (82.3 percent) versus nonresidential (71.1 percent).

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FIGURE 5-8: OPTIMIZED AVERAGE WEEKDAY NET KW DISCHARGE (CHARGE), AGGREGATED KW ACROSS SAMPLE – SYSTEM COST DISPATCH FOR NONRESIDENTIAL (N=272) AND RESIDENTIAL (N=169) CUSTOMERS

Nonresidential Customers - System Dispatch Approach

Month

Hour Beginning	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.139	-0.162	-0.175	-0.203	-0.290	-0.114	-0.186	-0.220	-0.080	-0.133	-0.075	-0.063
1	-0.304	-0.193	-0.375	-0.524	-0.579	-0.322	-0.298	-0.266	-0.334	-0.495	-0.252	-0.222
2	-0.438	-0.503	-0.508	-0.586	-0.570	-0.396	-0.502	-0.499	-0.347	-0.510	-0.523	-0.386
3	-0.456	-0.467	-0.154	-0.059	-0.061	-0.030	-0.282	-0.206	-0.046	-0.080	-0.353	-0.289
4	-0.072	-0.043	0.019	0.222	0.345	0.176	-0.029	-0.023	0.013	0.038	-0.027	-0.034
5	0.017	0.066	0.342	0.612	0.646	0.456	0.095	0.259	0.310	0.375	0.201	0.019
6	0.350	0.582	0.561	0.286	0.182	0.099	-0.023	0.079	0.124	0.475	0.531	0.317
7	0.484	0.454	0.152	-0.063	-0.250	-0.636	-0.236	-0.395	-0.092	-0.018	0.173	0.349
8	0.026	0.036	0.016	-0.211	-0.365	-0.509	-0.166	-0.327	-0.496	-0.134	-0.089	0.026
9	-0.099	-0.036	-0.126	-0.190	-0.354	-0.320	-0.071	-0.113	-0.411	-0.414	-0.309	-0.041
10	-0.128	-0.217	-0.286	-0.323	-0.206	-0.098	-0.026	-0.064	-0.176	-0.477	-0.335	-0.084
11	-0.234	-0.245	-0.435	-0.405	-0.261	-0.164	-0.012	-0.056	-0.064	-0.328	-0.267	-0.205
12	-0.490	-0.510	-0.441	-0.239	-0.206	-0.078	-0.035	-0.004	-0.012	-0.106	-0.380	-0.508
13	-0.334	-0.449	-0.388	-0.288	-0.185	-0.078	-0.012	0.017	-0.003	-0.081	-0.157	-0.371
14	-0.157	-0.348	-0.209	-0.214	-0.245	-0.074	0.021	0.033	0.003	-0.068	-0.053	-0.156
15	-0.012	-0.068	-0.149	-0.132	-0.109	-0.077	0.052	0.064	0.038	-0.007	0.022	0.004
16	0.048	0.017	0.025	-0.038	-0.064	0.052	0.113	0.099	0.070	0.119	0.146	0.049
17	0.527	0.218	0.130	0.076	0.069	0.084	0.369	0.466	0.413	0.615	0.635	0.525
18	0.530	0.642	0.677	0.595	0.380	0.632	0.558	0.545	0.536	0.490	0.359	0.383
19	0.099	0.249	0.404	0.541	0.708	0.472	0.154	0.128	0.104	0.104	0.075	0.104
20	0.085	0.120	0.112	0.085	0.202	0.085	0.024	0.033	0.050	0.061	0.057	0.065
21	0.043	0.057	0.056	0.055	0.066	0.042	-0.005	0.004	0.009	0.029	0.029	0.030
22	0.008	0.005	-0.033	-0.007	0.029	-0.003	-0.043	-0.007	-0.056	-0.051	0.010	0.004
23	-0.033	-0.063	-0.140	-0.047	-0.030	0.005	-0.066	-0.034	-0.039	-0.045	-0.050	-0.079

Residential Customers - System Dispatch Approach

Month

Hour Beginning	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.211	-0.237	-0.264	-0.301	-0.392	-0.184	-0.280	-0.335	-0.136	-0.228	-0.125	-0.104
1	-0.432	-0.279	-0.490	-0.604	-0.639	-0.506	-0.392	-0.401	-0.492	-0.645	-0.380	-0.338
2	-0.556	-0.592	-0.615	-0.650	-0.612	-0.598	-0.607	-0.648	-0.558	-0.640	-0.678	-0.539
3	-0.562	-0.534	-0.221	-0.057	-0.069	-0.075	-0.309	-0.258	-0.063	-0.146	-0.465	-0.417
4	-0.115	-0.063	0.043	0.353	0.516	0.355	0.030	0.005	0.052	0.087	-0.022	-0.050
5	0.065	0.180	0.493	0.669	0.704	0.648	0.217	0.546	0.572	0.556	0.360	0.054
6	0.543	0.689	0.683	0.439	0.315	0.203	0.016	0.237	0.340	0.640	0.692	0.508
7	0.689	0.628	0.289	-0.046	-0.267	-0.696	-0.312	-0.525	-0.162	-0.002	0.353	0.559
8	0.103	0.098	0.052	-0.217	-0.367	-0.553	-0.176	-0.437	-0.591	-0.204	-0.093	0.100
9	-0.104	-0.017	-0.139	-0.200	-0.359	-0.337	-0.062	-0.145	-0.509	-0.429	-0.405	-0.025
10	-0.189	-0.248	-0.301	-0.349	-0.229	-0.200	-0.019	-0.080	-0.242	-0.513	-0.405	-0.103
11	-0.354	-0.319	-0.473	-0.418	-0.292	-0.163	0.005	-0.043	-0.053	-0.354	-0.363	-0.291
12	-0.612	-0.575	-0.479	-0.242	-0.175	-0.024	-0.032	0.000	0.000	-0.112	-0.453	-0.601
13	-0.393	-0.487	-0.385	-0.289	-0.136	0.005	-0.032	0.003	0.000	-0.032	-0.160	-0.457
14	-0.171	-0.340	-0.170	-0.144	-0.219	-0.017	-0.003	0.014	0.000	-0.023	-0.022	-0.183
15	-0.001	-0.025	-0.068	-0.054	-0.043	0.000	0.029	0.046	0.000	0.001	0.000	0.000
16	0.007	0.000	0.009	0.000	-0.032	0.011	0.184	0.154	0.139	0.209	0.255	0.044
17	0.651	0.304	0.220	0.153	0.097	0.175	0.508	0.591	0.539	0.703	0.726	0.621
18	0.679	0.698	0.701	0.643	0.515	0.671	0.647	0.672	0.637	0.642	0.545	0.535
19	0.232	0.398	0.564	0.647	0.733	0.615	0.263	0.237	0.220	0.212	0.148	0.227
20	0.161	0.231	0.203	0.196	0.343	0.170	0.005	0.021	0.016	0.027	0.026	0.092
21	0.000	0.020	0.022	0.007	0.053	0.000	-0.010	0.000	0.000	0.004	0.000	-0.007
22	-0.001	-0.022	-0.070	-0.063	-0.019	-0.039	-0.055	-0.032	-0.098	-0.098	0.000	-0.010
23	-0.067	-0.129	-0.216	-0.088	-0.089	-0.015	-0.055	-0.012	-0.058	-0.087	-0.092	-0.144

Minimum	-0.70	-0.19	0.00	0.34	0.73	Maximum

5.3.2 Capacity Factors and Roundtrip Efficiencies Under Optimized AES Dispatch

How much the AES projects in the sample would have optimally been utilized in 2018 under each of the three dispatch approaches was examined by calculating their theoretical SGIP capacity factor (CF). In this exercise, the SGIP CF is calculated as the ratio of optimal discharge to maximum possible discharge over 60 percent of hours for the SGIP *rebated* capacity as defined by the equation in Section 4. Hours were adjusted according to the customers start date of normal operations. This provides a measure of how much a project is utilized under optimal dispatch relative to its maximum potential use. Each marker in Figure 5-9 and Figure 5-10 represents the CF for an individual AES project in our sample. The chart is sorted by CF to better understand the distribution of values across all projects.

FIGURE 5-9: AES PROJECT SGIP CAPACITY FACTORS ASSUMING OPTIMAL DISPATCH, BY DISPATCH APPROACH, FOR NONRESIDENTIAL CUSTOMERS (N=272)

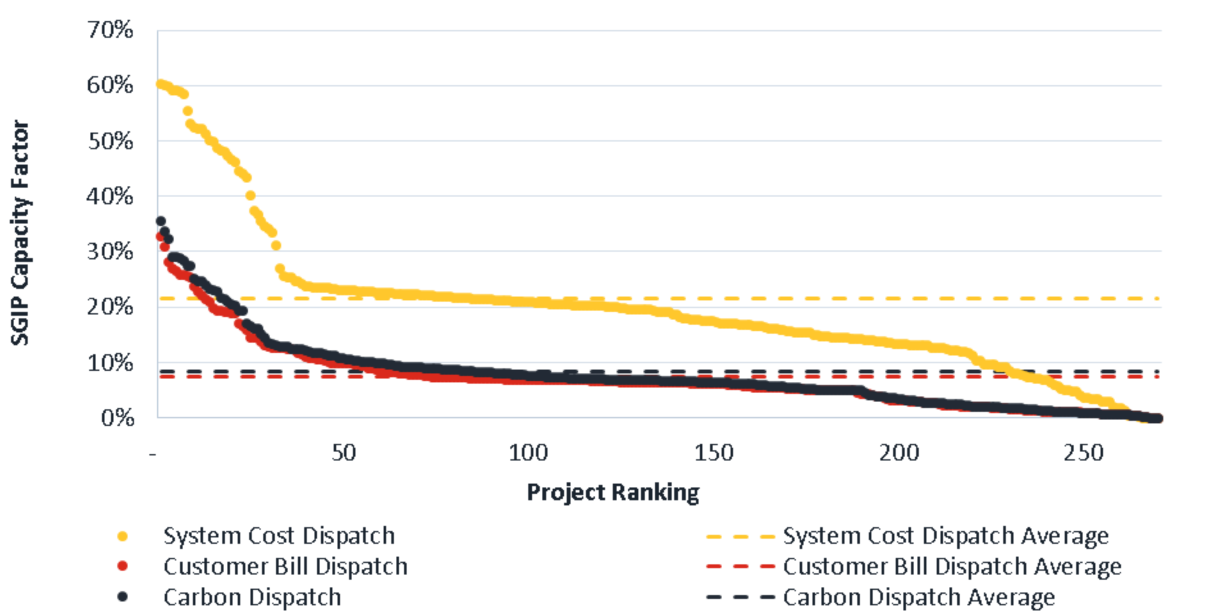
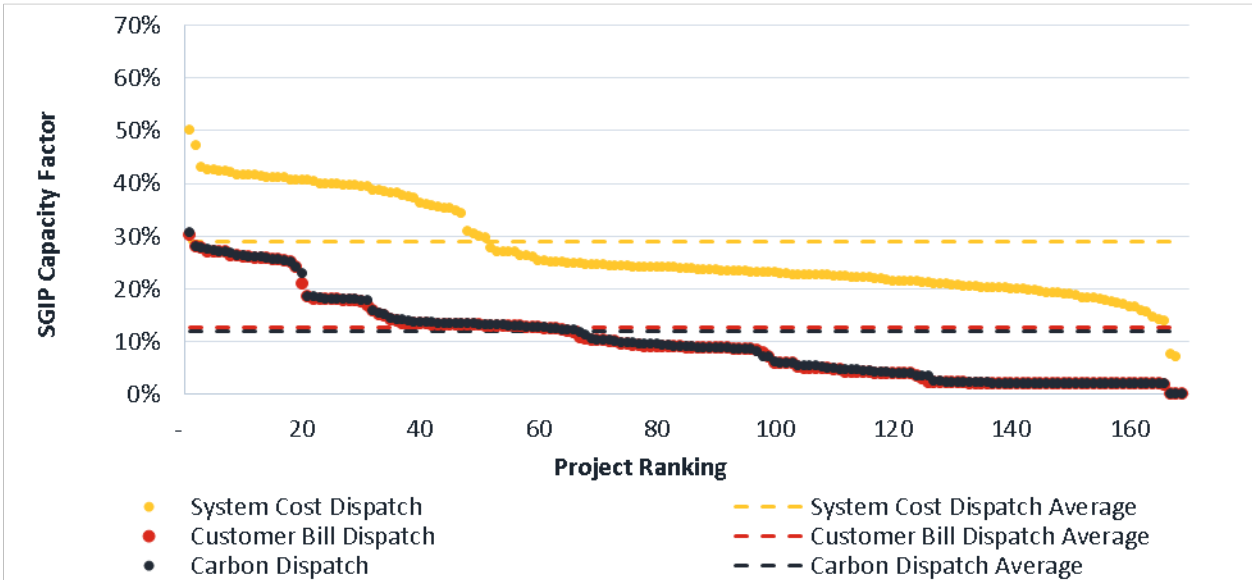


FIGURE 5-10: AES PROJECT SGIP CAPACITY FACTORS ASSUMING OPTIMAL DISPATCH, BY DISPATCH APPROACH, FOR RESIDENTIAL CUSTOMERS (N=169)



There are several points to note. Higher volatility in the avoided cost streams lead to greater opportunities for arbitrage. Marginal costs fluctuate on an hourly basis, whereas TOU rates stay the same for multiple hours. Therefore, the simulated SGIP CF under the System Cost approach are generally highest, while CFs under the Customer Bill dispatch are generally the lowest. As described in Section 5.2, carbon dispatch combines both the utility electric rate and a carbon price signal. The fluctuation in the carbon price signal is relatively small compared to the peak to off-peak differential of electric utility rates. Therefore, there are only a few hours where the carbon price is sufficiently large to overcome RTE losses and incentivize additional battery cycles than under the customer bill approach. This results in a slight increase in capacity factor from the Customer Bill approach to the Carbon approach.

Note that 8 nonresidential and 3 residential projects under customer dispatch approach had a capacity factor of zero meaning it was not optimal for them to be utilized at all during 2018 (or from their date of normal operations). These customers all had low RTE's which were below the required limit to be eligible for the SGIP (66.5 percent for both nonresidential and residential customers) and therefore had no cycling constraint applied when modelled, as described in Section 5.2.

SGIP AES nonresidential projects dispatched to minimize system costs have a maximum SGIP CF of 60 percent while residential projects had a maximum of 50 percent. All the high capacity factor projects among both nonresidential and residential customers all had high RTEs > 85 percent, long durations (4 hours or greater) and began normal operations just before the summer period.

Energy storage RTE is an important consideration related to storage project utilization. Projects with higher RTEs are able to arbitrage across smaller price differentials because less of their discharge is going to battery losses. The higher average capacity factors for residential customers, compared to nonresidential customers, is primarily due to residential customers having a higher average RTE. To further illustrate the importance of RTE, Figure 5-11 and Figure 5-12 present the capacity factor results from system cost approach categorized by RTE. In general, projects with high RTEs (greater than 75 percent) have higher capacity factors than those with medium RTEs (greater than 45 percent but less than 75 percent), which in turn have higher capacity factors than low RTE (0 – 45 percent) projects. However, there are exceptions which indicate other factors, such as the storage duration and start date of normal operations, also influence capacity factor.

FIGURE 5-11: AES PROJECT SGIP CAPACITY FACTORS ASSUMING OPTIMAL DISPATCH, BY OBSERVED ROUND-TRIP EFFICIENCY (RTE) BIN FOR NONRESIDENTIAL CUSTOMERS – SYSTEM COST DISPATCH APPROACH (N=272)

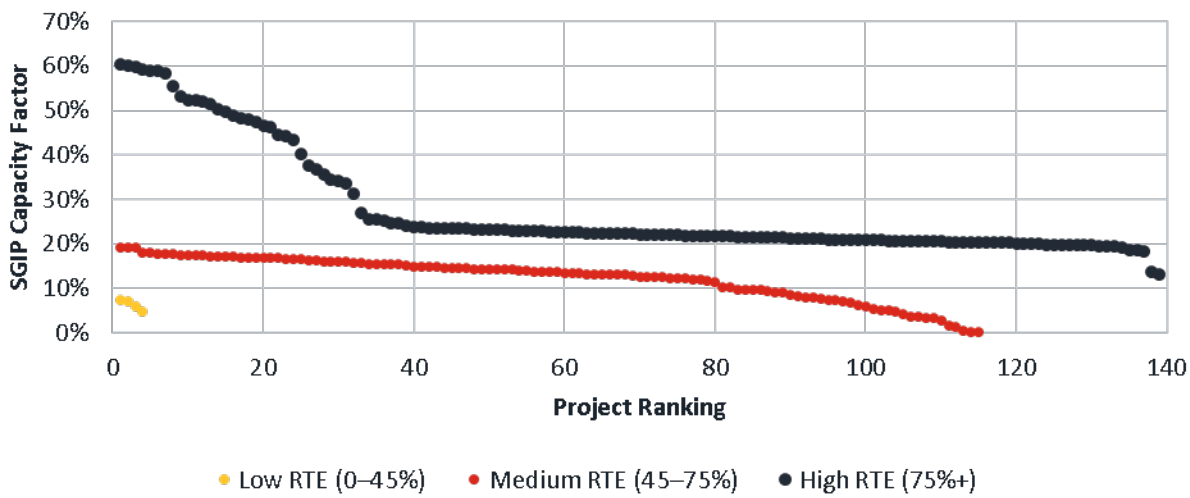
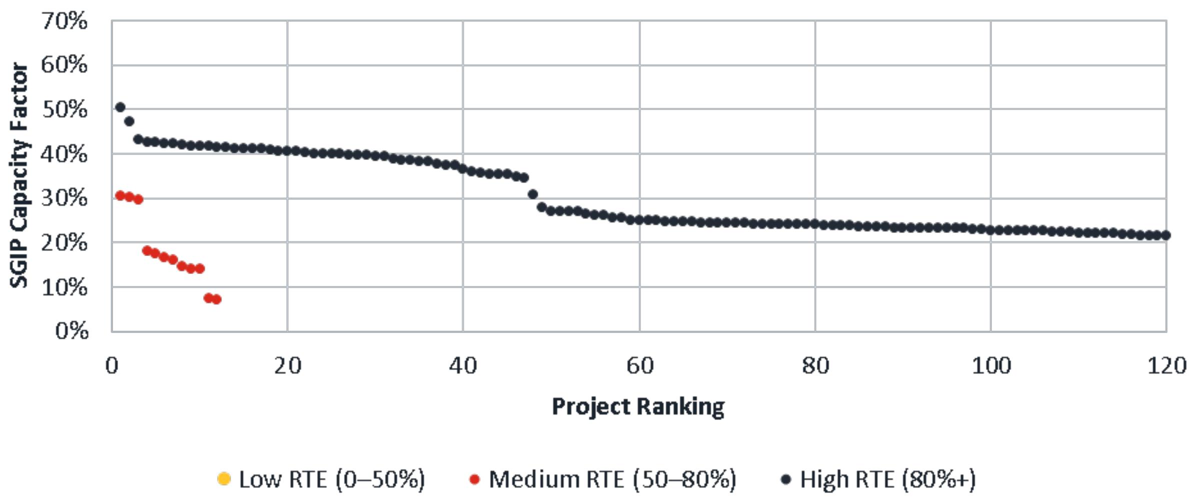


FIGURE 5-12: AES PROJECT SGIP CAPACITY FACTORS ASSUMING OPTIMAL DISPATCH, BY OBSERVED ROUND-TRIP EFFICIENCY (RTE) BIN FOR RESIDENTIAL CUSTOMERS – SYSTEM COST DISPATCH APPROACH (N=169)



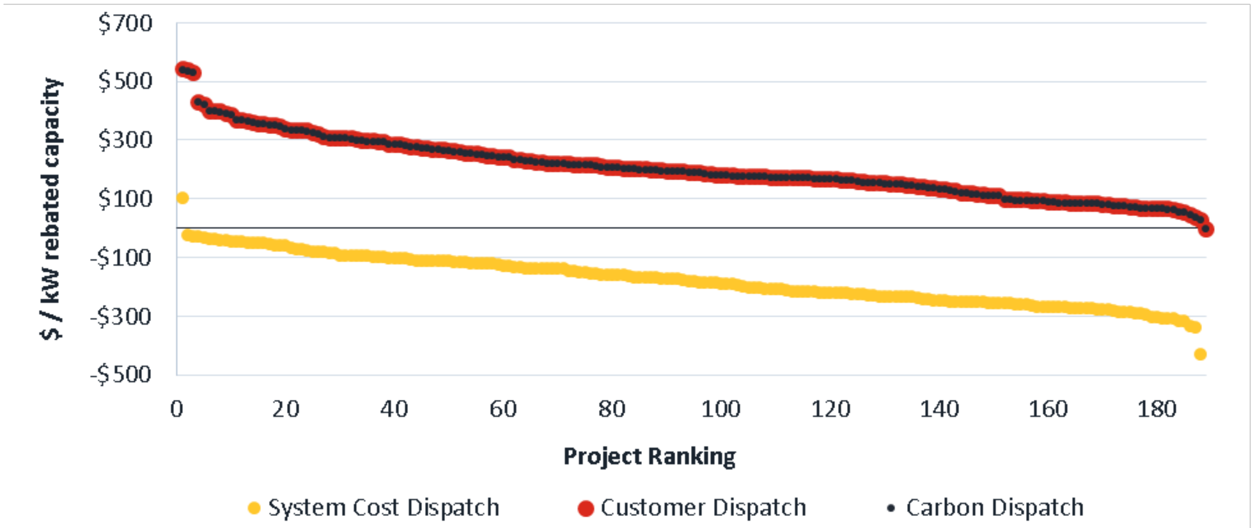
5.3.3 Potential Customer Bill Savings Achievable by AES Projects

We analyzed the customer bill savings that would have been generated by AES projects *if they were optimally dispatched according to each dispatch approach, with perfect foresight.* Recall that this analysis does not include bill savings from demand response programs that were not critical peak pricing tariffs.

Firstly, looking at the distribution of annual bill savings per rebated capacity for nonresidential AES projects that began normal operations prior to 1/1/2018, we find that if they had been dispatched to minimize customer bills, their bill *savings* per rebated kW could have been as high as $540.66 / kW in 2018 (Figure 5-13).

Notably, these nonresidential AES projects would have achieved very similar bill savings had they been dispatched under the carbon dispatch approach. However, optimizing AES dispatch to minimize system marginal costs would have led to a substantial *increase* in most customers' bills under 2018 rates, up to $480.13 / kW. This suggests that for nearly all nonresidential AES customers operating prior to 1/1/2018 there was significant misalignment between customer/societal and system incentives for storage dispatch in 2018.

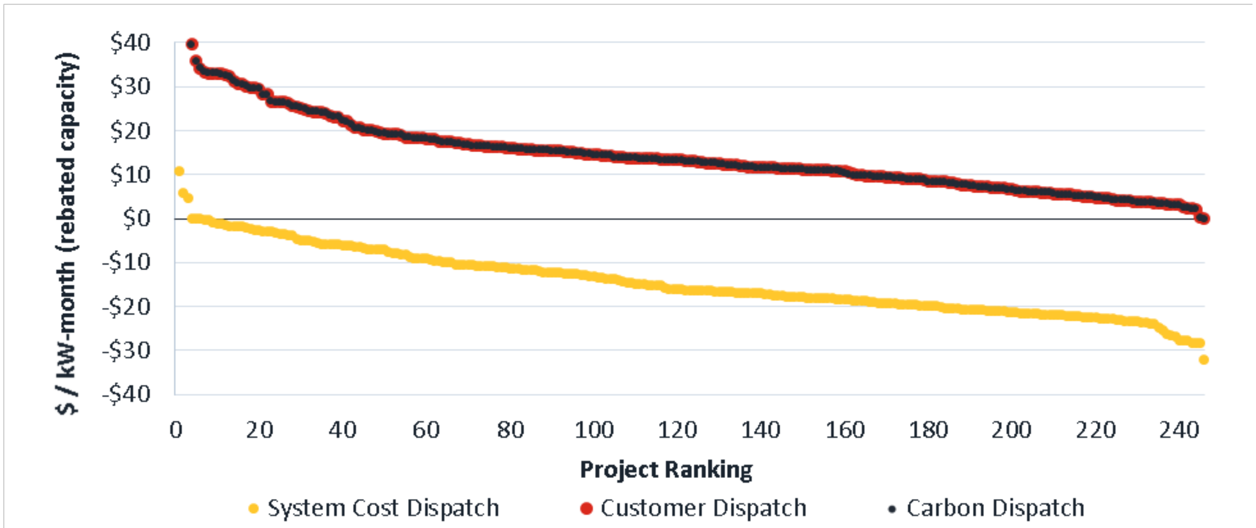
FIGURE 5-13: DISTRIBUTION OF ANNUAL ELECTRICITY BILL SAVINGS ATTRIBUTABLE TO AES PROJECTS UNDER OPTIMAL DISPATCH FOR NONRESIDENTIAL CUSTOMERS ONLINE BEFORE JANUARY 1ST 2018, BY DISPATCH APPROACH, $ PER KW OF REBATED CAPACITY (N=189)



As described in Section 5.3, for the bill savings, utility avoided costs and emissions impact results that are normalized per rebated capacity, we also analyze Q4 results to ensure fair comparison for projects beginning normal operations mid-way through the year.

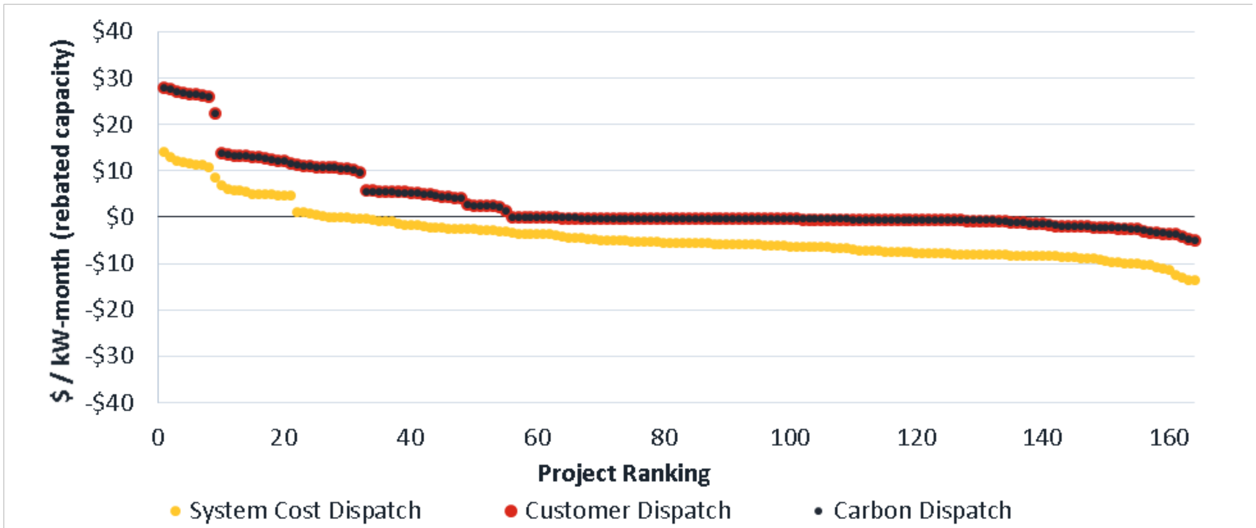
Looking at the monthly results for nonresidential customers during the Q4 period we see very similar magnitudes for costs/savings when annual and Q4 results are converted to the same units. This is somewhat surprising since most customer tariffs in the modelling sample had higher bill savings opportunities in the summer compared to winter, due to higher peak to off-peak differentials for TOU tariffs and higher summer demand charges. The overall trend between annual and Q4 results for nonresidential customers is similar with large differences between bill savings under system cost dispatch and the customer or carbon dispatch approaches as shown in Figure 5-14.

FIGURE 5-14: DISTRIBUTION OF ANNUAL ELECTRICITY BILL SAVINGS ATTRIBUTABLE TO AES PROJECTS UNDER OPTIMAL DISPATCH FOR NONRESIDENTIAL CUSTOMERS ONLINE BEFORE OCTOBER 1ST 2018, BY DISPATCH APPROACH, $ PER KW OF REBATED CAPACITY (N=246)



The potential bill savings achievable for residential customers in Q4 of 2018 is lower compared with those for nonresidential customers. Most nonresidential tariffs include demand charges unlike residential tariffs, which offer much greater bill savings potential for nonresidential AES projects. For residential AES projects, the bill savings under different dispatch approaches are much closer, indicating stronger alignment between incentives to minimize electric bills and to minimize system costs. This difference is also likely due to demand charges and will be explored later in this section when analyzing dispatch behavior during different TOU periods.

FIGURE 5-15: DISTRIBUTION OF ANNUAL ELECTRICITY BILL SAVINGS ATTRIBUTABLE TO AES PROJECTS UNDER OPTIMAL DISPATCH FOR RESIDENTIAL CUSTOMERS ONLINE BEFORE OCTOBER 1ST 2018, BY DISPATCH APPROACH, $ PER KW OF REBATED CAPACITY (N=164)



Note that for the residential Q4 results, some customers show negative bill savings in Q4. These customers are not on TOU rates, and in some cases have lower RTE's but are still required to meet the cycling constraint which is pro-rated for the Q4 period.

Scaling these sample results suggests that total potential savings to customers across the 539 nonresidential SGIP AES projects in the population would have been approximately $14.07 million in 2018, excluding bill savings from demand response programs, if these projects were optimally dispatched to minimize customer bills with perfect foresight (Figure 5-16). On average, this would have amounted to an annual bill savings of about approximately $26,100 per nonresidential SGIP storage project that was operating in 2018.

For the 90 percent of residential customers our modelling sample can represent, the results suggest that total potential savings have been approximately $847,000 in 2018, or $251 per residential SGIP storage project active in 2018. Recall that a majority of these projects were only operating for part of 2018 (Figure 5-17).

FIGURE 5-16: ESTIMATED 2018 BILL SAVINGS ATTRIBUTABLE TO THE POPULATION OF NONRESIDENTIAL AES PROJECTS IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH ($/REBATED CAPACITY), EXCLUDING DEMAND RESPONSE BENEFITS

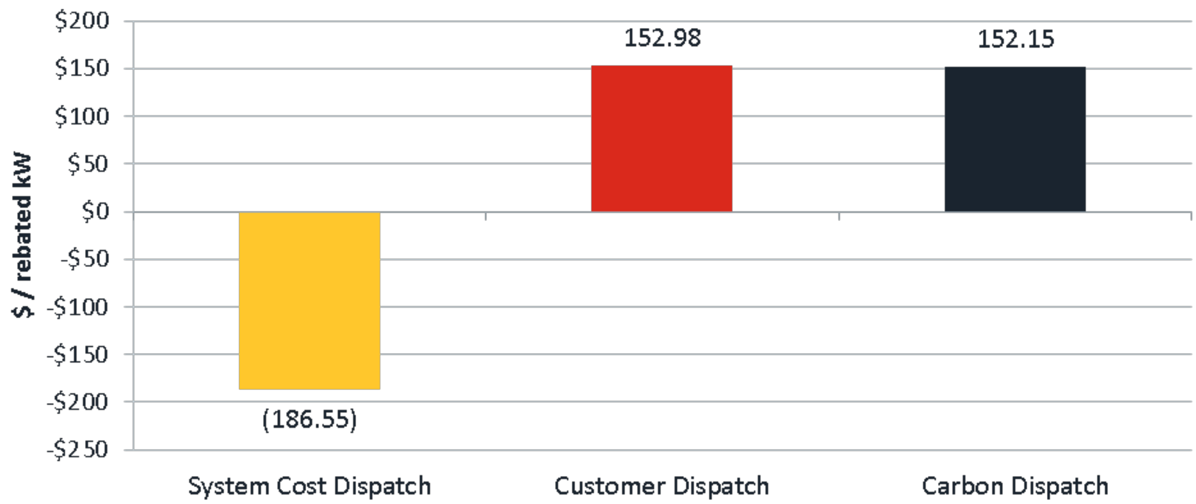
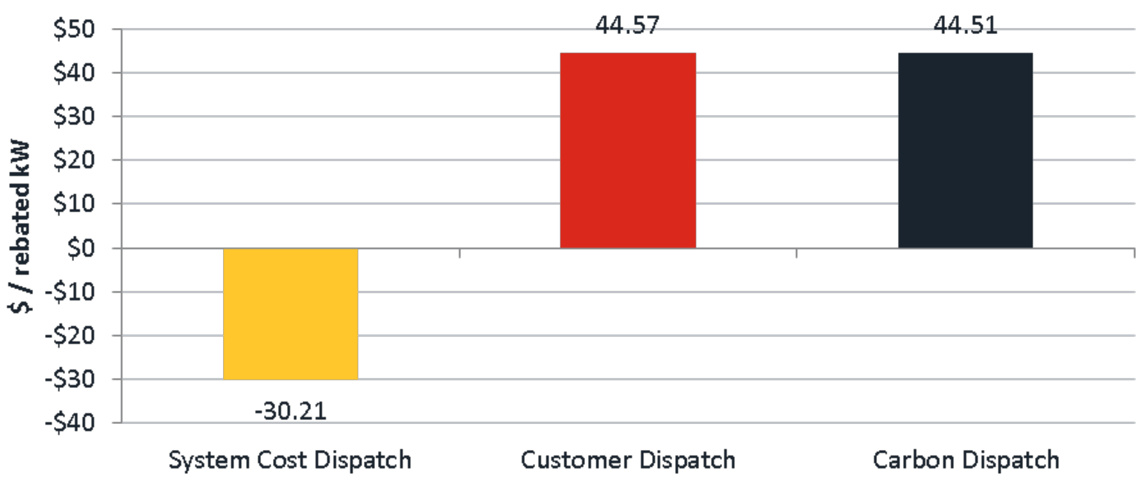
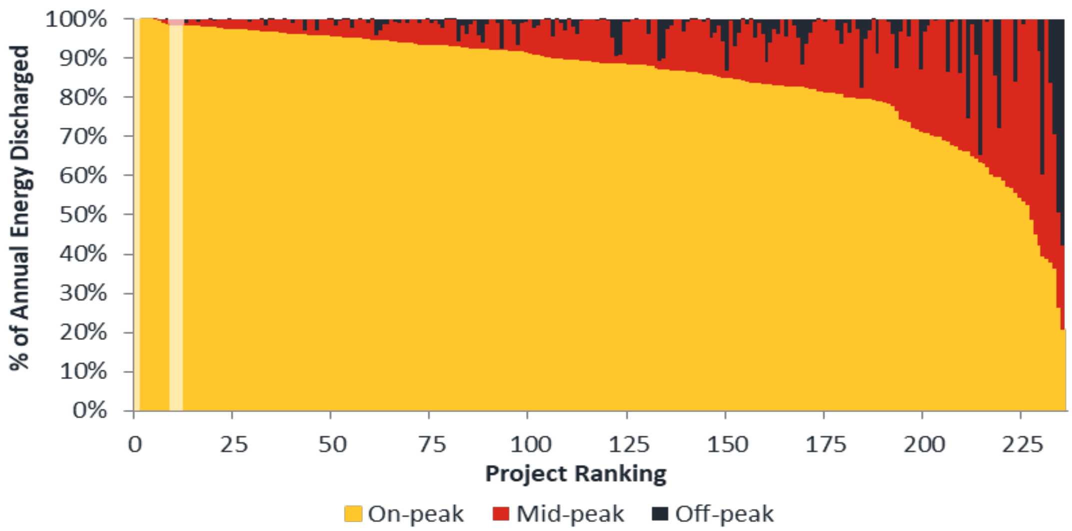


FIGURE 5-17: ESTIMATED 2018 BILL SAVINGS ATTRIBUTABLE TO THE POPULATION OF RESIDENTIAL AES PROJECTS IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH ($/REBATED CAPACITY), EXCLUDING DEMAND RESPONSE BENEFITS



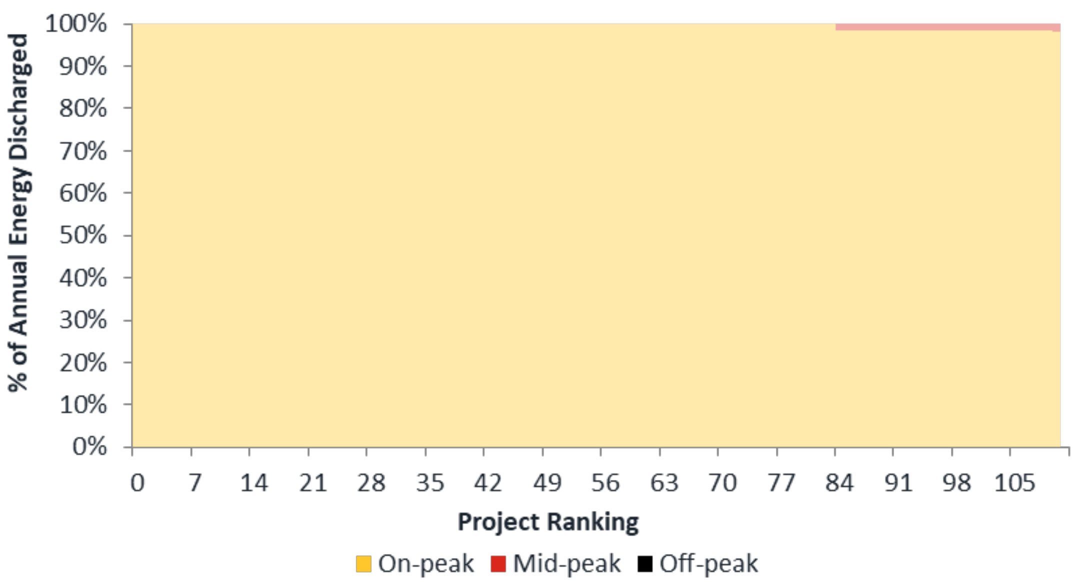
These savings would have come from a combination of demand charge minimization and TOU period rate arbitrage. Figure 5-18 displays the timing, by TOU period, of each storage project's discharged energy, in percentage terms, under optimized dispatch. The figure shows that the extent to which TOU rate arbitrage would be given priority is wide-ranging. While most customers devote the majority of their discharging to on-peak hours, none of the customers charged entirely on-peak. The average energy discharged on-peak is about 80 percent; while the average energy discharged at mid-peak is 16 percent, and 4 percent for off-peak hours.

FIGURE 5-18: SUMMER WEEKDAY STORAGE DISCHARGE BY TOU PERIOD, FOR NONRESIDENTIAL CUSTOMERS ON TOU TARIFFS, IF OPTIMALLY DISPATCHED TO MINIMIZE CUSTOMER BILL (N=236)



* Note the lighter shading indicates the customer has no demand charges

FIGURE 5-19: SUMMER WEEKDAY STORAGE DISCHARGE BY TOU PERIOD, FOR RESIDENTIAL CUSTOMERS ON TOU TARIFFS, IF OPTIMALLY DISPATCHED TO MINIMIZE CUSTOMER BILL (N=111)



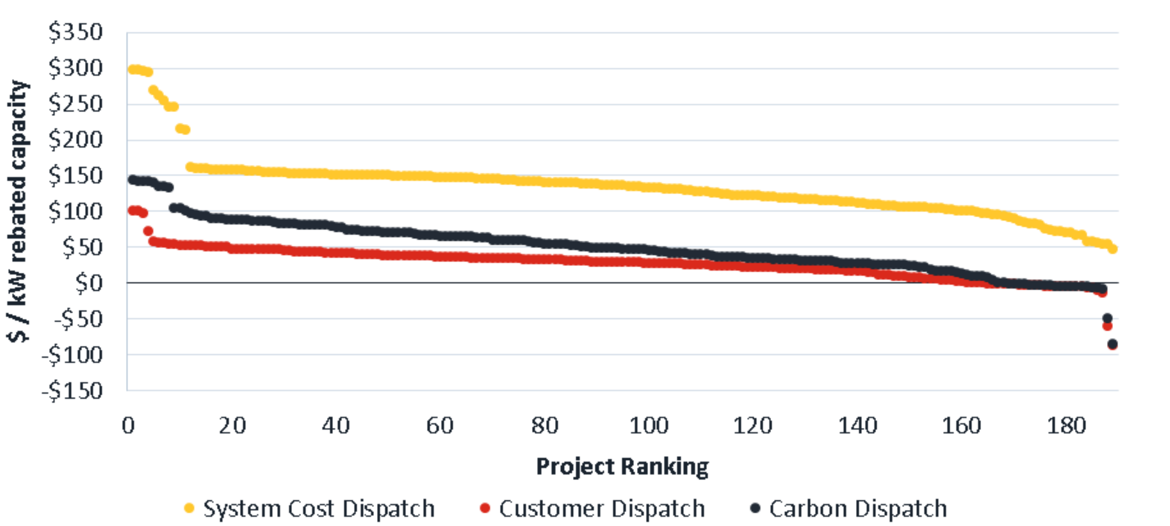
In this years' study, only summer weekdays were included in the calculation to ensure discharge on days without any TOU peak did not distort the results and for consistency with Section 4. As with the 2017 report, we find that nonresidential customers do not always discharge during TOU peak hours and that pairing TOU rates with demand charges can undermine the extent to which the timing of customers' load can be influenced. This year we were also able to include the equivalent results for residential customers which further emphasize this point. No residential tariffs in the modelling sample included demand charges and almost all residential customers therefore discharged 100 percent of their energy during peak hours under customer bill dispatch.

While demand charges may incentivize customers to reduce their peak demand, they will not necessarily do so in the hours in which a utility most needs a demand reduction. In fact, demand charges can incentivize customers to maintain low energy consumption in hours in which it would actually be beneficial to the system to charge their AES projects. Demand charges with more dynamic time-variant rates would help to combine the best of both billing determinants.

5.3.4 Potential System Avoided Costs Achievable by AES Projects

Analysis of the sample of 189 nonresidential AES projects online prior to 1/1/2018 revealed that the system-level savings that could potentially have been realized in 2018 range from $48.44/kW to $298.93/kW, if the projects were dispatched to minimize system avoided costs (Figure 5-20). Almost 86 percent of projects could achieve system savings of at least $100/kW-year, or 8.33 $/kW-month.

FIGURE 5-20: DISTRIBUTION OF SYSTEM AVOIDED COSTS ATTRIBUTABLE TO NONRESIDENTIAL AES PROJECTS ONLINE BEFORE JANUARY 1ST 2018 IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH, $ PER KW OF REBATED CAPACITY (N=189)



The results for Q4 of 2018 analysis show a similar trend, but are smaller in magnitude compared to the annual results scaled to monthly values. As described in Section 5.2, system costs in 2018 peak between July and September primarily due to high generation, transmission and distribution capacity savings. Avoided cost impacts for Q4 are therefore expected to be much lower. There are more residential projects saving over $4/kW-month than nonresidential, likely because of the higher RTE of residential customers. However, the top 10 percent of nonresidential projects have significantly higher system cost savings than top residential AES projects. This is primarily because the top ranked nonresidential projects for system cost savings have much longer durations than the top ranked residential projects. Also note that it appears for nonresidential customers the system cost savings under customer dispatch are closer to the cost savings under system cost dispatch, when compared to equivalent values for residential customers. This implies nonresidential rates may be slightly better aligned with system costs, however without annual results for these customers this is difficult to confirm.

FIGURE 5-21: DISTRIBUTION OF SYSTEM AVOIDED COSTS ATTRIBUTABLE TO NONRESIDENTIAL AES PROJECTS ONLINE BEFORE OCTOBER 1ST 2018 IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH, $ PER KW OF REBATED CAPACITY (N=246)

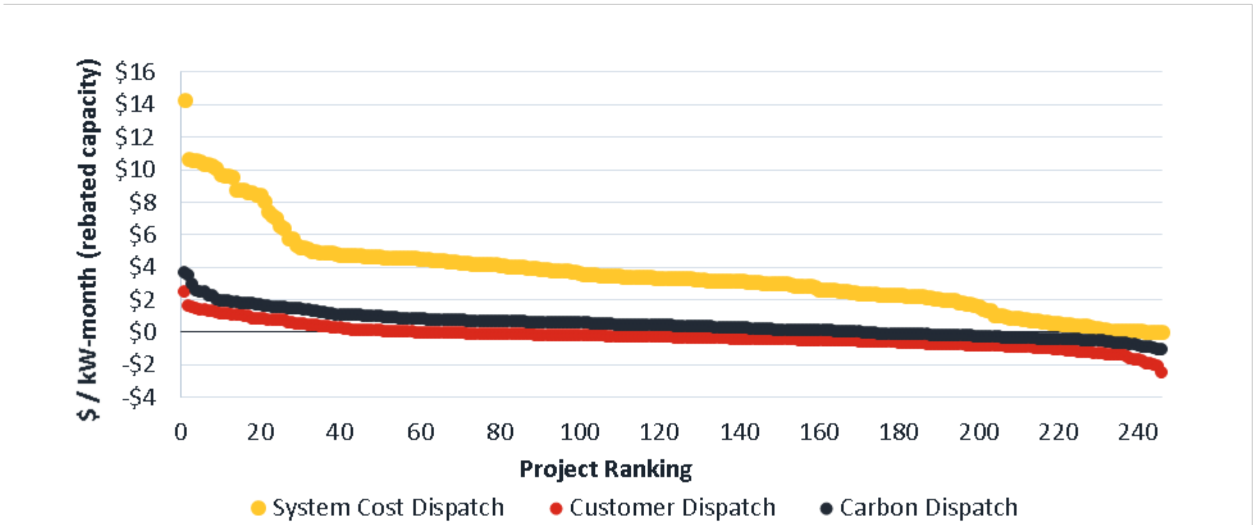


FIGURE 5-22: DISTRIBUTION OF SYSTEM AVOIDED COSTS ATTRIBUTABLE TO RESIDENTIAL AES PROJECTS ONLINE BEFORE OCTOBER 1ST 2018 IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH, $ PER KW OF REBATED CAPACITY (N=164)

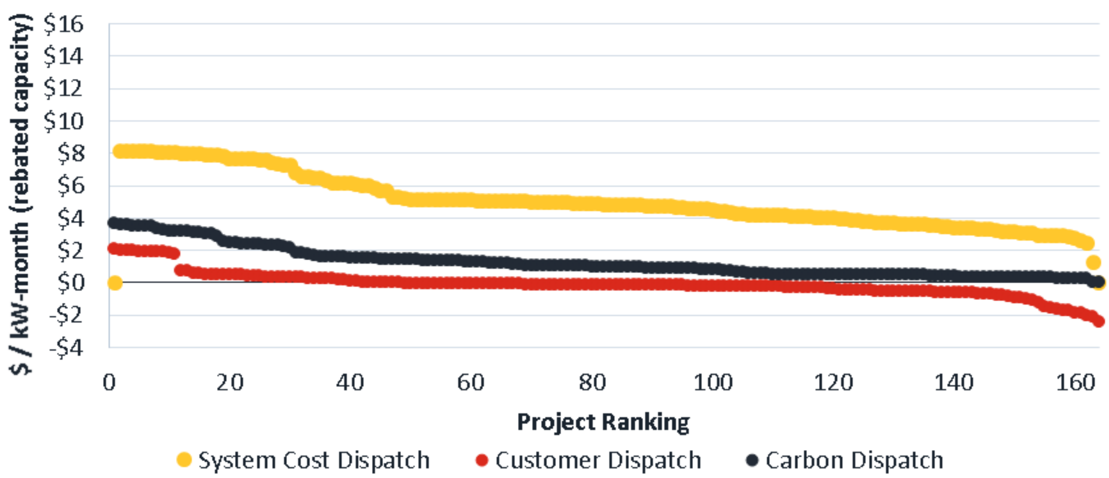


Figure 5-23 and Figure 5-24 highlight that scaling up our project sample to the population of AES SGIP projects yields significant potential system cost savings. If the full population of nonresidential SGIP AES projects operating in 2018 were optimized on an hourly basis to minimize system marginal costs with perfect foresight, we estimate system savings of approximately $12.4 million in 2018, while residential projects could have achieved $2.8 million. On the other hand, optimizing dispatch to minimize customer bills would have saved only $2.9 million and $440,000 in system costs, for nonresidential and residential projects, over the year. Optimizing dispatch to minimize carbon dioxide emissions would have yielded net savings of about $4.9 million and $1.4 million, respectively, in 2018. Again, this suggests there is a disconnect between system costs, CO_2 emissions signals and customer rates.

As described in Section 5.3.2, the bill savings and carbon approaches offer far less arbitrage opportunities to incentivize the storage systems to cycle versus the utility dispatch approach. A majority of the avoided cost value can be captured in a small number of high-cost hours that are generation capacity and/or distribution capacity constrained. If these high cost hours are not well aligned with utility tariffs, then optimizing for customer bill savings will not translate to high system marginal cost reduction. System marginal emissions are strongly correlated to utility system costs therefore customers which are able to respond to high carbon price peaks can have significant impacts on system emissions. Therefore, under the carbon approach, system cost savings are generally larger than when maximizing bill savings. The top 5 AES projects show significantly higher system savings which are mainly AES projects with high roundtrip efficiencies that make it economically optimal for them to respond to more fluctuations in the carbon price signal.

FIGURE 5-23: ESTIMATED 2018 SYSTEM AVOIDED COSTS ATTRIBUTABLE TO THE POPULATION OF NONRESIDENTIAL SGIP AES PROJECTS OPERATING IN 2018 IF OPERATED UNDER OPTIMAL DISPATCH, BY OPTIMIZATION APPROACH, $2019 MILLIONS

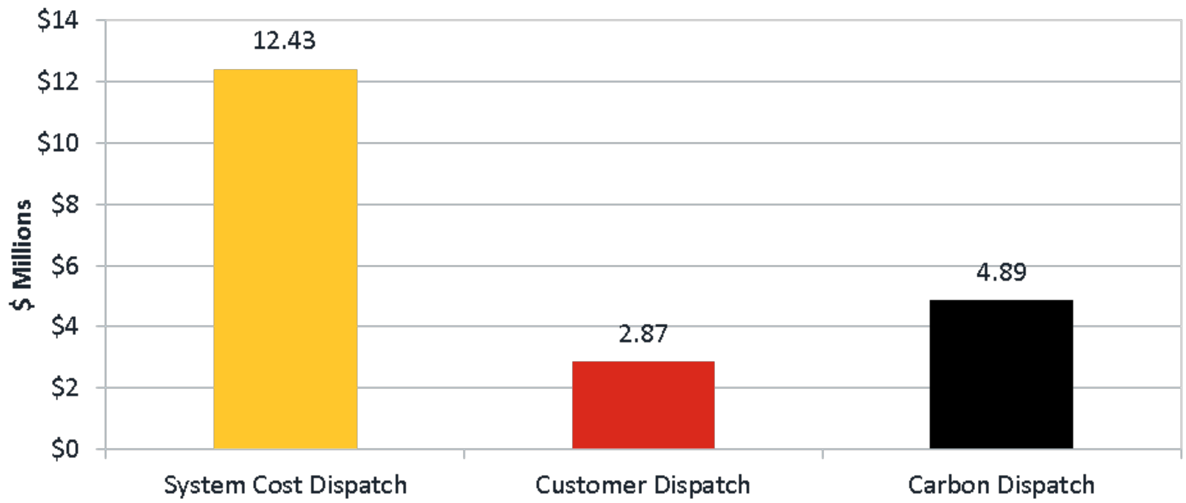
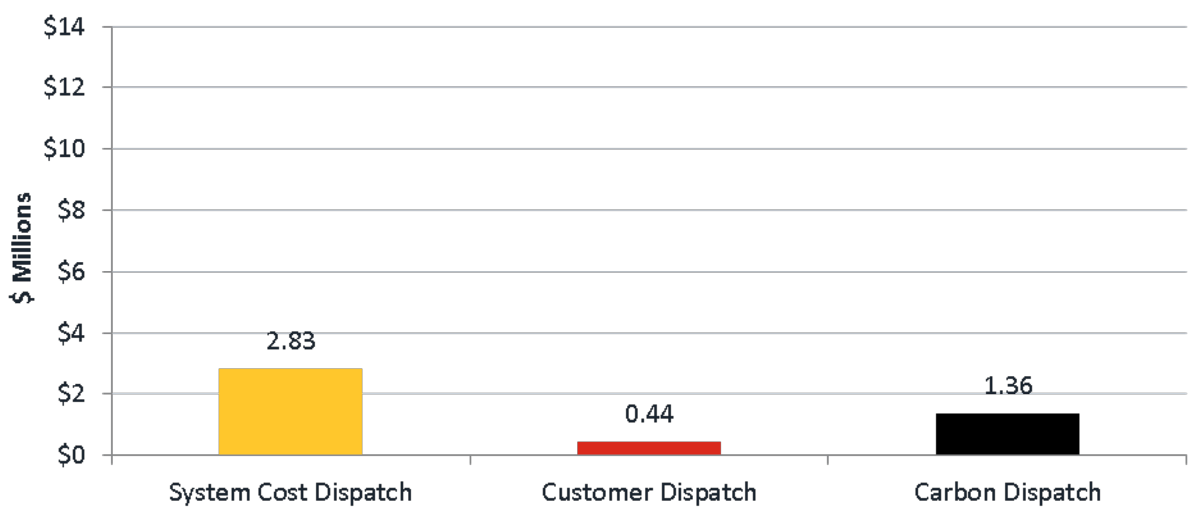


FIGURE 5-24: ESTIMATED 2018 SYSTEM AVOIDED COSTS ATTRIBUTABLE TO THE POPULATION OF RESIDENTIAL SGIP AES PROJECTS OPERATING IN 2018 IF OPERATED UNDER OPTIMAL DISPATCH, BY OPTIMIZATION APPROACH, $2019 MILLIONS



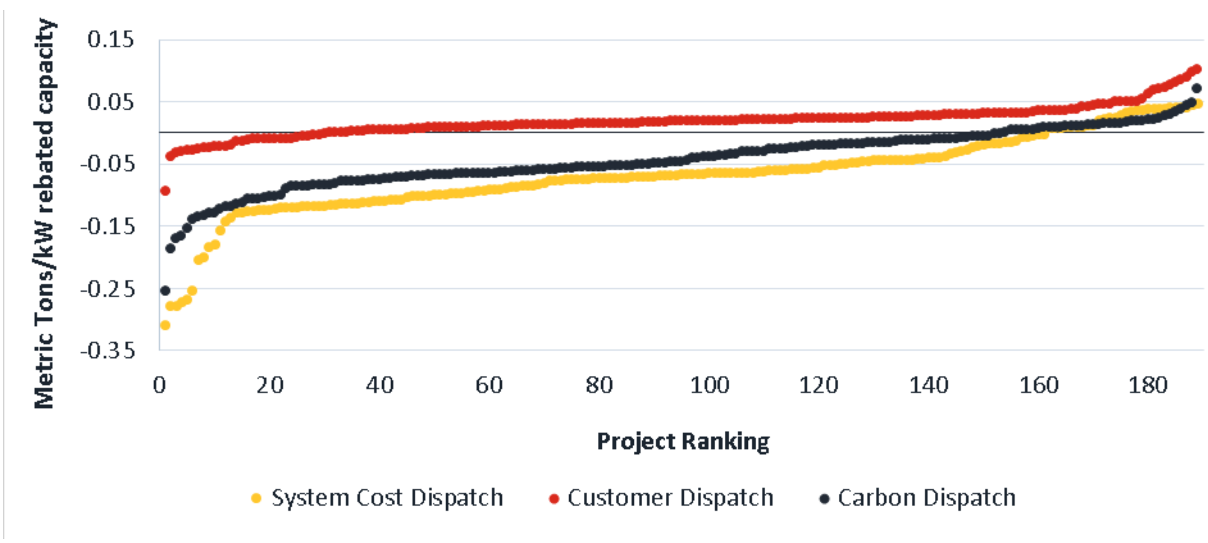
There are two important caveats to this system cost valuation for AES. First, as mentioned previously, the analysis operates under the assumption of perfect foresight to dispatch AES to minimize system costs.

Second, it assumes that a kW of storage can be dispatched perfectly so as to defer a kW of load increase. This depends significantly on the feeder load shape and hours of storage duration required to achieve a reliable peak load reduction. The peak load reduction also depends heavily on the program within which said storage is being dispatched. As discussed previously, certain rate structures do not effectively convey the economic cost to charging (or merely not discharging) for a small number of peak load hours in the year. More dynamic rate or dispatch signals would need to be provided to customers for behind-the-meter AES to reliably reduce distribution peak loads. Furthermore, the deferral value of a storage technology is only realized when an upgrade is *actually* deferred. This requires confidence on the part of system planners that the local storage will actually be dispatched to avoid a peak demand increase.

5.3.5 Potential Carbon Dioxide Savings Attributable to AES Projects

As described in Section 5.2, for the 2018 analysis we chose to co-optimize carbon emission reduction with customer bill savings to understand the maximum emission reduction potential customers could have achieved *without significantly impacting their electricity bills*. Under the carbon dispatch approach, for nonresidential projects online before 1/1/2018, 153 of the 189 AES projects in our sample would have reduced grid emissions compared with only 30 if dispatched for Bill Savings alone. The system costs dispatch showed the largest emission savings with 161 AES projects reducing emissions (Figure 5-25).

FIGURE 5-25: CO2 EMISSIONS SAVINGS BY NONRESIDENTIAL AES PROJECT ONLINE BEFORE JANUARY 1ST 2018, IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH (N=189)



As with the avoided cost savings results, the Q4 results show a similar general trend to the annual figures, but with more comparable magnitudes. While emission savings are higher during the spring / summer, the seasonal variation is not as dramatic as with system costs, so emissions savings are more consistent throughout the year. Also similarly to the utility avoided cost results for Q4, the residential customers show higher average emission reduction potential, but a narrower distribution of values.

FIGURE 5-26: CO2 EMISSIONS SAVINGS BY NONRESIDENTIAL AES PROJECT ONLINE BEFORE OCTOBER 1ST 2018, IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH (N=246)

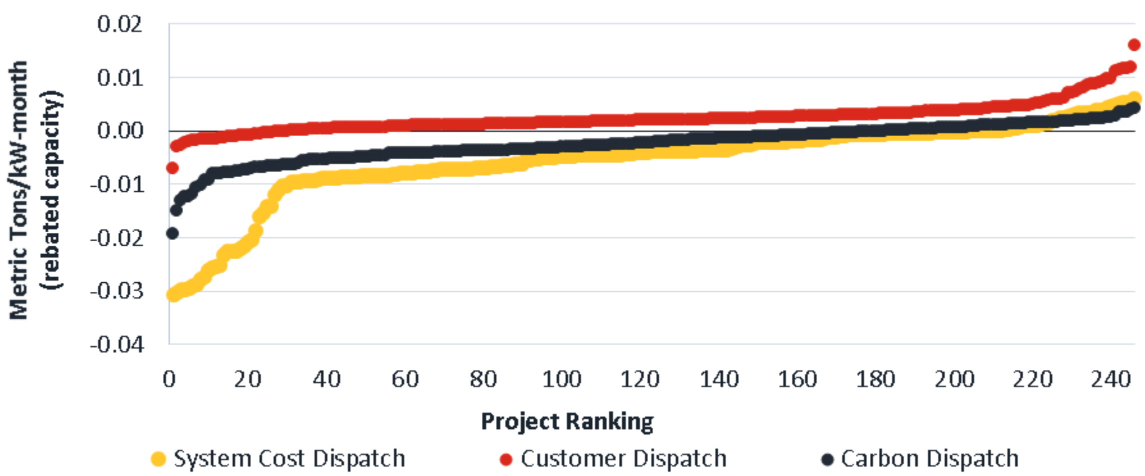
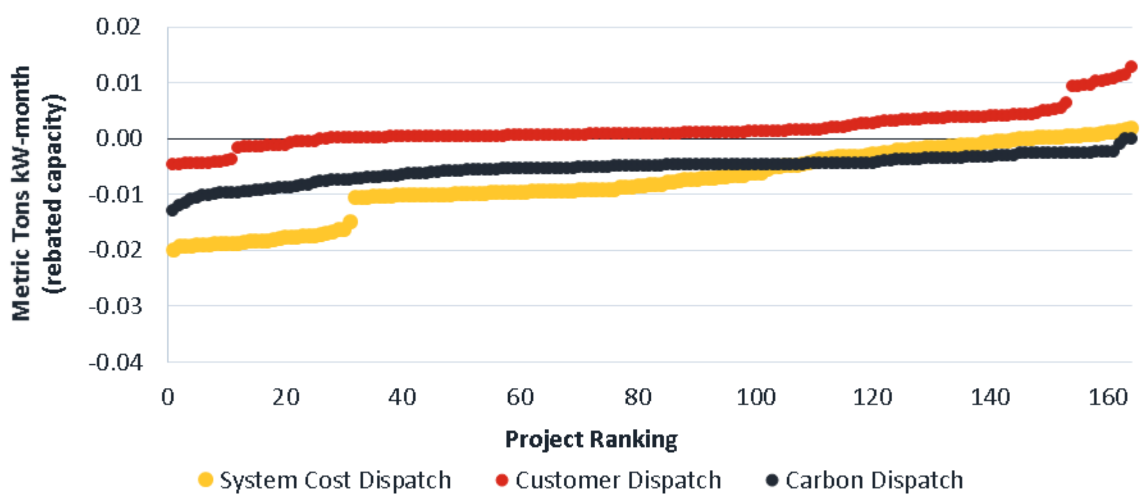


FIGURE 5-27: CO2 EMISSIONS SAVINGS BY RESIDENTIAL AES PROJECT ONLINE BEFORE OCTOBER 1ST 2018, IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH (N=164)



As described in Section 5.3.4, system costs are generally well correlated with carbon emissions. High system marginal emission hours often align with high system marginal cost hours when more inefficient plants are running, so optimizing for the system costs does result in large net reduction in CO_2 emissions. Under the carbon dispatch, the carbon price signal is rarely large enough relative to utility tariffs to shift charging behavior significantly away from the bill reduction dispatch pattern. Many AES project customers are on TOU tariff's and additional cycling to reduce emissions for these customers occurs primarily *within* TOU blocks, but charging is rarely shifted between TOU periods. Therefore, while the carbon dispatch approach shows marked improvement compared to the bill savings dispatch, the carbon price signal is still not sufficiently large enough to ensure all AES projects reduce grid emissions and is a worse incentive for grid emissions than system marginal costs alone. However, recall that under the carbon dispatch approach the AES projects are cycled significantly less than under the system cost approach and therefore have greater per cycle emission reductions.

In August, CPUC decision 19-08-001 mandated that all new nonresidential AES projects reduce annual grid emissions by at least 5kg per kWh of rebated capacity in order to receive their full SGIP incentive.[12] To further explore the implications of this CPUC decision, we performed additional analysis in which the new SGIP emission target and the penalty are directly modelled as an optimization constraint. These results are described in Section 5.3.7.

Scaling these results to the AES population suggests that the maximum potential avoided emissions in 2018 across the population of nonresidential AES SGIP projects would have been 7,458 metric tons of CO_2 (Figure 5-28). The maximum potential for residential AES projects would have been 1,660 metric tons of CO_2 (Figure 5-29). Optimally dispatching the AES projects to minimize carbon emissions also would have resulted in some carbon savings for both nonresidential (approximately 4,010 tons) and residential projects (approximately 1,920 tons). Optimizing to minimize customer bills under 2018 tariffs would have *increased* CO_2 emissions by around 1,920 tons and 330 tons for nonresidential and residential projects, respectively.

[12] See CPUC D. 12-11-005 available at:
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K260/310260347.PDF

FIGURE 5-28: ESTIMATED 2018 AVOIDED CO2 EMISSIONS ATTRIBUTABLE TO THE POPULATION OF NONRESIDENTIAL SGIP AES PROJECTS IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH

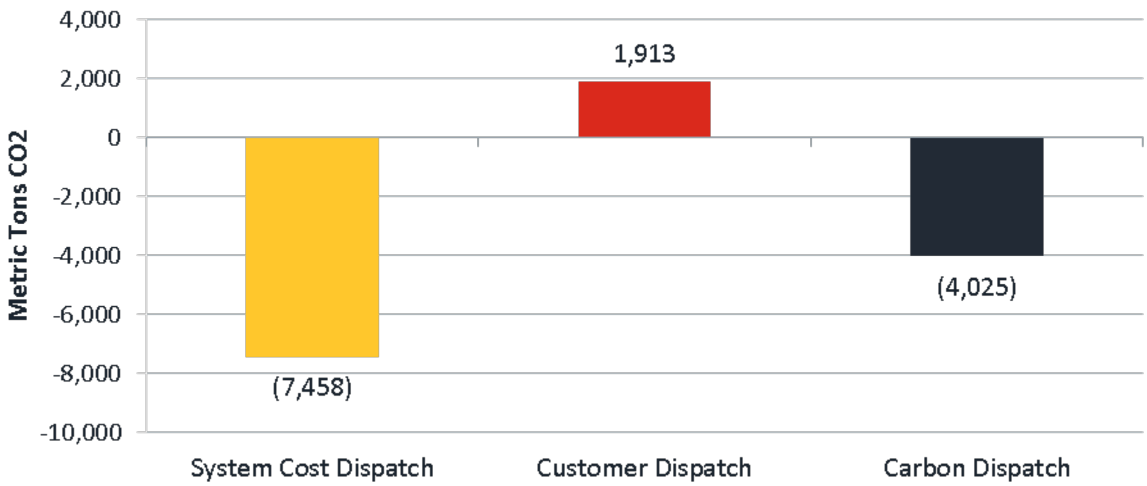
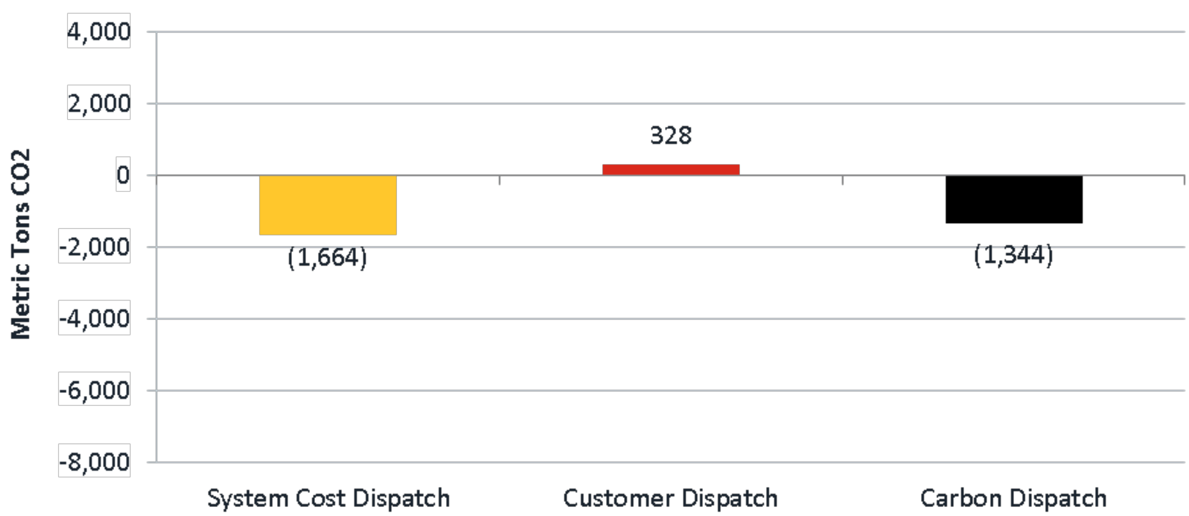


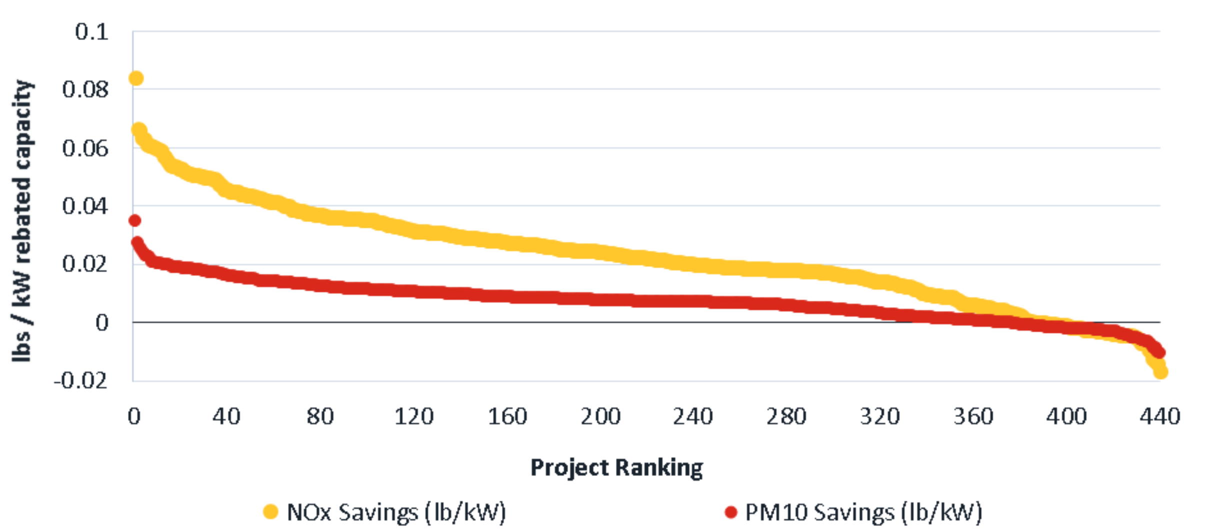
FIGURE 5-29: ESTIMATED 2018 AVOIDED CO2 EMISSIONS ATTRIBUTABLE TO THE POPULATION OF RESIDENTIAL SGIP AES PROJECTS IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH



The estimated emission increase under customer bill optimization for residential customers contrasts with the population estimates developed from observed impacts in Section 4. Observed impacts indicate residential customers reduced grid emissions based on their actual dispatch pattern in 2018. As described in Section 4, the primary reason for this was customers charging their storage assets from onsite PV. Under customer bill dispatch, residential customers were purely trying to minimize bill savings resulting in a very different dispatch pattern. To explore the impacts of charging purely from on-site PV a sensitivity analysis was performed (Section 5.3.7).

We have also conducted an examination of potential criteria pollutant savings (NOx and PM10) when projects are dispatched to minimize electric utility bills and carbon emissions. Those results are shown in the figure below.

FIGURE 5-30: ESTIMATED 2018 AVOIDED NOX AND PM10 EMISSIONS BY AES PROJECT, IF OPERATED UNDER OPTIMAL DISPATCH, CARBON DISPATCH APPROACH (N=441)



5.3.6 Summary Results of Optimized Dispatch

The total potential savings attributed to SGIP AES projects under ideal dispatch are summarized in Table 5-7 and Table 5-8 below.

TABLE 5-7: ESTIMATED POPULATION-LEVEL IMPACT OF NONRESIDENTIAL AES PROJECTS, 2018

	Customer Bill Dispatch Approach	System Cost Dispatch Approach	Carbon Dispatch Approach
Net Customer Bill Savings (Cost) ($ Millions)	$14.07	($17.16)	$13.99
Net System Benefit (Cost) ($ Millions)	$2.87	$12.43	$4.89
System CO2 Emissions (Reduced) (Metric Tons)	1,913	(7,458)	(4,025)

TABLE 5-8: ESTIMATED POPULATION-LEVEL IMPACT OF RESIDENTIAL AES PROJECTS, 2018

	Customer Bill Dispatch Approach	System Cost Dispatch Approach	Carbon Dispatch Approach
Net Customer Bill Savings (Cost) ($ Millions)	$0.847	($0.574)	$0.846
Net System Benefit (Cost) ($ Millions)	$0.440	$2.826	$1.362
System CO2 Emissions (Reduced) (Metric Tons)	328	(1,664)	(1,344)

These results demonstrate that, under current rates, the incentives for customers to dispatch AES to minimize their bills are not well aligned with the goals of minimizing system (and thereby ratepayer) costs or carbon dioxide emissions. More dynamic rates that better align customer and grid benefits could provide substantial ratepayer and environmental benefits that are currently unrealized. The Carbon Dispatch Approach results highlight the potential benefit of a relatively small price signal to the system while still enabling customers to achieve bill savings just as high.

5.3.7 Alternative Dispatch Approaches

This final results section describes some of the sensitivity runs performed to support our analysis. Each sensitivity explores an alternate incentive for dispatching storage assets under the SGIP program that differ from the three main dispatch approaches described in Section 5.2.

Implementing an Emission Cap

In August 2019, CPUC decision 19-08-001 mandated that, beginning April 1, 2020, all new nonresidential AES projects reduce annual grid GHG emissions by at least 5 kilograms (kg) of carbon dioxide per kWh of rebated capacity in order to receive their full SGIP incentive. If projects are found to reduce emissions less than 5kg per kWh or increase emissions over the year, they will have their annual incentive payment reduced by one dollar per kg ($1,000 per metric ton) of carbon dioxide they are over the 5kg per kWh reduction threshold.[13]

To evaluate the impact of this requirement on AES operation, we ran the RESTORE under the bill savings approach for the 109 nonresidential customers who received PBI payment and began normal operations prior to 1/1/2018, and subjected each project to the new decision 19-08-001. To model this emissions cap, we subtracted the GHG cost, if incurred, from the total revenue received by storage and ensured the GHG cost could be no greater than 100 percent of annual PBI payment.

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[13] See CPUC D. 12-11-005 available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K260/310260347.PDF

GHG cost = (annual emission of storage – annual emission cap) * $1 per kg of CO2

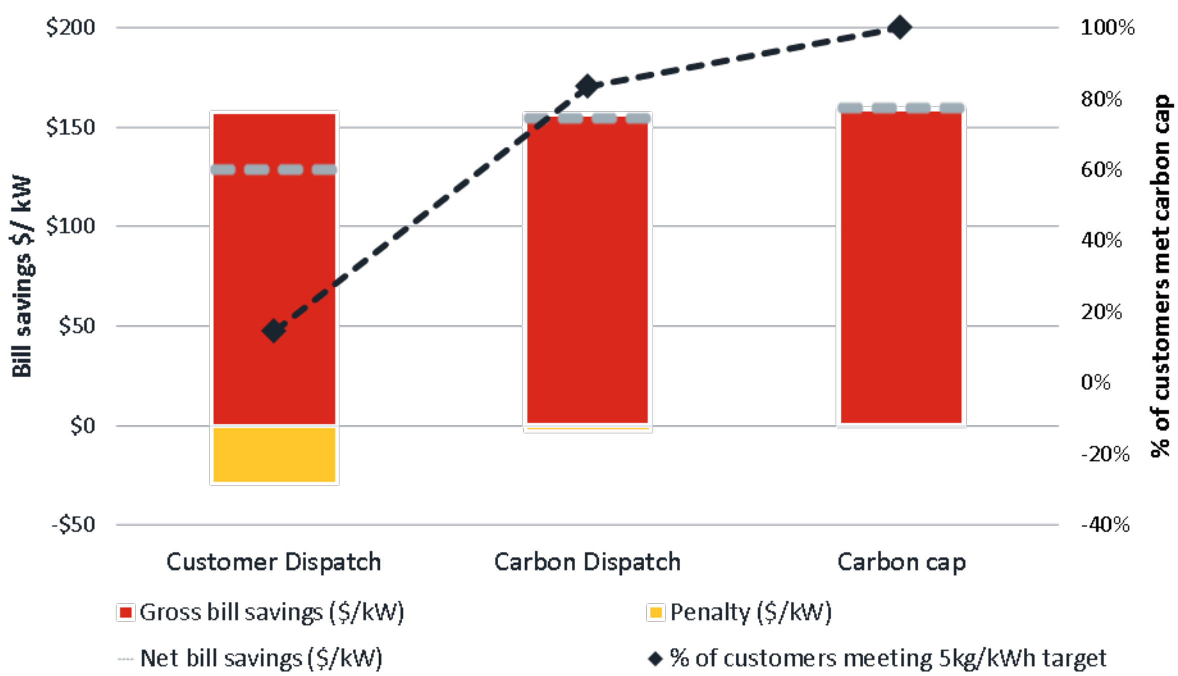
Annual emission cap = rebated capacity * 5kg per kWh

With the carbon cap imposed, RESTORE simulation shows all nonresidential PBI customers that started operations prior to 1/1/2018 could have complied with D. 19-08-001 without incurring any penalty. Since the penalty only applies if customers fail to meet the target, we assumed customers that were already outperforming the GHG cap did not change their dispatch pattern under Customer Bill Dispatch Approach.

To study the impact of D. 19-08-001 on bill savings, we compared our existing results from the customer bill dispatch approach and carbon dispatch approach to the carbon cap sensitivity. As a reminder, all three approaches assume perfect load and price foresight and have the following characteristics:

- Customer Bill Dispatch Approach: storage is dispatched to minimize a customer's monthly electricity bill
- Carbon Dispatch Approach: storage is dispatched to minimize both the customer's monthly electricity bill and marginal carbon dioxide emissions
- Carbon Cap Approach: storage is dispatched to minimize the customer's monthly electricity bill and reduce annual GHG emissions by 5 kg /kWh

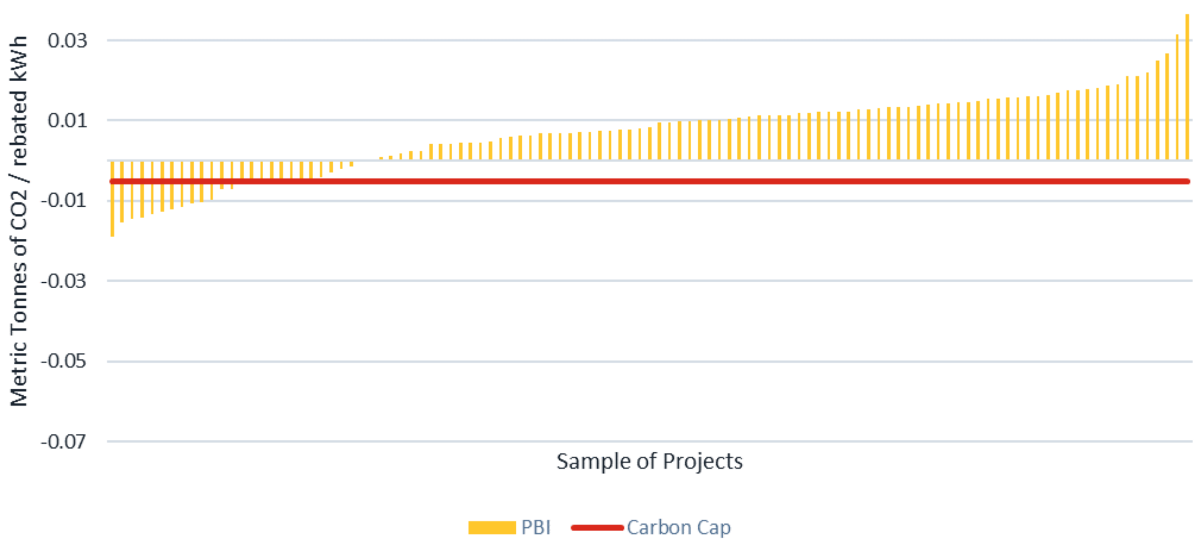
FIGURE 5-31: BILL SAVING COMPARISON ACROSS THREE DISPATCH APPROACHES



As shown in Figure 5-31, gross bill savings are similar across all three dispatch approaches. However, gross bill savings do not capture the cost that would be incurred by customers failing to meet the GHG cap. Calculating bill savings net of penalties shows the Carbon Cap Approach would have had the highest net benefit to the customer. Customers could have achieved an average net bill savings around $159.38/kW with 100 percent of customers meeting the 5kg/kWh target.

The impact of the carbon cap varies across projects with some easily meeting the cap, but not others. Figure 5-32 and Figure 5-33 illustrate the net emission of PBI customers under the Customer Bill Dispatch and the Carbon Dispatch Approach, benchmarked with the carbon cap of 5kg per kWh. In Figure 5-32, without a mandatory carbon cap, only a few customers can maximize bill savings and achieve the emission reduction goal of 5kg per kWh, simultaneously. In Figure 5-33, the carbon price signal incentivizes more customers to reduce emissions, but it is still not a strong enough incentive for some customers to reduce their emissions enough to meet the GHG cap. Therefore, a mandatory requirement on emission reduction for all PBI projects would have ensured that all nonresidential PBI customers reduced emissions by at least 5kg / rebated kWh.

FIGURE 5-32: NET CO2 EMISSIONS PER REBATED CAPACITY FOR PBI PROJECTS UNDER CUSTOMER BILL DISPATCH APPROACH



*Note that the y-axis unit is metric tons per rebated kWh rather than kW rebated capacity

FIGURE 5-33: NET CO2 EMISSIONS PER REBATED CAPACITY FOR PBI PROJECTS UNDER CARBON DISPATCH APPROACH

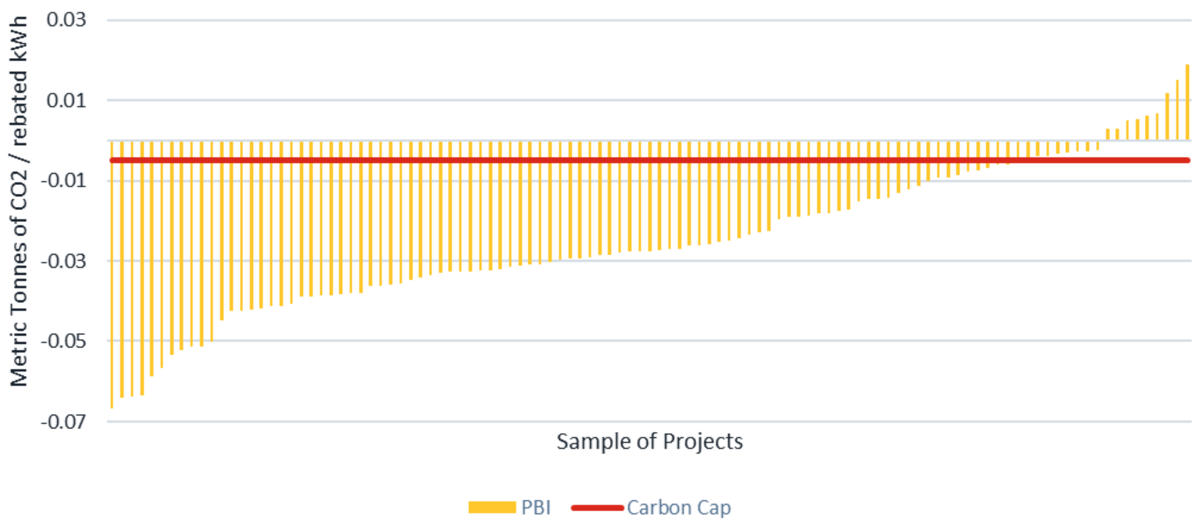
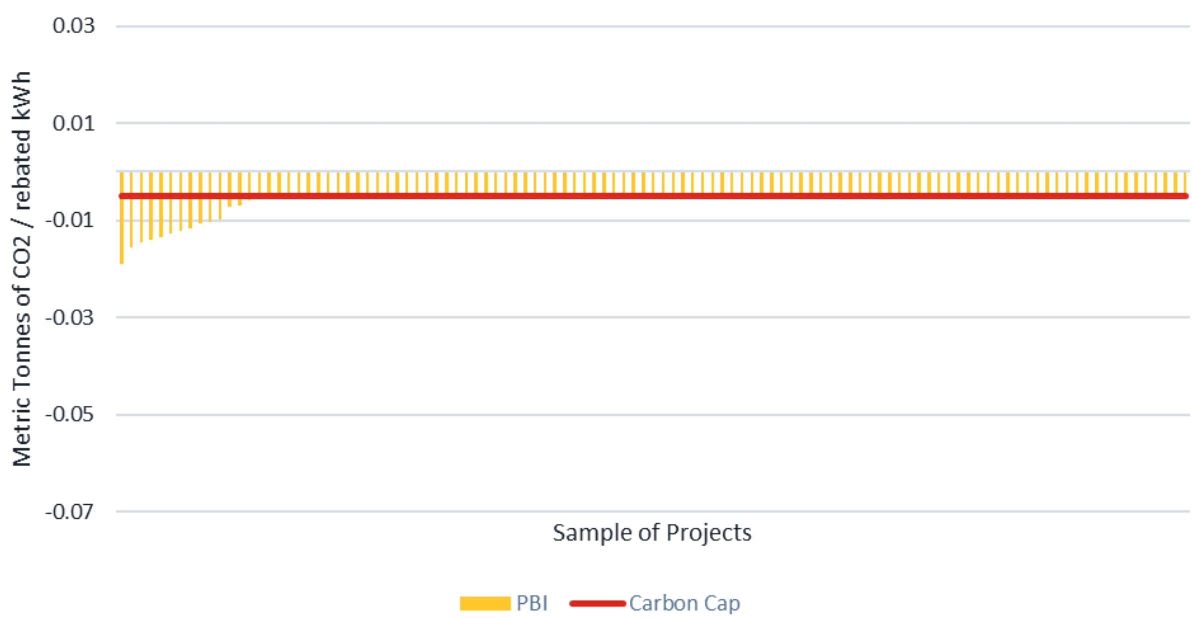


FIGURE 5-34: NET CO2 EMISSIONS PER REBATED CAPACITY FOR PBI PROJECTS UNDER CARBON CAP DISPATCH APPROACH



Commercial Customer Dynamic Rates

As with the 2017 analysis we conducted a sensitivity in which each nonresidential customer was put onto a more dynamic rate option offered by their utility. Recall that nonresidential AES customers are typically on TOU rates that use two to three different time periods per season (summer or winter), with each time block corresponding to different rates per kilowatt-hour. While TOU rates do a better job than simple flat rates at capturing general variations in utility system costs, more granularity is needed to truly capture the hourly fluctuations in system costs and greenhouse gas emissions. Therefore, we assigned each customer to a more dynamic rate option offered by their utility. The dynamic rate assignments are shown in Table 5-9 below.

TABLE 5-9: SIMULATED DYNAMIC RATE OPTIONS FOR SENSITIVITY ANALYSIS

Utility	Dynamic Rate
PG&E	The Peak Day Pricing (PDP) option for A-6, A-10, E-19, and E-20
SCE	The Real-Time-Pricing (RTP) option for TOU-GS-2, TOU-GS-3, and TOU-8
SDG&E	The Grid Integration Rate (GIR)

For PG&E, each customer was modeled on the Peak Day Pricing (PDP) version of their rate. PDP is an optional rate add-on that gives customers discounted rates during the summer season, in exchange for more expensive electricity during PDP "events." A PDP event can be called 9 to 15 times per summer season and lasts four hours. During the event hours, electricity is billed at a significantly higher rate (i.e. \$0.90 to \$1.20 per kilowatt-hour in 2018, depending on the tariff). For this analysis, RESTORE selected when the PDP events should occur based on the highest system cost days and called 12 events per customer.

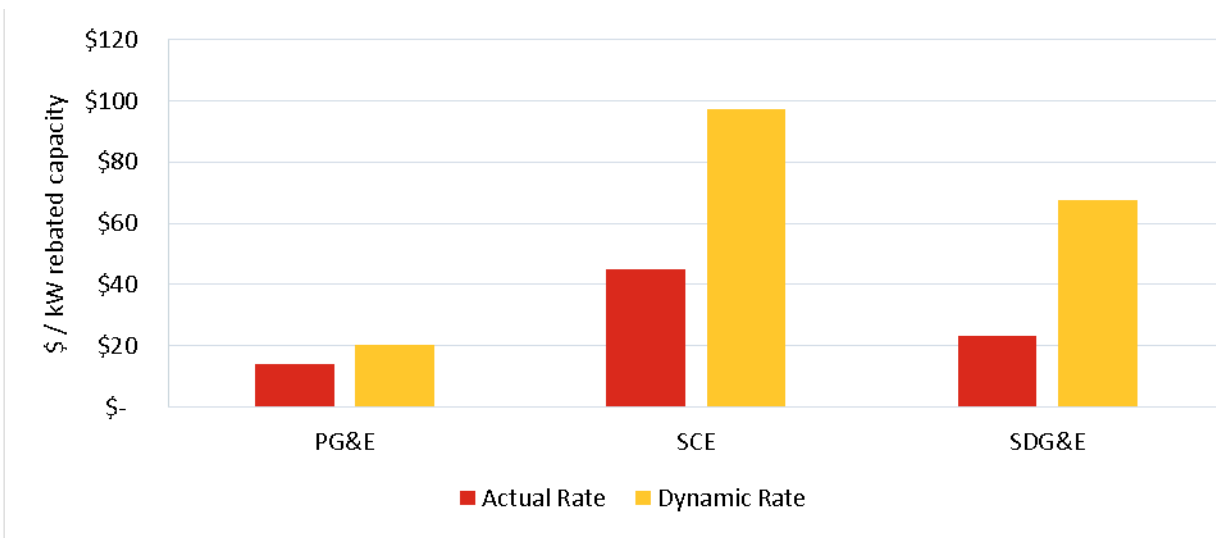
SCE customers were modeled on each rate's Real Time Pricing (RTP) version. The RTP rates are hourly rates, where each hour is assigned a rate value depending on 1) the season, 2) weekday or weekend and 3) the hourly temperature and how it fits in the tariff's designated temperature bands. We developed the RTP hourly rates based on 2018 temperature data and the rate values in SCE's RTP tariffs.

SDG&E customers were modeled on SDG&E's Grid Integration Rate (GIR). The GIR is the most dynamic of the IOU rates modeled in this analysis. Each hour is assigned a rate value based on 1) an hourly base rate, 2) an hourly commodity rate adjusted by the CAISO day-ahead hourly price and 3) an hourly distribution adder reflecting the top 200 annual hours of peak demand for the individual circuit. We created an estimated GIR hourly rate for this analysis based on 2018 CAISO data and a demand curve for a sample circuit. Currently, this rate is only available for electric vehicle charging. However, we use this rate as an example of hourly dynamic rates that could be used for storage systems in the future.

Each nonresidential customer in the sensitivity analysis was modeled under the Customer Bill Dispatch Approach on their new dynamic rate to test the impact of the AES project receiving a more variable price signal under the new rate option. We have compared the results of the dynamic rate sensitivity to the base case results of the Customer Bill Dispatch Approach, where each customer was modeled originally on their actual rate. The results showed that the more dynamic rate options increased each utility's average system cost savings, compared to when each customer's actual rate was modeled. This effect is shown in Figure 5-35. The dynamic rates attempt to better align with utility system costs than regular TOU rates, so this shows that the AES projects achieve this goal when modeled with perfect foresight using a dynamic rate option. PG&E customers improved system cost savings by a modest amount, and SCE and SDG&E customers experienced more substantial increases in system cost savings under the dynamic rate options.

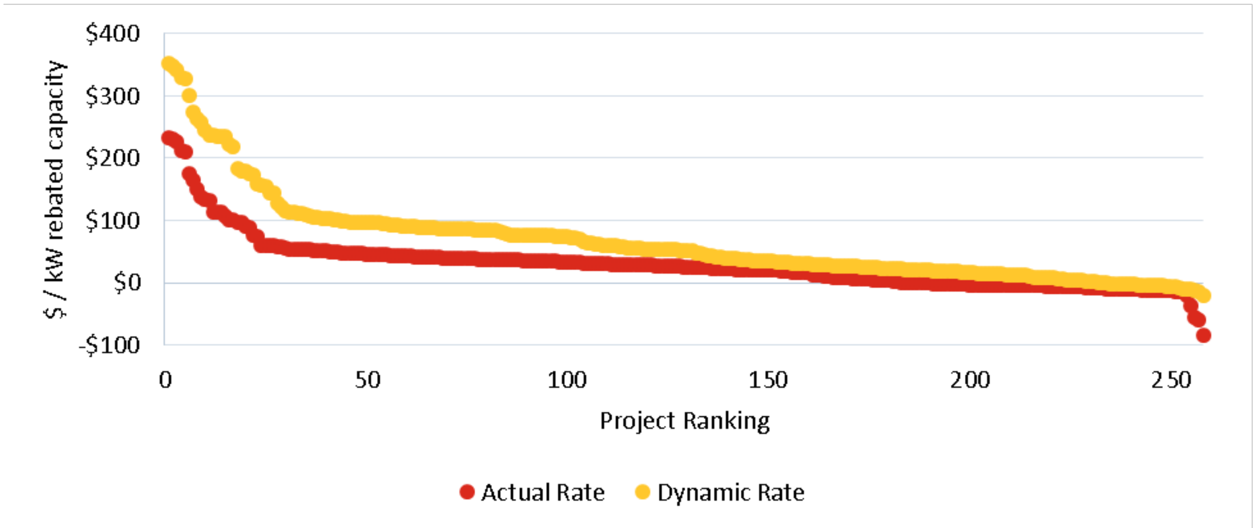
Dynamic rates improved PG&E customers' system cost savings by a modest amount, while SCE and SDG&E customers experienced more substantial increases in system cost savings under the dynamic rate options. The greater savings achieved by SCE and SDG&E customers were likely due to those rate values being more granular and based on hourly inputs, rather than just discrete events on certain days. This additional granularity in the hourly rates seems to allow for the model to reach greater utility cost savings, even when dispatching based on customer bills.

FIGURE 5-35: AVERAGE SYSTEM COST SAVINGS BY UTILITY FOR THE DYNAMIC RATE ANALYSIS COMPARED WITH CUSTOMERS' ACTUAL RATES



We can also consider system cost savings on a per project level. Figure 5-36 shows the project ranking for system cost savings under the dynamic rate scenario compared with the analysis using actual rates. As shown, the dynamic rate scenario creates an overall upward shift in system cost savings compared with actual rates. The dynamic rate case resulted in only 26 projects (out of 258 modeled with dynamic rates) with increased system costs (negative savings), compared with 73 projects increasing system costs when using actual rates.

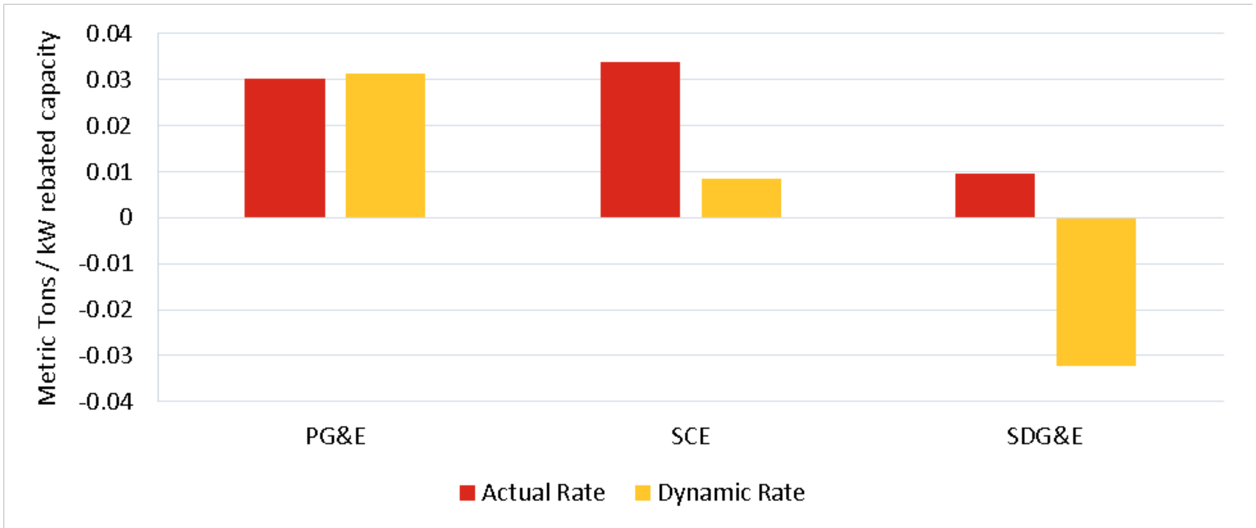
FIGURE 5-36: SYSTEM COST SAVINGS PER PROJECT FOR DYNAMIC RATES COMPARED WITH ACTUAL RATES (N=258)



In addition to increased system cost savings, the dynamic rate sensitivity demonstrated a general trend toward GHG emission improvements. Figure 5-37 shows the average CO_2 emissions per customer for each utility using the actual rates and the more dynamic rates. As shown in the chart, SCE customers decreased CO_2 emissions in the dynamic rate scenario on average, and SDG&E CO_2 emissions declined from net emissions to net CO_2 savings in the dynamic rate. The improvements in both cases make sense because the dynamic rates are based on utility system costs, which are typically well correlated with the grid's GHG emissions.

PG&E customers had relatively similar CO_2 emissions in both cases, with a slight increase in CO_2 emissions in the dynamic rate case relative to the actual rates. This result is likely different from the trend in SCE and SD&E's results due to the nature of each utility's dynamic rate structures. The PDP add-on modeled for PG&E only impacts discrete event days, compared with hourly rate changes used in the RTP rates for SCE and the GIR rate for SDG&E. The PDP events may not necessarily be called when grid emissions are the highest, and the events only impact certain days. This leads to greater GHG impacts from the more dynamic rates offered by SCE and SDG&E, with SDG&E's GIR rate offering the greatest GHG improvement.

FIGURE 5-37: AVERAGE CO2 SAVINGS BY UTILITY FOR THE DYNAMIC RATE ANALYSIS COMPARED WITH CUSTOMERS' ACTUAL RATES

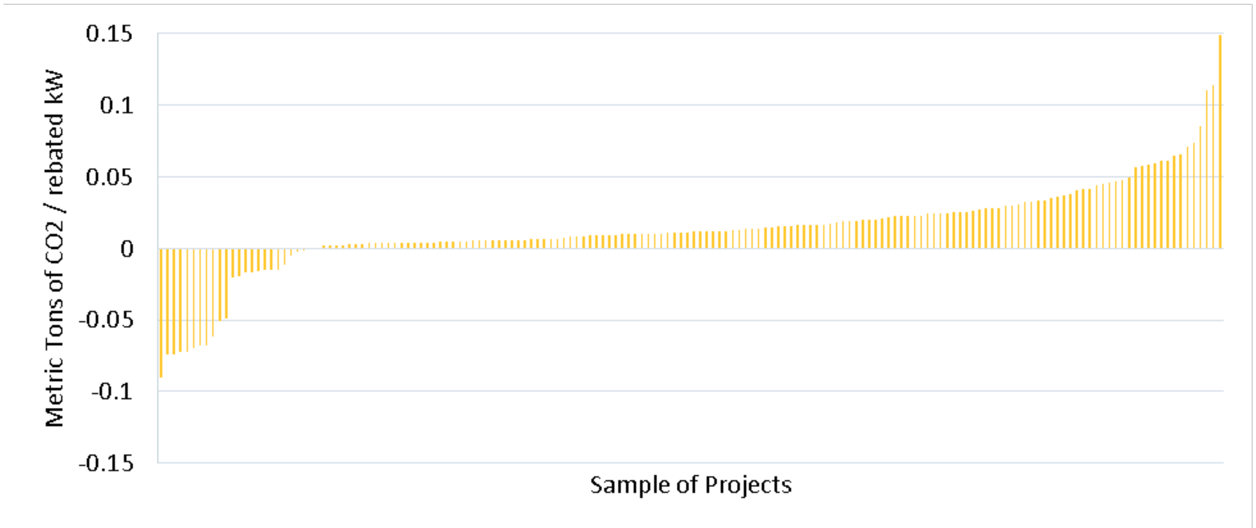


The dynamic rate sensitivity demonstrates the impact of more variable customer price signals on system cost savings and emission savings. The dynamic rates modeled here all show better alignment with system costs than static TOU rates. However, these dynamic rates encompass different amounts of complexity and granularity – with event-based rate adjustments at one end of the spectrum, to hourly variable rates based on CAISO prices at the other end. The overall results show that when rates are more directly tied to actual system costs (such as with SDG&E's GIR rate), there are more substantial impacts on system cost savings and emissions reductions. This result holds true even when dispatching based on customer bills, as we have done in this sensitivity analysis, because the additional granularity in the hourly rates allows for greater alignment between the rate seen by the customer and system costs or system emissions. More dynamic rates, beyond current TOU structures, may therefore enable the AES projects to provide greater grid benefits by aligning their bills with utility costs and system emissions.

Residential Customer Charging from PV

In Section 4.5.2, we observed that under actual operation in 2018, residential storage systems overall decreased GHG emissions. However, as shown in Section 5.3.5, had residential systems been optimally dispatched with perfect information to minimize bill savings they would have increased GHG emissions overall in 2018 (Figure 5-38). This discrepancy arises partly because the customer bill dispatch approach does not take the Investment Tax Credit (ITC) into consideration. Residential storage systems are eligible for the ITC only if they charge at least 100 percent from solar generation. Section 4.5.2 shows that residential customers are charging almost entirely from solar PV generation (Figure 4-41). Since periods of solar PV generation tended to coincide with low system marginal emission hours in 2018, charging during from PV provides a good incentive for reducing system emissions.

FIGURE 5-38: NET CO2 EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS UNDER CUSTOMER BILL DISPATCH APPROACH

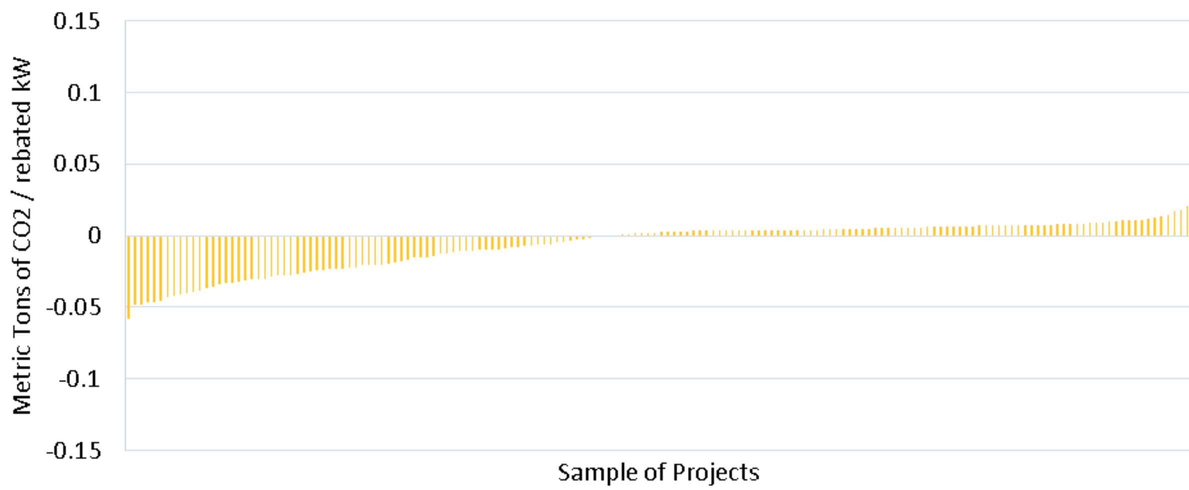


To further investigate the marginal emission impacts of charging from solar rather than optimizing for bill savings, a sensitivity run was conducted in which all customers were forced to charge 100 percent from solar PV generation. This is a hard constraint in RESTORE which resulted in 5 of the 169 runs being infeasible when forced to charge from solar, since the minimum cycling requirements were also still applied (and pro-rated to account for different start times for normal operations) and in these cases, PV generation was not sufficient to meet the cycling constraint.

Figure 5-39 shows that when storage systems are forced to charge entirely from on-site solar, only 89 projects out of 169 projects would have increased GHG emissions and the overall GHG emission impact of the 2018 fleet would have been negative. This result is consistent with the real dispatch behavior observed by the evaluation team in 2018. Also note that when the customers were forced to only charge from solar, the storage systems were cycled on average 36 percent less than when being dispatched for bill savings. Based on these sample results we estimate the residential population would have reduced system emissions by 72 metric tons of CO2 in 2018, which is comparable to the results seen under actual dispatch in Section 4.8.

Overall this sensitivity indicates that it may have been the ITC requirement, rather than rates, that drove the emission reduction for residential storage systems in 2018.

FIGURE 5-39: NET CO2 EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS UNDER CUSTOMER BILL DISPATCH APPROACH AS THEY ARE REQUIRED TO CHARGE FROM SOLAR



APPENDIX A GREENHOUSE GAS METHODOLOGY

This appendix describes the methodology used to estimate the impacts on carbon dioxide (CO_2) emissions from Self-Generation Incentive Program (SGIP) advanced energy storage (AES) projects.

A.1 OVERVIEW AND BASELINE DISCUSSION

Five-minute carbon dioxide (CO_2) impacts are calculated for each SGIP project as the difference between the grid power plant GHG emissions for SGIP AES operations (either actual dispatch, as in Section 4, or optimized dispatch, as in Section 5) and the emissions for the assumed baseline conditions. Baseline GHG emissions are those that would have occurred in the absence of the SGIP AES project.

AES projects are eligible for SGIP incentives both as standalone AES technologies and paired with renewable generators such as solar photovoltaics (PV). For purposes of SGIP AES GHG impact calculations, there are three baseline scenarios to consider. Below we present each case with a brief description.

Scenario #1 – Standalone Storage

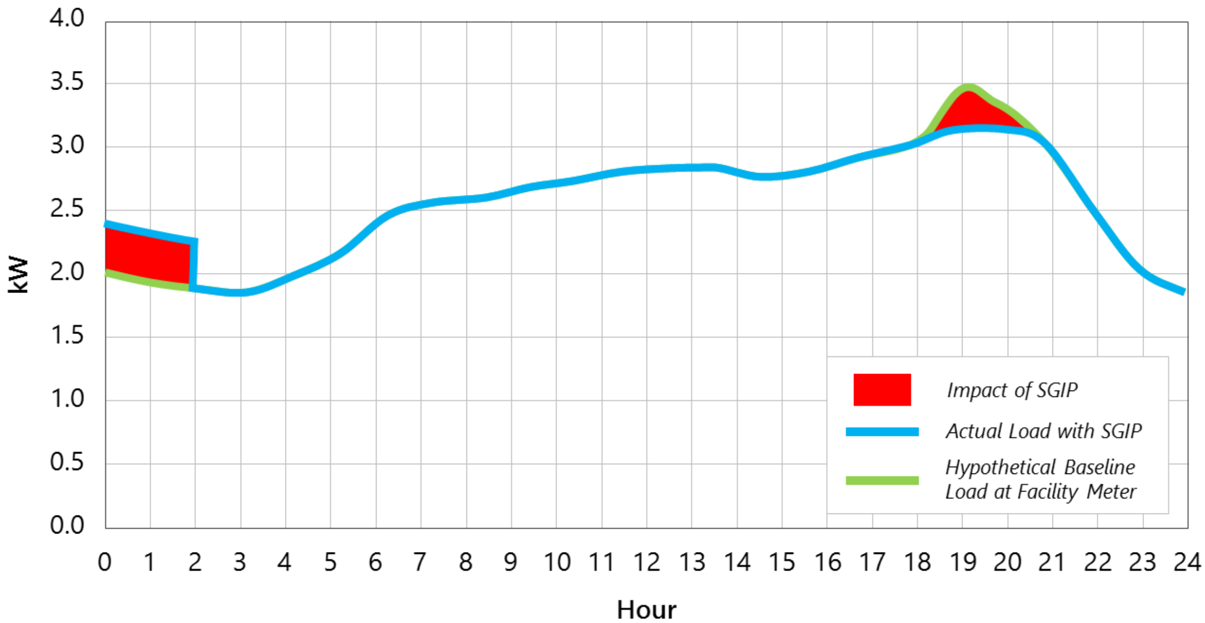
Scenario #1 applies to SGIP AES projects that are installed at facilities absent any additional on-site generation sources such as PV. Table A-1 summarizes the baseline and SGIP conditions in Scenario #1.

TABLE A-1: BASELINE AND SGIP CONDITIONS IN SCENARIO #1 (STANDALONE STORAGE)

Baseline	SGIP
Facility Loads	Facility Loads Storage charge and discharge

In Scenario #1 the 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 AES charging and discharging. This fact is reflected in an illustrative plot below of hourly grid power plant electricity use measured at a facility meter for the SGIP and Baseline conditions. The areas between these two lines represent AES charging (actual load with SGIP AES is higher than baseline load from midnight to 2 AM) and AES discharging (actual load with SGIP AES is lower than baseline load from 6:30 PM to 8:30 PM). During many hours (shown shaded blue) the loads for the two cases are identical. During these hours when the AES was idle no impacts are attributed to the SGIP.

FIGURE A-1: BASELINE AND SGIP CONDITIONS IN SCENARIO #1 (STANDALONE STORAGE)



Scenario #2 – Storage Paired with PV Not Attributed to SGIP

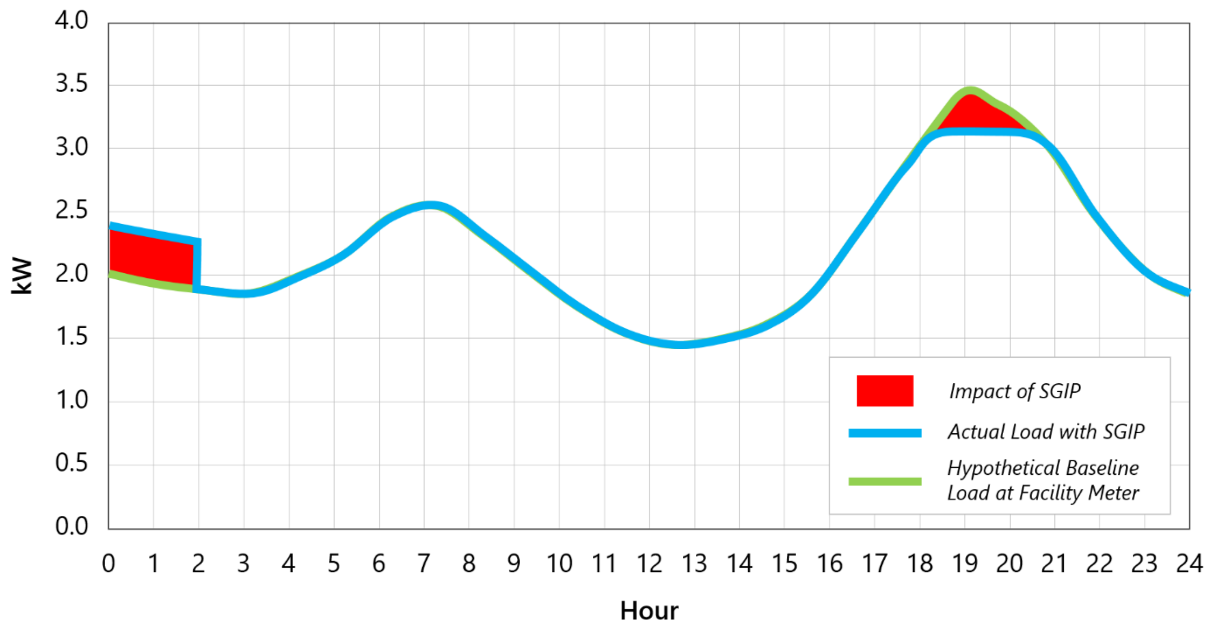
Scenario #2 applies to SGIP AES projects that are installed at facilities paired with on-site PV. The on-site PV in Scenario #2 is not attributed to SGIP meaning that the program did not influence its installation. Table A-2 summarizes the baseline and SGIP conditions in Scenario #2.

TABLE A-2: BASELINE AND SGIP CONDITIONS IN SCENARIO #2 (STORAGE PAIRED WITH PV NOT ATTRIBUTED TO SGIP)

Baseline	SGIP
Facility Loads PV generation	Facility loads PV generation Storage charge and discharge

In Scenario #2 both the facility loads and the PV generation 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 AES charging and discharging. This fact is reflected in an illustrative plot below of hourly grid power plant electricity use measured at a facility meter for the SGIP and Baseline conditions. The areas between these two lines represent AES charging (actual load with SGIP AES is higher than baseline load from midnight to 2 AM) and AES discharging (actual load with SGIP AES is lower than baseline load from 6:30 PM to 8:30 PM). During many hours (shown shaded blue) the loads for the two cases are identical. During these hours when the AES was idle no impacts are attributed to the SGIP.

FIGURE A-2: BASELINE AND SGIP CONDITIONS IN SCENARIO #2 (STORAGE PAIRED WITH PV NOT ATTRIBUTED TO SGIP)



Scenario #3 – Storage Paired with PV Attributed to SGIP

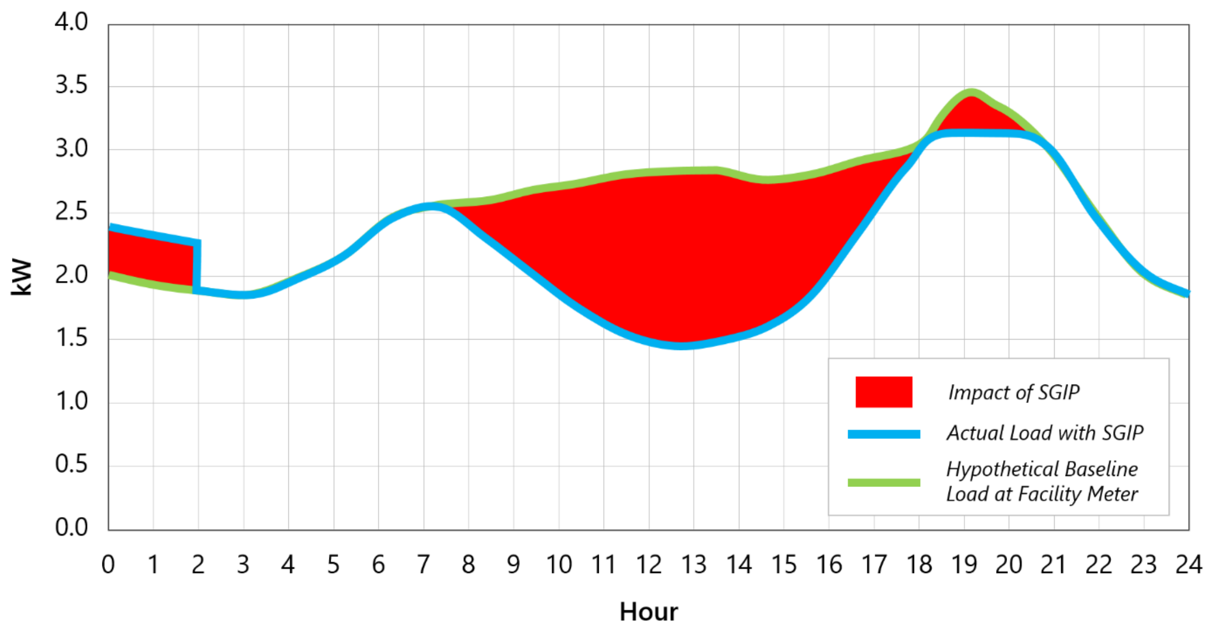
Scenario #3 applies to SGIP AES projects that are installed at facilities paired with on-site PV. The on-site PV in Scenario #3 is attributed to SGIP meaning that the program influenced its installation. Table A-3 summarizes the baseline and SGIP conditions in Scenario #3.

TABLE A-3: BASELINE AND SGIP CONDITIONS IN SCENARIO #3 (STORAGE PAIRED WITH PV ATTRIBUTED TO SGIP)

Baseline	SGIP
Facility loads	Facility loads PV generation Storage charge and discharge

In Scenario #3 the 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 the PV generation and the AES charging and discharging. This fact is reflected in an illustrative plot below of hourly grid power plant electricity use measured at a facility meter for the SGIP and Baseline conditions. The areas between these two lines represent AES charging (actual load with SGIP AES is higher than baseline load from midnight to 2 AM), PV generation (actual load with SGIP is lower than baseline load from 7:30 AM to 6:00 PM), and AES discharging (actual load with SGIP AES is lower than baseline load from 6:30 PM to 8:30 PM). During numerous hours (shown shaded blue) the loads for the two cases are identical. During these hours when the AES and PV were idle no impacts are attributed to the SGIP.

FIGURE A-3: BASELINE AND SGIP CONDITIONS IN SCENARIO #3 (STORAGE PAIRED WITH PV ATTRIBUTED TO SGIP)



What About Hours When Storage is Charging from PV?

Thus far the representative examples in the three scenarios presented above have made the simplifying assumption that the storage is charging/discharging separately from hours of PV generation. The intent in making this assumption is to stress the importance of the baseline definition in quantifying GHG emission impacts.

It's tempting to assume that hours where AES is charging from onsite PV are somehow emissions free. This assumption is incorrect. During any such 'charging from renewables' interval the customer's demand for energy services (e.g., lighting, refrigeration) must continue to be met. Each kWh of renewables generation used for charging is a kWh that is no longer available to satisfy the customer's demand for energy services. To maintain delivery of lighting and refrigeration services, compared to the Baseline case additional power from the grid will be required during the 'charging from renewables' interval in the SGIP case.

The following charts illustrate hourly Baseline and SGIP grid power levels for a Scenario #2 customer. Program impacts are calculated hourly as the difference between the two power levels. The Baseline chart (Table A-4) reflects hypothetical conditions without AES, where PV is satisfying some of the customer's demand for energy services, and grid power satisfies remaining demand unmet by PV.

FIGURE A-4: HYPOTHETICAL BASELINE FOR SCENARIO #2 CUSTOMER

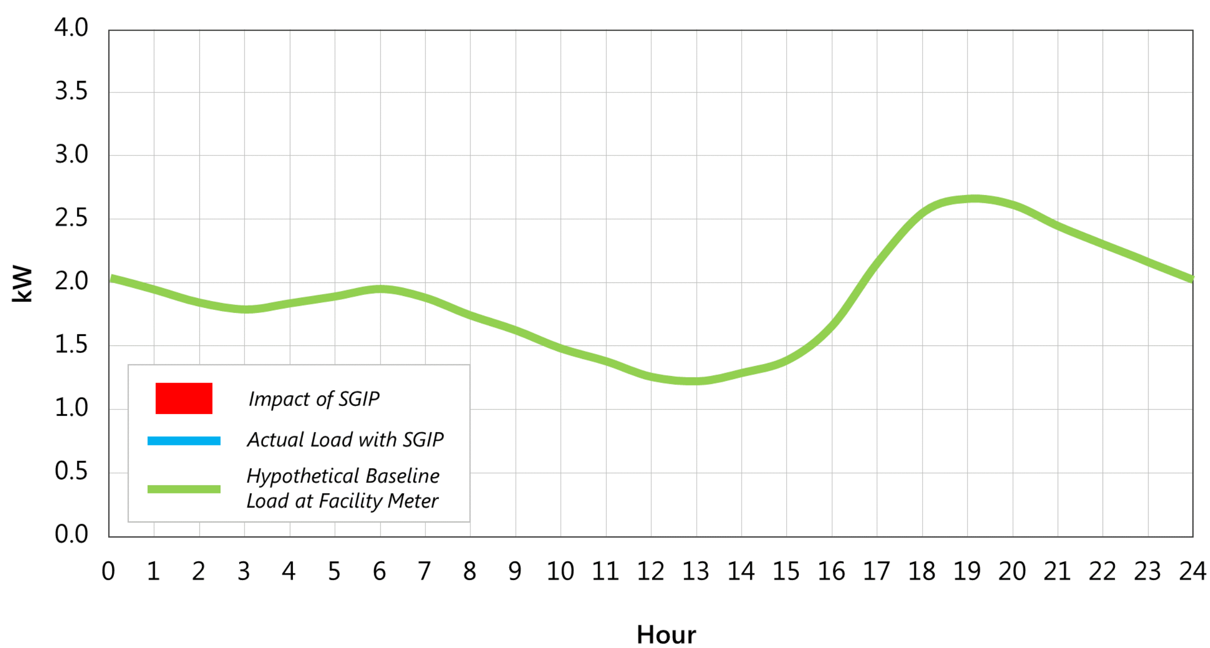


Figure A-5 reflects actual SGIP conditions, where AES is charging from renewables and then discharging in the evening. In the evening, during discharge, grid power levels for the customer are lowered. In the middle of the day, during charging from renewables, grid power levels for the customer are higher compared to the Baseline (i.e., no AES) case.

FIGURE A-5: SGIP CONDITION FOR SCENARIO #2 CUSTOMER CHARGING FROM RENEWABLES

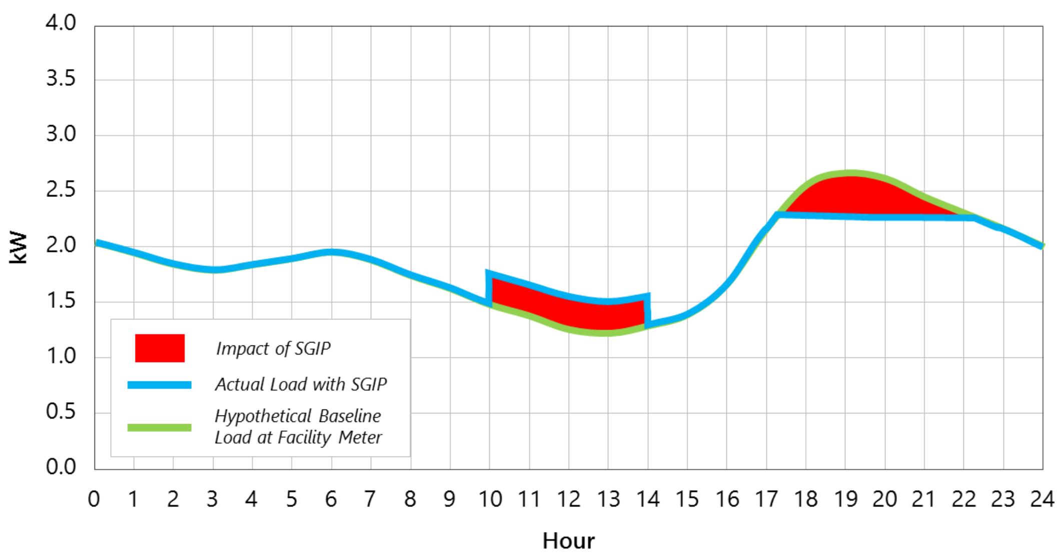
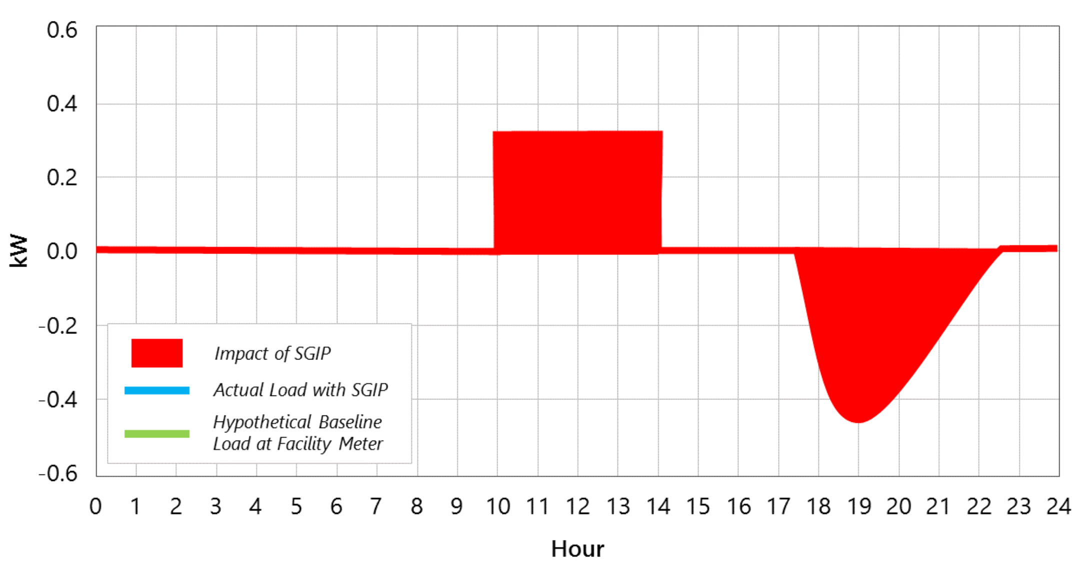


Figure A-6 summarizes the SGIP impact of AES projects in Scenario #2 charging from renewables. Most notably, program impacts are not influenced by PV in any way. PV generation only influences SGIP impacts in Scenario #3 where the SGIP influences the installation of PV.

FIGURE A-6: IMPACT OF SGIP FOR SCENARIO #2 CUSTOMER CHARGING FROM PV



A.2 GHG EMISSION IMPACT CALCULATIONS

Power plant emissions associated with grid power are the only source of greenhouse gas emissions in the impacts calculation. Facility loads do not inherently emit greenhouse gas, and neither do the other energy resources (PV, AES) in this analysis. Consequently, the impacts of SGIP AES on greenhouse gas emissions can be assessed by calculating the difference in power plant generation between the Baseline and SGIP conditions and then estimating the corresponding difference in greenhouse gas emissions. These calculations are outlined below.

First, the Baseline and SGIP conditions are described completely in terms of balance between electric load and electric supply for each project *i* and hour *h*. For each project, the appropriate baseline scenario (#1, #2, or #3) is selected.

We begin by stating that during each hour the total energy supply is equal to the demand. The facility loads for the Baseline and SGIP conditions are assumed identical. That is to say, the energy consumed by an SGIP customer facility to serve facility loads (lighting, refrigeration, etc.) remains constant between the Baseline and SGIP conditions. In doing so we can define a variable $LOAD_{ih}$ in two ways: the load served in the Baseline condition (Eqn. 1) and the load served in the SGIP condition (Eqn. 2):

$$LOAD_{ih} = basePV_{ih} + basePp_{ih}$$ Eqn. 1 (Baseline)

$$LOAD_{ih} = sgipPV_{ih} + AES_{ih} + sgipPp_{ih}$$ Eqn. 2 (SGIP)

Where:

- $LOAD_{i,h}$ is the end use facility load for the customer with SGIP AES project *i* during hour *h.*
  - Units: kWh
  - Basis: End use facility load for lights, appliances, plug loads, electric air conditioning, etc.
- $basePV_{i,h}$ is the hypothetical baseline electric generation from PV for the customer with SGIP AES project *i* during hour *h.*
  - Units: kWh
  - Basis: Positive values for generation

— Values (see table below):

Scenario	$basePV_{ih}$ Value	Source / Notes
Scenario #1	0 – In this scenario the customer never installed PV	
Scenario #2	Hypothetical PV generation for project i during hour h – in this scenario the SGIP customer would have installed PV in the absence of the program	Varies due to weather and system configuration. Source would be metered data or simulation.
Scenario #3	0 – In this scenario the customer would ***not*** have installed PV in the absence of the program	

- $sgipPV_{i,h}$ is the actual electric generation from PV for the customer with SGIP AES project *i* during hour *h.*

  — Units: kWh

  — Basis: Positive values for generation

  — Values (see table below):

Scenario	$sgipPV_{ih}$ Value	Source / Notes
Scenario #1	0 – In this scenario the customer never installed PV	
Scenario #2	PV generation for project i during hour *h* – in this scenario the SGIP customer installed PV	Varies due to weather and system configuration. Source would be metered data or simulation.
Scenario #3	PV generation for project i during hour *h* – in this scenario the SGIP customer installed PV	Varies due to weather and system configuration. Source would be metered data or simulation.

- $basePp_{i,h}$ is the hypothetical baseline power plant electricity use for the customer with SGIP AES project *i* during hour *h.*

  — Units: kWh

  — Basis: Positive values for import, negative values for net export.

- $sgipPp_{i,h}$ is the actual power plant electricity use for the customer with SGIP AES project *i* during hour *h.*

  — Units: kWh

  — Basis: Positive values for import, negative values for net export.

- $AES_{i,h}$ is the electrical output of SGIP AES project *i* during hour *h.*
  - Units: kWh
  - Basis: Positive while discharging, negative while charging

Next, we rearrange Eqn. 1 and Eqn. 2 to solve for power plant generation in the baseline ($basePp_{ih}$) and SGIP ($sgipPp_{ih}$) conditions:

$$basePp_{ih} = LOAD_{ih} - basePV_{ih}$$ Eqn. 3 (Baseline)

$$sgipPp_{ih} = LOAD_{ih} - sgipPV_{ih} - AES_{ih}$$ Eqn. 4 (SGIP)

The difference in power plant generation is then calculated as the difference between Eqn. 4 and Eqn. 3:

$$\Delta Pp_{ih} = sgipPp_{ih} - basePp_{ih} = (LOAD_{ih} - sgipPV_{ih} - AES_{ih}) - (LOAD_{ih} - basePV_{ih})$$ Eqn. 5

Where:

- $\Delta Pp_{i,h}$ is the power plant electricity impact of SGIP project *i* during hour *h.*
  - Units: kWh
  - Basis: Positive values indicate increase in grid power plant electricity use.

We see in Eqn. 5 that the $LOAD_{ih}$ term cancels out of the equation. The treatment of the PV term will vary for each scenario:

Scenario #1 – Standalone Storage

In Scenario #1 there is no PV in the Baseline condition or the SGIP condition. Therefore:

$$sgipPV_{ih} = basePV_{ih} = 0$$ Eqn. 6

Therefore, we can rewrite Eqn. 5 as follows for Scenario #1:

$$\Delta Pp_{ih} = -AES_{ih}$$ Eqn. 7

The hourly energy impacts of AES in Scenario #1 are equal to the net charge/discharge from the AES project. The negative sign indicates that a discharge (positive value for AES_{ih}) will result in a reduction of power plant electricity generation.

Scenario #2 – Storage Paired with PV Not Attributed to SGIP

In Scenario #2 there is PV in the Baseline condition (PV would have existed in the absence of the program) and also in the SGIP condition. Therefore:

$$sgipPV_{ih} = basePV_{ih} = PV_{ih} \qquad \text{Eqn. 8}$$

Therefore, we can rewrite Eqn. 5 as follows for Scenario #2:

$$\Delta Pp_{ih} = -AES_{ih} \qquad \text{Eqn. 7}$$

The hourly energy impacts of AES in scenario #2 are equal to the net charge/discharge from the AES project. When the installation of PV is not attributed to the SGIP, the PV terms cancel out and do not influence the energy impact calculation.

Scenario #3 – Storage Paired with PV Attributed to SGIP

In Scenario #3 there is no PV in the Baseline condition (PV would not exist in the absence of the program) but it **does** exist in the SGIP condition. Therefore:

$$basePV_{ih} = 0 \qquad \text{Eqn. 9}$$

Therefore, we can rewrite Eqn. 5 as follows for Scenario #3:

$$\Delta Pp_{ih} = -AES_{ih} - sgipPV_{ih} \qquad \text{Eqn. 10}$$

Note that it is only in Scenario #3 where PV generation affects the energy impact calculation. In Scenario #3, solar PV generation (positive value of $sgipPV_{ih}$) results in a substantial reduction of power plant electricity generation. Most importantly, the energy impacts from AES and PV are completely independent in how they influence overall power plant generation. For purposes of SGIP GHG impacts calculation, it is not necessary for the AES to charge during hours when PV is generating.

Finally, once the hourly power plant electricity impact of the SGIP project is calculated, the greenhouse gas emissions impact corresponding to the difference in grid power plant generation is calculated. The location- and hour-specific CO_2 emission rate, when multiplied by the difference in grid generation, estimates the hourly emissions impact.

$$\Delta GHG_{ih} = CO2EF_{ih} \cdot \Delta Pp_{ih} \qquad \text{Eqn. 11}$$

Where:

- $\Delta GHG_{i,h}$ is the GHG emissions impact of SGIP project *i* during hour *h.*
  - Units: Metric Tons CO_2eq / hr

Basis: Negative values indicate GHG emissions reduction during AES discharge. Positive values indicate GHG emission increase during AES charging.

- $CO2EF_{rh}$ is the CO_2 emission rate for region *r* (northern or southern California) for hour *h.*
  - Source: Energy + Environmental Economics, based on CAISO market data
  - Units: Metric Tons / kWh

A.3 MARGINAL GHG EMISSIONS RATES

The marginal grid generator is defined as the lowest cost dispatch power plant that would have behaved differently if the SGIP AES project were not charging/discharging during that same hour.

For our base case, E3 calculates the marginal rate of carbon emissions using a slight modification to the historical avoided cost model method adopted by the CPUC. Assuming that natural gas is the marginal fuel in all hours, the emissions rate of the marginal generator is calculated based on the 5-minute real-time[1] market price curve (with the assumption that the price curve also includes the cost of CO_2):

HeatRate[t] = (MP[t] – VOM) / (GasPrice + EF * CO_2Cost)

Where:

- MP is the 5-minute real time market price of energy (including cap and trade costs)
- VOM is the variable O&M cost for a natural gas plant

[1] The previous SGIP impact evaluation report used a marginal heat rate dataset based on the day-ahead market price curve. Empirical observations of curtailment events suggest that they are addressed far more often in the real-time market than the day-ahead market. Additionally, as AES projects are not under any hard constraint for operations, and the total storage capacity of AES projects compared to system-level load is small, system operators are unlikely to depend on any shifts in load as a firm behavior that bears influence in the day-ahead market. Because we are interested in the marginal impact of SGIP, any alteration in electricity demand attributed to SGIP is likely to be addressed in real-time, rather than in the day-ahead market. For these reasons, the market signal underlying the marginal emissions rate methodology was changed from the day-ahead to the real-time energy market.

- GasPrice is the cost of natural gas delivered to an electric generator
- CO_2Cost is the $/ton cost of CO_2
- EF is the emission factor for tons of CO_2 per MMBTU of natural gas

The link between higher market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency (therefore higher marginal cost) generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. Particularly high market prices can reflect other factors in the market such as unplanned outages or transmission constraints. If the E3 approach is applied to these extremely high market prices, the implied marginal generator would have a heat rate that exceeds anything believed to physically exist in the CAISO. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of natural gas technologies. The maximum and minimum emissions rates are bounded by a range of heat rates for proxy natural gas plants shown in Table A-4. We updated the high efficiency plant heat rate by lowering it from 6,900 to zero Btu/kWh, to reflect that hours with low implied marginal heat rates may represent averaging of marginal fossil fuel and renewable resources within that hour, either temporally or spatially.

TABLE A-4: BOUNDS ON ELECTRIC SECTOR CARBON EMISSIONS USING AVOIDED COST CALCULATOR METHODOLOGY

Baseline	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	12,500	0

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 2018 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,
- Interval load data provided by the electric utilities, and
- Interval storage provided by the Itron meters.

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 AES projects match the application data and to ensure they meet minimum requirements for program eligibility. Itron 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 advanced energy storage (AES) charge and discharge data are requested and collected from system manufacturers for non-performance based incentive (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 2018. These data were requested to allow analysis of noncoincident peak (NCP) demand impacts and to better analyze AES 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 as well as whether the data were received for analysis.

TABLE B-1: AES DATA SOURCES (REQUESTED AND RECEIVED)

PA	Project Type	PBI	IOU Interval Load Data		Project Developer Data		PBI System Data	
			Requested	Received	Requested	Received	Requested	Received
PG&E	Nonresidential	N	110	109	103	96		
	Nonresidential	Y	61	61	51	50	61	61
	Residential	N			1,105	781		
	All		**171**	**170**	**1,259**	**927**	**61**	**61**
SCE	Nonresidential	N	108	84	69	67		
	Nonresidential	Y	112	105	108	106	112	112
	Residential	N			878	559		
	All		**220**	**189**	**1,055**	**732**	**112**	**112**
CSE	Nonresidential	N	80	80	72	70		
	Nonresidential	Y	59	55	57	57	60	60
	Residential	N			291	154		
	All		**139**	**135**	**420**	**281**	**60**	**60**
SCG	Nonresidential	N	1	0	2	2		
	Nonresidential	Y	5	5	5	5	5	5
	Residential	N			85	50		
	All		**6**	**5**	**92**	**57**	**5**	**5**

B.2 DATA CLEANING

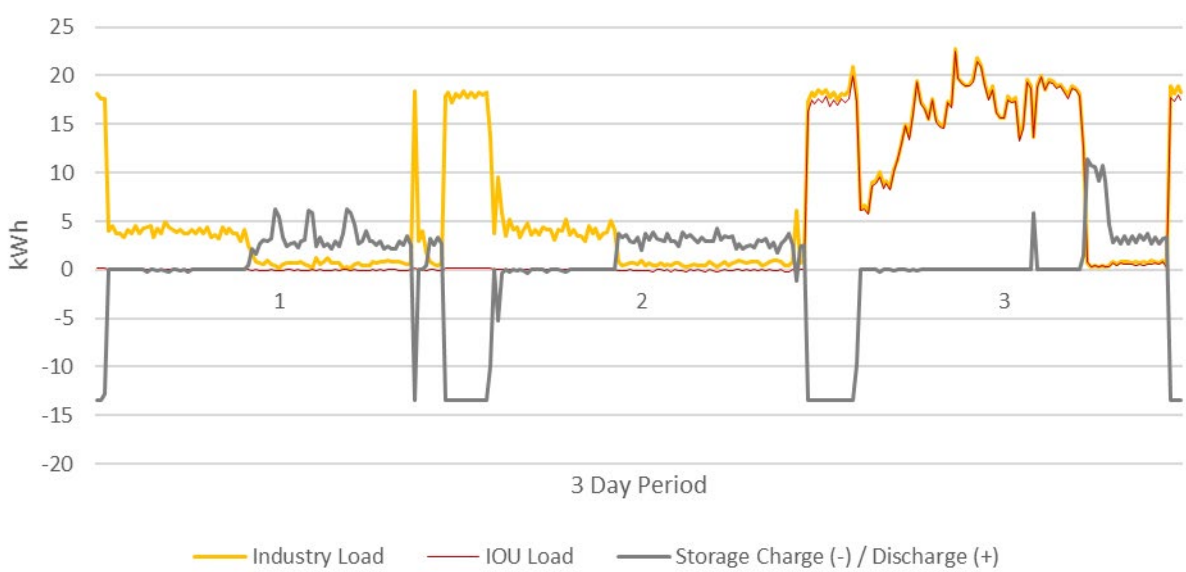
As discussed above, the storage analysis leveraged a variety of data sources including project developers, Energy Solutions (for projects that received a PBI incentive), the electric utilities and Itron meters. We conducted an extensive data cleaning and quality control exercise to ascertain whether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

- Interval battery data from developers were verified against interval battery data from Itron meters.
- 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 battery data were provided by the project developer and the Itron meters, 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.
- 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. We removed those spikes from the analysis data set.

Figure B-1 conveys a visualization of the data cleaning process. This is a three-day example that was mocked up to represent one of the storage projects. The yellow line represents the load data that would have been provided by the project developer. The red line represents the IOU load and the gray line represents the storage dispatch behavior. This example illustrates a couple of data cleaning exercises we performed:

- We can confirm the sync between the battery and load data. When the battery is charging (-) the load increases on the same time stamp.
- The IOU load data in this representative example 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.

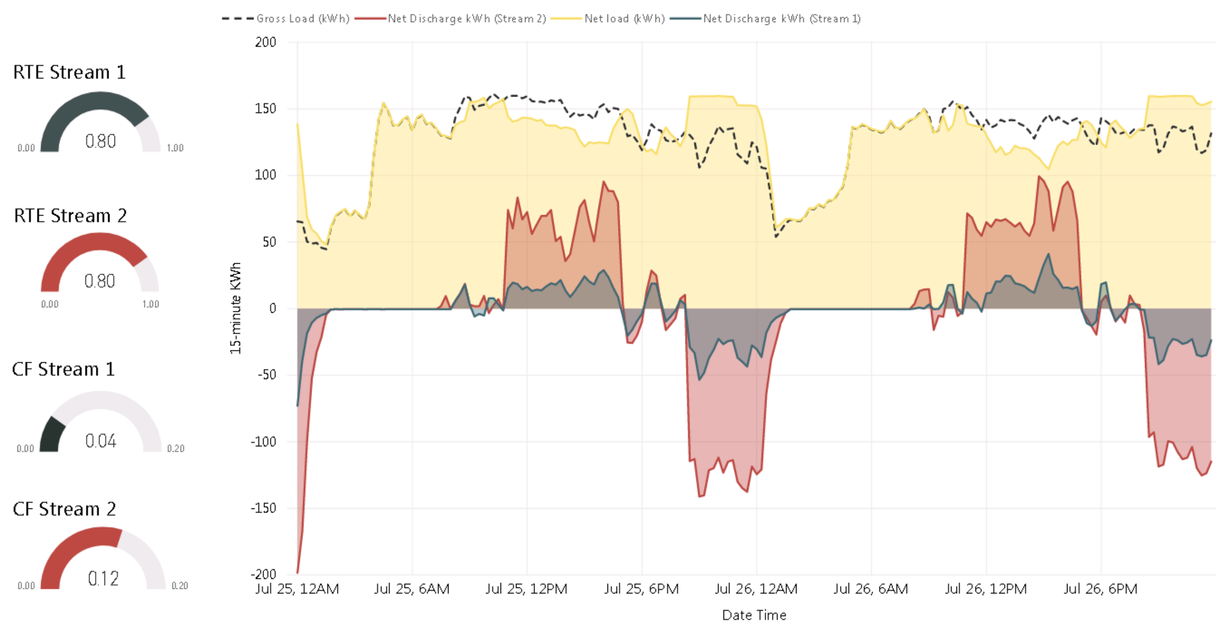
FIGURE B-1: EXAMPLE 1 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



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 4 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-2 illustrates this initial data cleaning step – where we compare the RTE and CF from two distinct data streams. While the RTE for both streams are identical (and with an expected range) the CF for both streams are both 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 kW per kW Rebated Capacity during CAISO Top 200 hours

FIGURE C-1: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI INDUSTRIAL)

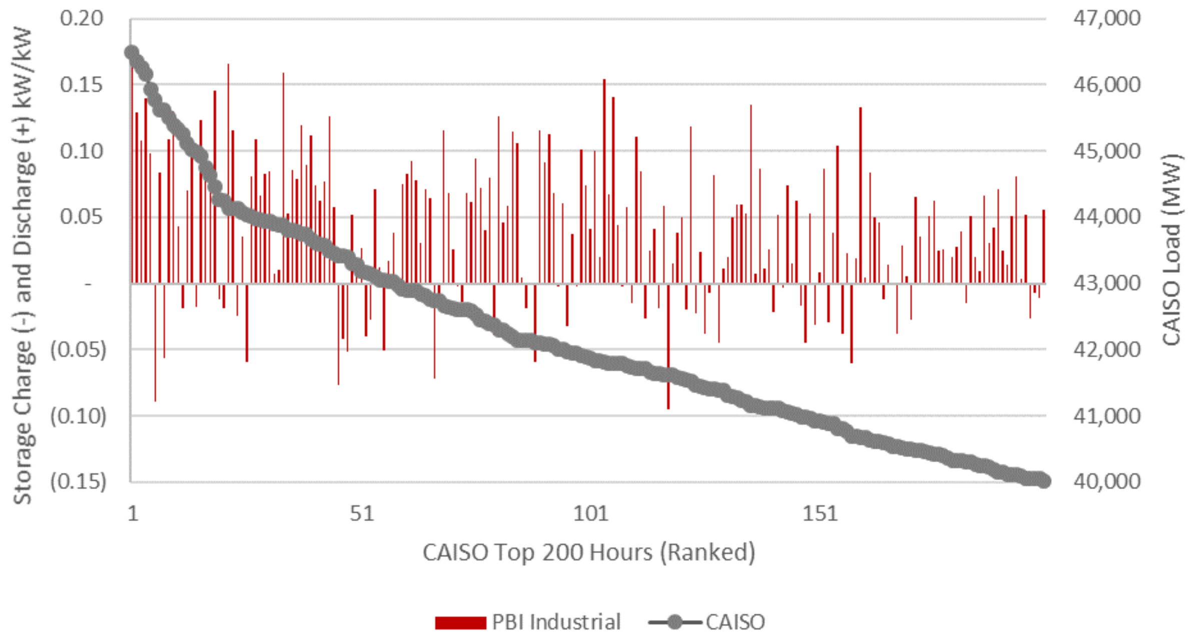


FIGURE C-2: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI OFFICE)

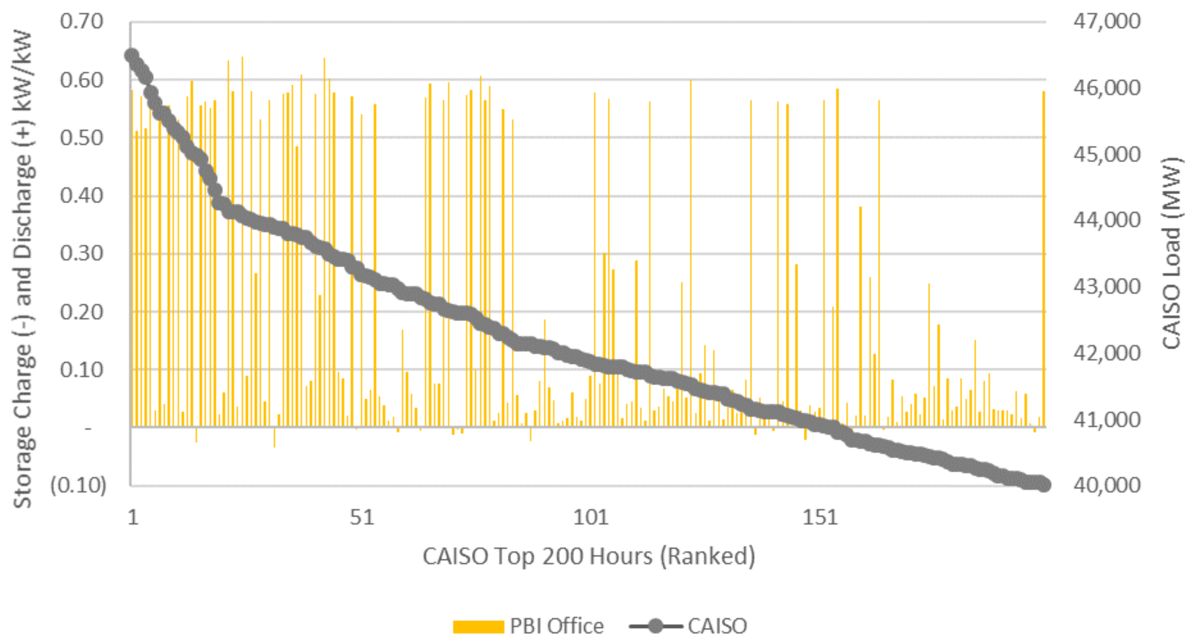


FIGURE C-3: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI OTHER)

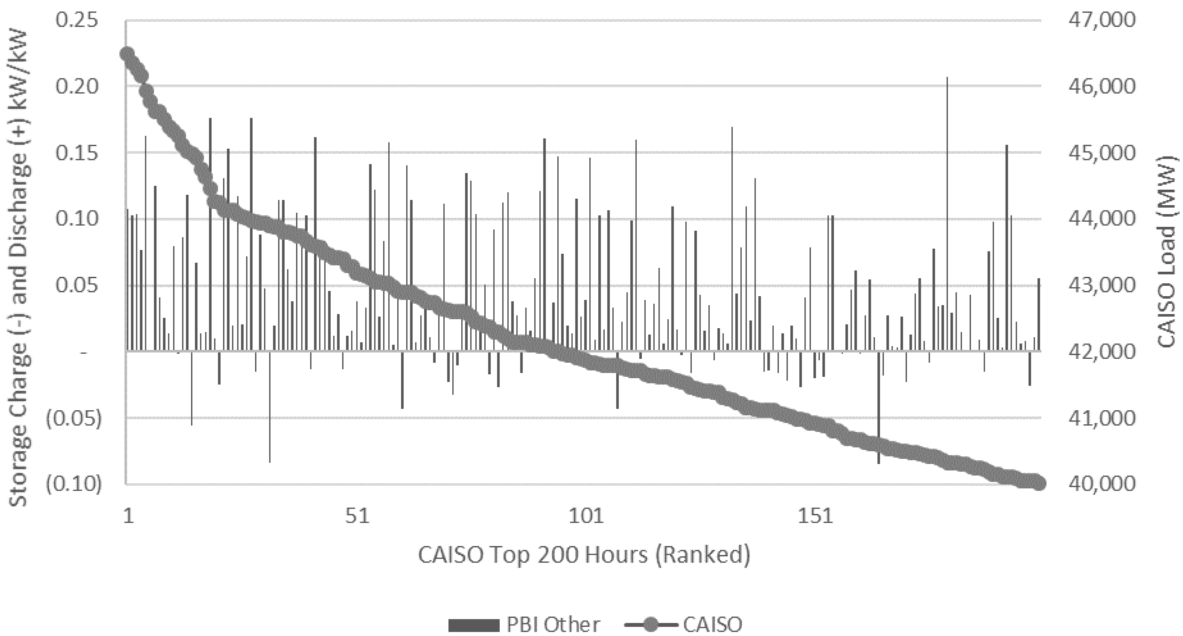


FIGURE C-4: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI RETAIL)

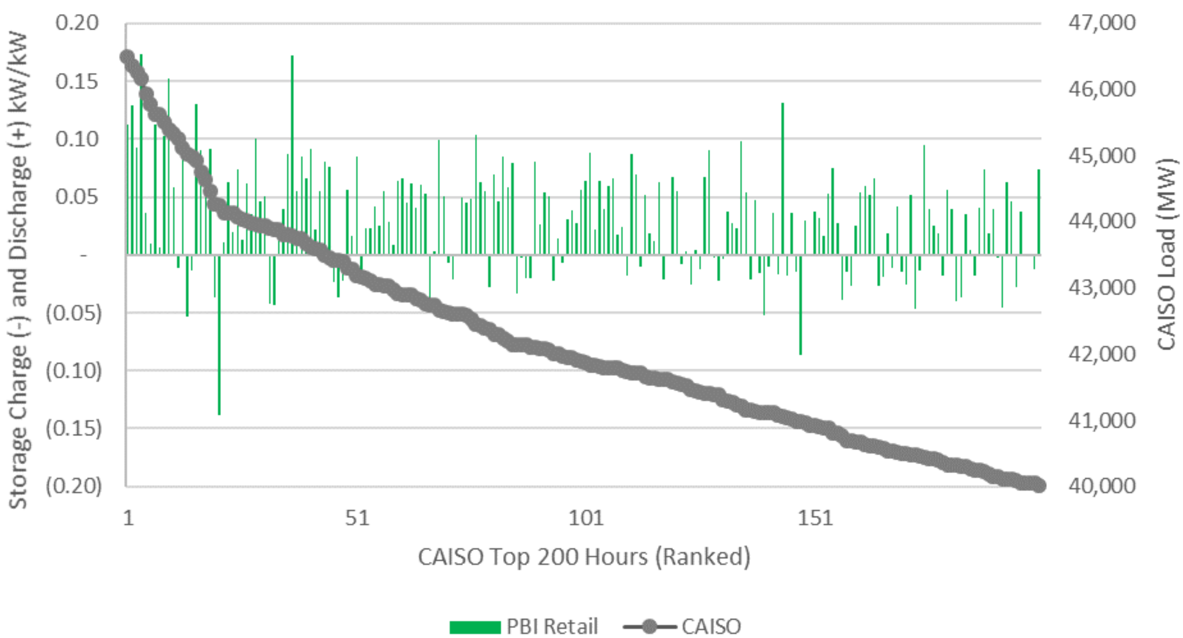


FIGURE C-5: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI SCHOOL)

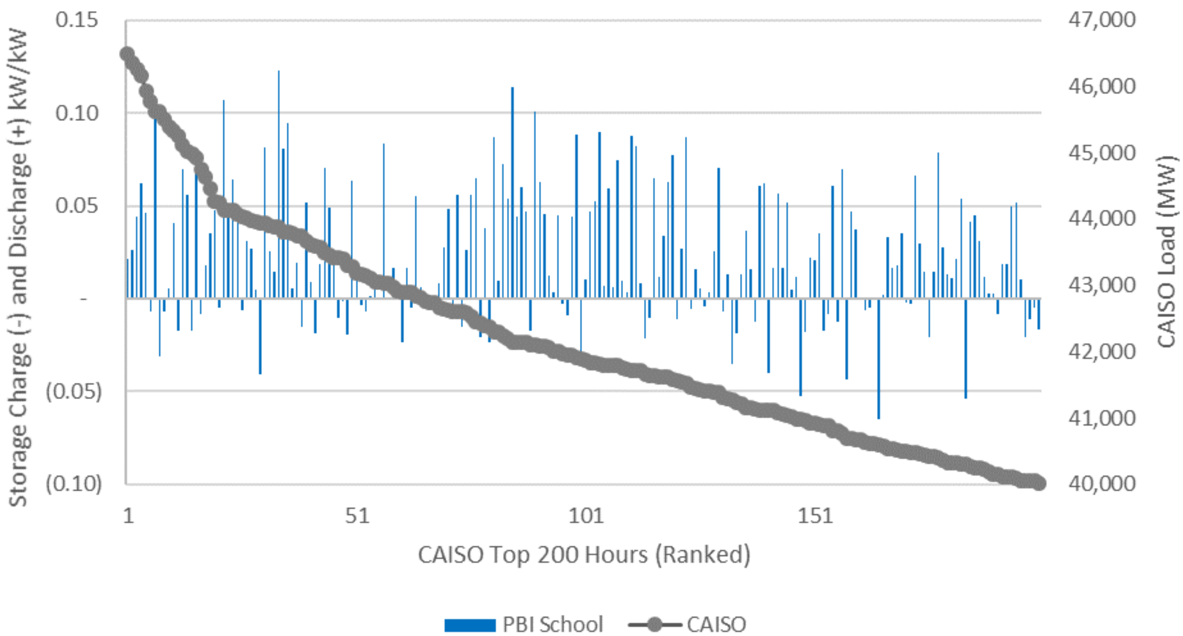


FIGURE C-6: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI INDUSTRIAL)

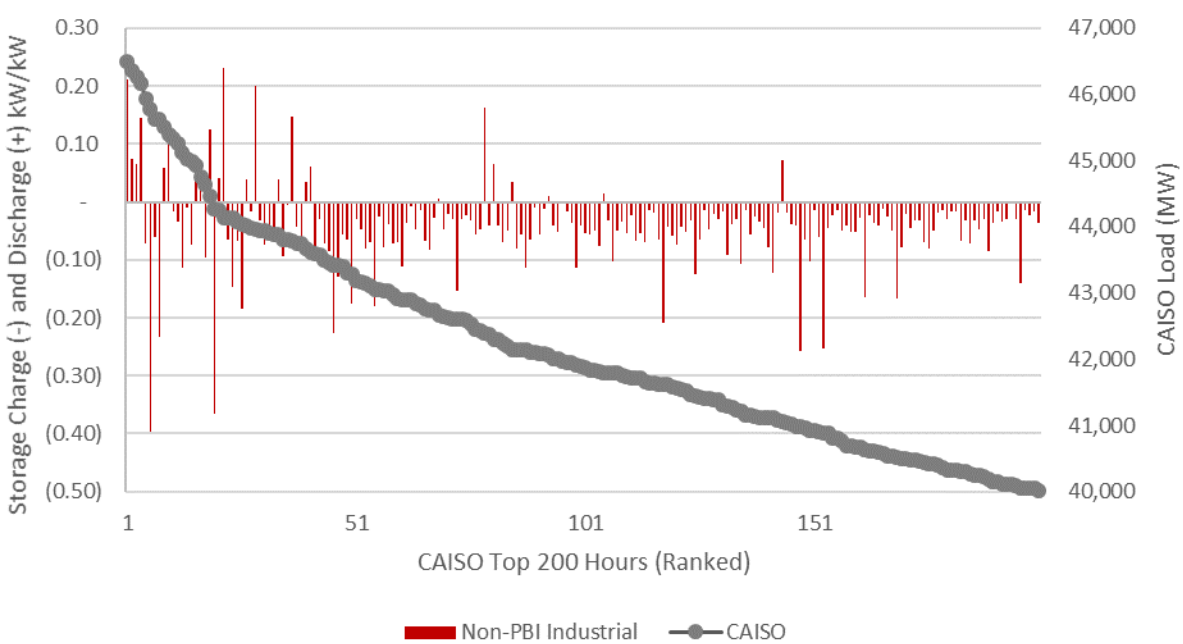


FIGURE C-7: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI OFFICE)

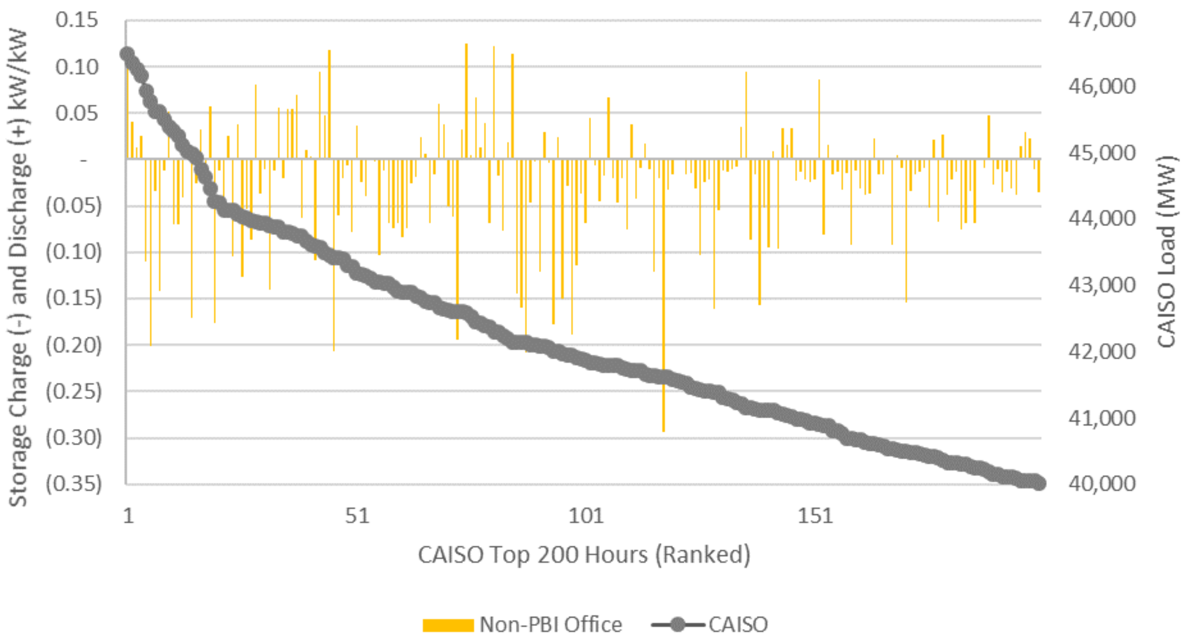


FIGURE C-8: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI OTHER)

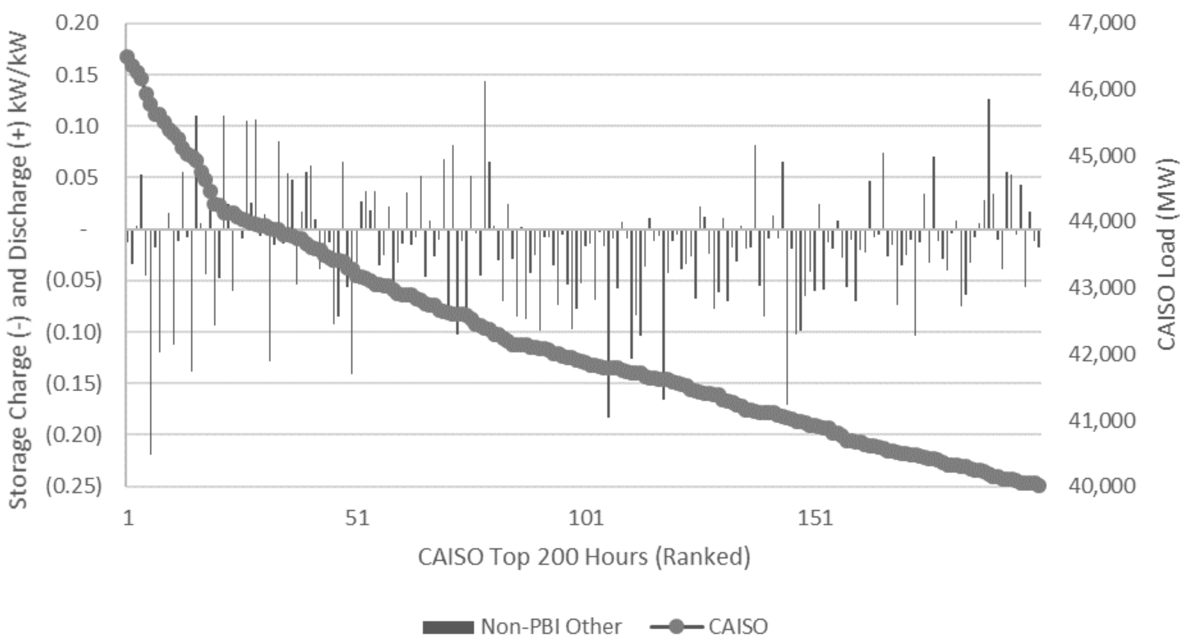


FIGURE C-9: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI RETAIL)

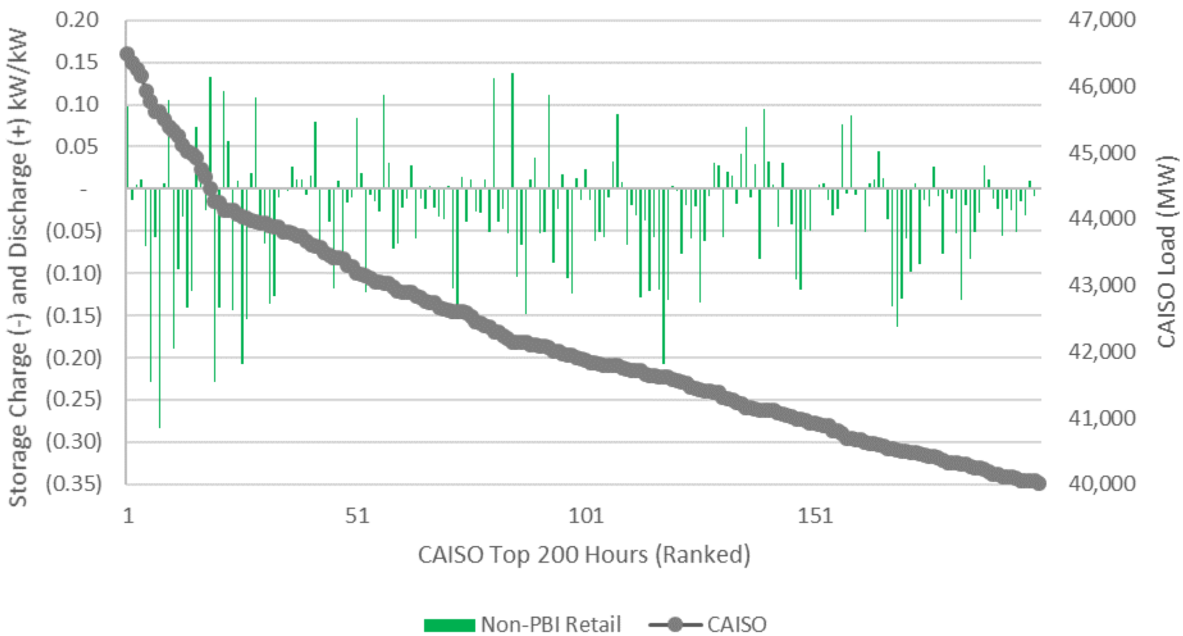


FIGURE C-10: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI FOOD/LIQUOR)

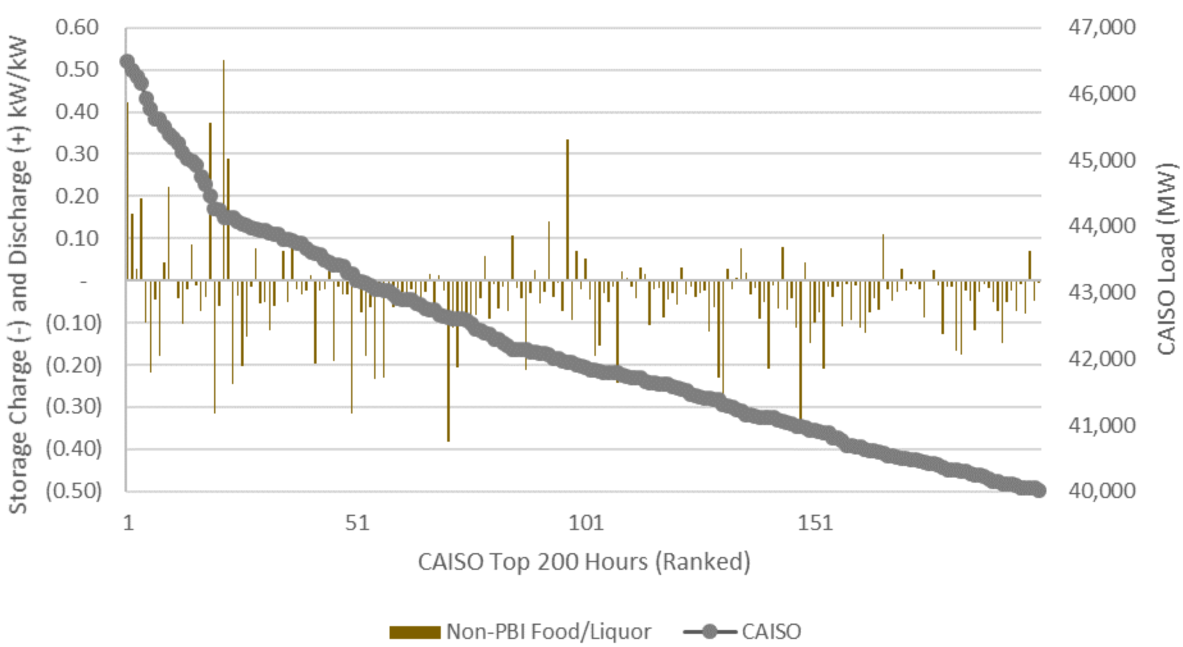
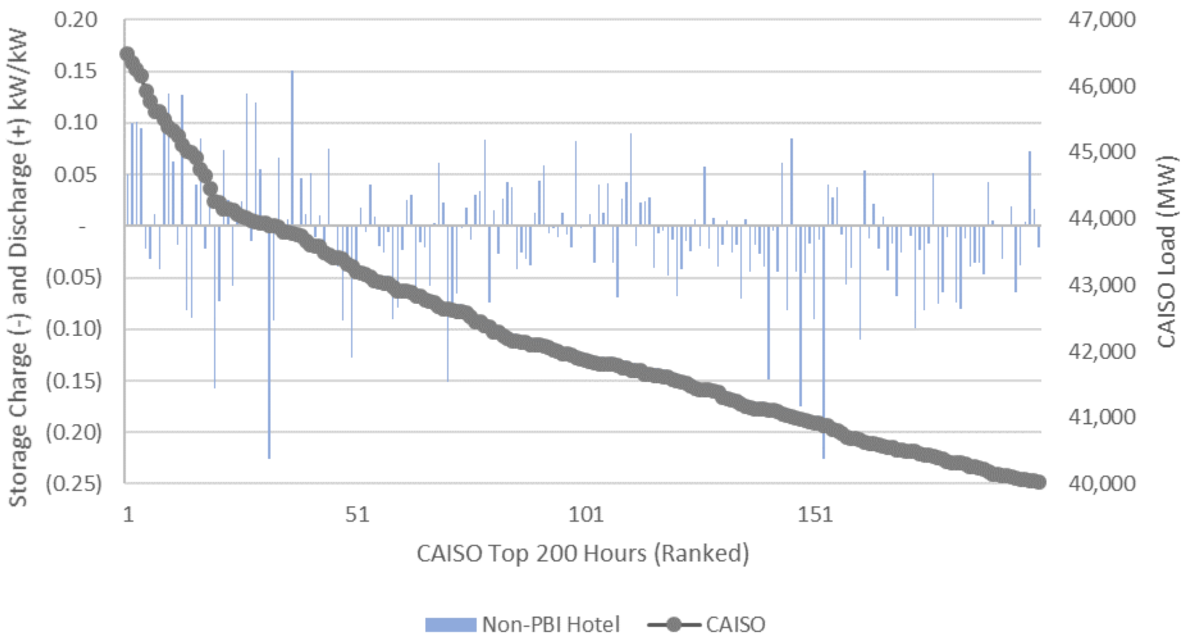


FIGURE C-11: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI HOTEL)



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

FIGURE C-12: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI INDUSTRIAL

	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
0	0.026	0.026	0.024	0.021	0.024	0.024	0.022	0.017	0.013	0.044	0.063	0.066	0
1	0.024	0.024	0.024	0.020	0.023	0.027	0.029	0.029	0.022	0.034	0.059	0.085	1
2	0.022	0.023	0.041	0.042	0.039	0.037	0.059	0.053	0.046	0.050	0.066	0.088	2
3	0.035	0.045	0.046	0.034	0.039	0.033	0.045	0.045	0.041	0.047	0.052	0.063	3
4	0.033	0.047	0.032	0.018	0.025	0.017	0.026	0.042	0.039	0.045	0.055	0.062	4
5	0.011	0.020	0.022	0.017	0.022	0.018	0.027	0.045	0.039	0.052	0.051	0.058	5
6	0.012	0.021	0.022	0.023	0.020	0.022	0.030	0.037	0.037	0.057	0.060	0.067	6
7	0.017	0.027	0.032	0.049	0.027	0.017	0.029	0.028	0.028	0.030	0.057	0.056	7
8	0.019	0.023	0.027	0.033	0.039	0.030	0.042	0.041	0.038	0.037	0.037	0.038	8
9	0.040	0.043	0.046	0.055	0.035	0.029	0.038	0.039	0.037	0.036	0.048	0.052	9
10	0.036	0.047	0.042	0.044	0.032	0.033	0.039	0.039	0.040	0.033	0.040	0.040	10
11	0.042	0.044	0.045	0.046	0.044	0.053	0.072	0.068	0.069	0.070	0.038	0.038	11
12	0.042	0.048	0.049	0.047	0.042	0.051	0.068	0.062	0.058	0.062	0.040	0.041	12
13	0.047	0.051	0.053	0.044	0.044	0.046	0.068	0.066	0.056	0.051	0.040	0.040	13
14	0.045	0.042	0.057	0.040	0.047	0.051	0.076	0.075	0.061	0.051	0.037	0.037	14
15	0.045	0.044	0.050	0.039	0.052	0.063	0.084	0.076	0.068	0.057	0.037	0.035	15
16	0.043	0.047	0.058	0.053	0.055	0.060	0.101	0.086	0.079	0.063	0.043	0.036	16
17	0.056	0.068	0.070	0.064	0.045	0.035	0.051	0.042	0.054	0.048	0.042	0.038	17
18	0.084	0.080	0.090	0.086	0.064	0.061	0.070	0.054	0.058	0.063	0.040	0.041	18
19	0.102	0.090	0.090	0.090	0.065	0.061	0.073	0.056	0.057	0.063	0.052	0.051	19
20	0.093	0.093	0.070	0.059	0.026	0.032	0.034	0.025	0.031	0.044	0.066	0.066	20
21	0.039	0.045	0.032	0.021	0.038	0.050	0.052	0.031	0.025	0.050	0.051	0.073	21
22	0.033	0.034	0.039	0.045	0.043	0.043	0.055	0.052	0.039	0.048	0.068	0.062	22
23	0.047	0.043	0.029	0.021	0.028	0.026	0.030	0.022	0.014	0.035	0.062	0.062	23

	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	-0.177	-0.186	-0.163	-0.130	-0.105	-0.119	-0.152	-0.127	-0.086	-0.109	-0.107	-0.115
1	-0.147	-0.166	-0.134	-0.088	-0.068	-0.075	-0.101	-0.079	-0.059	-0.098	-0.114	-0.127
2	-0.115	-0.122	-0.096	-0.058	-0.052	-0.053	-0.071	-0.058	-0.051	-0.078	-0.106	-0.125
3	-0.082	-0.083	-0.072	-0.054	-0.055	-0.044	-0.069	-0.064	-0.058	-0.075	-0.107	-0.121
4	-0.062	-0.069	-0.053	-0.038	-0.037	-0.038	-0.070	-0.061	-0.060	-0.072	-0.085	-0.102
5	-0.043	-0.043	-0.038	-0.030	-0.030	-0.024	-0.036	-0.055	-0.057	-0.061	-0.075	-0.087
6	-0.029	-0.027	-0.029	-0.029	-0.029	-0.030	-0.040	-0.053	-0.061	-0.061	-0.055	-0.064
7	-0.022	-0.026	-0.029	-0.035	-0.025	-0.024	-0.030	-0.030	-0.044	-0.046	-0.056	-0.060
8	-0.013	-0.023	-0.023	-0.022	-0.040	-0.045	-0.045	-0.043	-0.055	-0.063	-0.042	-0.045
9	-0.020	-0.034	-0.036	-0.037	-0.043	-0.048	-0.049	-0.047	-0.060	-0.054	-0.054	-0.059
10	-0.027	-0.036	-0.042	-0.044	-0.045	-0.042	-0.051	-0.053	-0.061	-0.053	-0.050	-0.059
11	-0.030	-0.038	-0.039	-0.030	-0.036	-0.034	-0.038	-0.040	-0.048	-0.034	-0.052	-0.054
12	-0.028	-0.024	-0.029	-0.020	-0.031	-0.030	-0.037	-0.038	-0.041	-0.031	-0.041	-0.047
13	-0.021	-0.018	-0.027	-0.022	-0.025	-0.035	-0.039	-0.037	-0.041	-0.039	-0.041	-0.042
14	-0.016	-0.017	-0.023	-0.025	-0.024	-0.032	-0.037	-0.036	-0.039	-0.039	-0.042	-0.045
15	-0.017	-0.013	-0.022	-0.023	-0.025	-0.031	-0.038	-0.035	-0.035	-0.039	-0.041	-0.044
16	-0.019	-0.019	-0.023	-0.019	-0.024	-0.036	-0.032	-0.034	-0.033	-0.036	-0.042	-0.046
17	-0.018	-0.014	-0.020	-0.023	-0.031	-0.040	-0.049	-0.054	-0.047	-0.064	-0.042	-0.043
18	-0.016	-0.016	-0.014	-0.018	-0.019	-0.026	-0.038	-0.034	-0.036	-0.053	-0.058	-0.042
19	-0.013	-0.013	-0.012	-0.014	-0.015	-0.022	-0.031	-0.036	-0.035	-0.043	-0.056	-0.043
20	-0.011	-0.011	-0.053	-0.081	-0.042	-0.023	-0.044	-0.044	-0.041	-0.036	-0.049	-0.047
21	-0.033	-0.035	-0.077	-0.101	-0.121	-0.085	-0.113	-0.096	-0.079	-0.111	-0.043	-0.043
22	-0.153	-0.155	-0.137	-0.122	-0.097	-0.109	-0.143	-0.125	-0.088	-0.095	-0.100	-0.122
23	-0.137	-0.138	-0.161	-0.173	-0.130	-0.141	-0.183	-0.164	-0.119	-0.113	-0.100	-0.107

FIGURE C-13: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI OFFICE

	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	0.035	0.022	0.018	0.019	0.038	0.013	0.033	0.033	0.057	0.031	0.005	0.007	0	-0.259	-0.263	-0.258	-0.211	-0.250	-0.081	-0.330	-0.331	-0.212	-0.362	-0.577	-0.566
1	0.038	0.032	0.019	0.019	0.034	0.012	0.037	0.038	0.053	0.050	0.003	0.007	1	-0.243	-0.257	-0.208	-0.153	-0.178	-0.051	-0.268	-0.234	-0.147	-0.250	-0.465	-0.440
2	0.045	0.023	0.027	0.024	0.035	0.014	0.024	0.050	0.043	0.023	0.004	0.006	2	-0.209	-0.214	-0.138	-0.103	-0.131	-0.042	-0.220	-0.191	-0.140	-0.210	-0.360	-0.347
3	0.050	0.028	0.028	0.031	0.035	0.019	0.030	0.041	0.029	0.022	0.002	0.004	3	-0.151	-0.158	-0.070	-0.050	-0.071	-0.034	-0.149	-0.164	-0.120	-0.146	-0.263	-0.277
4	0.050	0.026	0.020	0.010	0.013	0.015	0.015	0.041	0.025	0.020	0.008	0.006	4	-0.081	-0.087	-0.032	-0.029	-0.045	-0.025	-0.102	-0.109	-0.074	-0.081	-0.171	-0.179
5	0.015	0.015	0.016	0.011	0.011	0.007	0.020	0.041	0.024	0.012	0.012	0.018	5	-0.050	-0.039	-0.020	-0.016	-0.017	-0.016	-0.047	-0.086	-0.044	-0.042	-0.101	-0.101
6	0.016	0.023	0.028	0.027	0.021	0.007	0.015	0.041	0.028	0.015	0.017	0.042	6	-0.032	-0.023	-0.013	-0.007	-0.009	-0.009	-0.008	-0.030	-0.010	-0.012	-0.045	-0.044
7	0.020	0.019	0.037	0.043	0.032	0.019	0.017	0.035	0.020	0.016	0.027	0.058	7	-0.015	-0.013	-0.011	-0.007	-0.007	-0.006	-0.009	-0.028	-0.011	-0.011	-0.005	-0.007
8	0.019	0.030	0.030	0.041	0.051	0.038	0.044	0.065	0.031	0.038	0.038	0.049	8	-0.009	-0.008	-0.012	-0.011	-0.009	-0.008	-0.009	-0.027	-0.010	-0.011	-0.005	-0.006
9	0.038	0.049	0.054	0.052	0.052	0.051	0.063	0.079	0.041	0.056	0.062	0.055	9	-0.022	-0.017	-0.014	-0.009	-0.010	-0.006	-0.007	-0.027	-0.010	-0.011	-0.009	-0.011
10	0.054	0.075	0.062	0.060	0.056	0.051	0.067	0.087	0.048	0.072	0.073	0.057	10	-0.019	-0.013	-0.015	-0.009	-0.011	-0.007	-0.006	-0.024	-0.007	-0.013	-0.007	-0.009
11	0.079	0.107	0.084	0.055	0.053	0.042	0.057	0.085	0.046	0.072	0.081	0.062	11	-0.018	-0.012	-0.014	-0.009	-0.013	-0.009	-0.006	-0.026	-0.006	-0.011	-0.006	-0.007
12	0.142	0.111	0.086	0.053	0.046	0.034	0.051	0.062	0.039	0.076	0.081	0.061	12	-0.015	-0.012	-0.019	-0.011	-0.015	-0.007	-0.005	-0.029	-0.011	-0.011	-0.007	-0.007
13	0.127	0.101	0.065	0.039	0.051	0.034	0.200	0.154	0.035	0.097	0.095	0.060	13	-0.019	-0.015	-0.022	-0.011	-0.010	-0.005	-0.005	-0.025	-0.009	-0.012	-0.010	-0.008
14	0.070	0.058	0.044	0.041	0.050	0.038	0.222	0.163	0.038	0.211	0.125	0.067	14	-0.082	-0.075	-0.047	-0.012	-0.016	-0.007	-0.006	-0.019	-0.013	-0.011	-0.010	-0.011
15	0.062	0.051	0.039	0.037	0.049	0.035	0.227	0.165	0.034	0.315	0.324	0.342	15	-0.066	-0.071	-0.046	-0.014	-0.016	-0.009	-0.006	-0.024	-0.019	-0.019	-0.011	-0.010
16	0.040	0.037	0.054	0.033	0.058	0.036	0.244	0.164	0.036	0.377	0.431	0.411	16	-0.036	-0.036	-0.033	-0.012	-0.019	-0.006	-0.007	-0.016	-0.018	-0.024	-0.012	-0.010
17	0.054	0.096	0.051	0.039	0.057	0.006	0.031	0.044	0.051	0.041	0.420	0.402	17	-0.031	-0.036	-0.038	-0.012	-0.017	-0.011	-0.008	-0.020	-0.012	-0.024	-0.016	-0.015
18	0.057	0.063	0.090	0.065	0.071	0.009	0.053	0.087	0.084	0.073	0.079	0.059	18	-0.030	-0.020	-0.022	-0.006	-0.010	-0.008	-0.008	-0.022	-0.012	-0.023	-0.014	-0.011
19	0.067	0.085	0.092	0.059	0.094	0.018	0.056	0.138	0.120	0.111	0.087	0.074	19	-0.014	-0.013	-0.010	-0.006	-0.008	-0.008	-0.010	-0.012	-0.012	-0.014	-0.012	-0.011
20	0.052	0.083	0.076	0.049	0.128	0.012	0.089	0.173	0.179	0.104	0.109	0.085	20	-0.014	-0.014	-0.011	-0.006	-0.008	-0.013	-0.007	-0.018	-0.009	-0.041	-0.012	-0.010
21	0.028	0.049	0.066	0.053	0.190	0.032	0.141	0.240	0.231	0.152	0.140	0.133	21	-0.011	-0.011	-0.018	-0.021	-0.028	-0.015	-0.008	-0.024	-0.008	-0.024	-0.024	-0.020
22	0.067	0.089	0.031	0.021	0.029	0.020	0.018	0.027	0.025	0.023	0.159	0.166	22	-0.046	-0.033	-0.201	-0.296	-0.422	-0.278	-0.494	-0.547	-0.414	-0.520	-0.073	-0.016
23	0.034	0.027	0.018	0.022	0.035	0.014	0.026	0.030	0.036	0.017	0.005	0.007	23	-0.269	-0.260	-0.269	-0.239	-0.368	-0.132	-0.432	-0.487	-0.387	-0.509	-0.606	-0.581

FIGURE C-14: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI OTHER

	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	0.044	0.046	0.044	0.044	0.044	0.026	0.059	0.046	0.028	0.047	0.027	0.060	0	-0.148	-0.165	-0.202	-0.201	-0.185	-0.200	-0.213	-0.195	-0.145	-0.145	-0.171	-0.149
1	0.048	0.049	0.044	0.043	0.044	0.098	0.104	0.076	0.033	0.047	0.029	0.064	1	-0.124	-0.133	-0.165	-0.155	-0.116	-0.062	-0.129	-0.084	-0.077	-0.086	-0.123	-0.140
2	0.040	0.045	0.048	0.045	0.046	0.066	0.087	0.073	0.037	0.046	0.027	0.076	2	-0.108	-0.110	-0.112	-0.098	-0.078	-0.105	-0.147	-0.102	-0.077	-0.085	-0.077	-0.122
3	0.041	0.047	0.045	0.046	0.044	0.076	0.092	0.073	0.035	0.042	0.028	0.075	3	-0.078	-0.086	-0.081	-0.072	-0.065	-0.074	-0.119	-0.104	-0.059	-0.080	-0.067	-0.114
4	0.043	0.045	0.017	0.003	0.002	0.006	0.004	0.048	0.014	0.045	0.026	0.066	4	-0.064	-0.073	-0.054	-0.045	-0.037	-0.107	-0.150	-0.122	-0.079	-0.069	-0.065	-0.112
5	0.007	0.007	0.003	0.004	0.003	0.006	0.006	0.046	0.024	0.046	0.026	0.056	5	-0.041	-0.045	-0.024	-0.012	-0.007	-0.034	-0.043	-0.072	-0.036	-0.048	-0.057	-0.103
6	0.008	0.003	0.001	0.004	0.004	0.005	0.005	0.045	0.019	0.038	0.026	0.059	6	-0.014	-0.010	-0.007	-0.010	-0.009	-0.014	-0.018	-0.070	-0.032	-0.066	-0.058	-0.097
7	0.014	0.005	0.001	0.010	0.005	0.014	0.015	0.024	0.011	0.019	0.018	0.051	7	-0.014	-0.008	-0.005	-0.008	-0.009	-0.009	-0.015	-0.053	-0.034	-0.059	-0.048	-0.096
8	0.014	0.006	0.001	0.009	0.007	0.019	0.022	0.014	0.022	0.013	0.012	0.030	8	-0.011	-0.004	-0.002	-0.007	-0.007	-0.011	-0.023	-0.032	-0.025	-0.053	-0.029	-0.073
9	0.015	0.007	0.002	0.013	0.007	0.022	0.021	0.010	0.018	0.014	0.016	0.028	9	-0.018	-0.005	-0.002	-0.011	-0.008	-0.011	-0.020	-0.020	-0.028	-0.035	-0.022	-0.060
10	0.011	0.008	0.004	0.014	0.009	0.024	0.019	0.018	0.015	0.022	0.017	0.024	10	-0.017	-0.005	-0.002	-0.013	-0.009	-0.014	-0.019	-0.020	-0.021	-0.028	-0.023	-0.041
11	0.015	0.019	0.005	0.018	0.022	0.026	0.044	0.040	0.033	0.021	0.020	0.028	11	-0.012	-0.007	-0.002	-0.012	-0.008	-0.015	-0.014	-0.014	-0.016	-0.024	-0.026	-0.035
12	0.012	0.012	0.005	0.013	0.021	0.027	0.043	0.042	0.034	0.022	0.017	0.021	12	-0.018	-0.007	-0.002	-0.018	-0.007	-0.014	-0.017	-0.016	-0.022	-0.027	-0.014	-0.037
13	0.013	0.013	0.006	0.010	0.025	0.033	0.055	0.050	0.034	0.024	0.021	0.023	13	-0.013	-0.006	-0.002	-0.014	-0.007	-0.022	-0.017	-0.023	-0.017	-0.030	-0.018	-0.031
14	0.011	0.012	0.008	0.011	0.022	0.038	0.061	0.065	0.050	0.015	0.037	0.032	14	-0.017	-0.005	-0.003	-0.014	-0.010	-0.023	-0.019	-0.017	-0.020	-0.029	-0.024	-0.039
15	0.012	0.008	0.010	0.008	0.028	0.069	0.098	0.117	0.123	0.016	0.057	0.057	15	-0.013	-0.006	-0.003	-0.014	-0.008	-0.015	-0.013	-0.015	-0.019	-0.031	-0.022	-0.036
16	0.007	0.011	0.021	0.013	0.034	0.087	0.124	0.169	0.152	0.023	0.057	0.071	16	-0.021	-0.005	-0.006	-0.010	-0.009	-0.021	-0.012	-0.012	-0.025	-0.036	-0.024	-0.037
17	0.019	0.017	0.065	0.068	0.034	0.034	0.025	0.044	0.042	0.067	0.081	0.063	17	-0.009	-0.005	-0.008	-0.012	-0.011	-0.030	-0.036	-0.054	-0.052	-0.042	-0.027	-0.040
18	0.035	0.046	0.140	0.196	0.142	0.067	0.060	0.073	0.072	0.210	0.050	0.043	18	-0.004	-0.005	-0.006	-0.008	-0.011	-0.024	-0.031	-0.061	-0.043	-0.040	-0.042	-0.038
19	0.102	0.106	0.167	0.195	0.154	0.076	0.065	0.082	0.072	0.259	0.180	0.170	19	-0.003	-0.007	-0.005	-0.007	-0.009	-0.019	-0.026	-0.062	-0.049	-0.034	-0.030	-0.043
20	0.098	0.103	0.110	0.097	0.045	0.048	0.047	0.071	0.052	0.057	0.219	0.219	20	-0.006	-0.008	-0.013	-0.045	-0.036	-0.018	-0.026	-0.070	-0.046	-0.064	-0.036	-0.044
21	0.034	0.039	0.050	0.043	0.049	0.110	0.172	0.098	0.072	0.055	0.045	0.067	21	-0.028	-0.033	-0.072	-0.109	-0.131	-0.131	-0.153	-0.145	-0.099	-0.126	-0.085	-0.111
22	0.057	0.054	0.074	0.064	0.064	0.094	0.128	0.082	0.036	0.059	0.021	0.044	22	-0.066	-0.086	-0.140	-0.180	-0.194	-0.276	-0.324	-0.286	-0.194	-0.178	-0.133	-0.153
23	0.070	0.063	0.048	0.043	0.043	0.051	0.063	0.051	0.030	0.024	0.041	0.068	23	-0.122	-0.133	-0.211	-0.231	-0.247	-0.263	-0.275	-0.245	-0.191	-0.188	-0.161	-0.157

FIGURE C-15: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI RETAIL

	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	0.001	0.000	0.001	0.001	0.000	0.001	0.004	0.000	0.004	0.007	0.002	0.003	0	-0.256	-0.251	-0.185	-0.167	-0.090	-0.056	-0.148	-0.139	-0.085	-0.072	-0.100	-0.099
1	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.000	0.004	0.012	0.002	0.015	1	-0.176	-0.184	-0.115	-0.075	-0.029	-0.026	-0.082	-0.061	-0.049	-0.050	-0.080	-0.082
2	0.000	0.000	0.018	0.023	0.000	0.000	0.046	0.039	0.044	0.011	0.001	0.013	2	-0.093	-0.100	-0.054	-0.031	-0.008	-0.011	-0.024	-0.021	-0.028	-0.042	-0.059	-0.065
3	0.011	0.026	0.031	0.023	0.000	0.000	0.040	0.038	0.031	0.013	0.003	0.014	3	-0.041	-0.046	-0.025	-0.015	-0.002	-0.003	-0.017	-0.013	-0.044	-0.035	-0.042	-0.058
4	0.010	0.033	0.030	0.018	0.000	0.000	0.026	0.024	0.028	0.013	0.002	0.020	4	-0.020	-0.017	-0.013	-0.013	-0.003	-0.007	-0.027	-0.027	-0.041	-0.029	-0.035	-0.049
5	0.006	0.029	0.021	0.011	0.000	0.002	0.017	0.021	0.023	0.014	0.006	0.019	5	-0.011	-0.009	-0.007	-0.010	-0.002	-0.006	-0.030	-0.029	-0.044	-0.018	-0.027	-0.041
6	0.005	0.019	0.011	0.006	0.001	0.003	0.019	0.020	0.020	0.014	0.005	0.017	6	-0.010	-0.007	-0.007	-0.009	-0.003	-0.005	-0.028	-0.029	-0.058	-0.027	-0.019	-0.031
7	0.002	0.012	0.034	0.039	0.016	0.009	0.027	0.024	0.026	0.007	0.006	0.022	7	-0.008	-0.005	-0.013	-0.014	-0.004	-0.003	-0.021	-0.021	-0.030	-0.031	-0.036	-0.025
8	0.026	0.024	0.029	0.027	0.018	0.013	0.026	0.019	0.025	0.008	0.005	0.010	8	-0.006	-0.004	-0.015	-0.025	-0.011	-0.008	-0.033	-0.033	-0.054	-0.078	-0.042	-0.036
9	0.038	0.036	0.041	0.031	0.016	0.006	0.026	0.023	0.033	0.008	0.006	0.015	9	-0.022	-0.027	-0.033	-0.051	-0.022	-0.015	-0.031	-0.029	-0.042	-0.081	-0.079	-0.064
10	0.046	0.031	0.053	0.040	0.018	0.008	0.031	0.029	0.036	0.011	0.010	0.012	10	-0.023	-0.038	-0.035	-0.061	-0.031	-0.016	-0.030	-0.027	-0.040	-0.070	-0.079	-0.060
11	0.049	0.043	0.042	0.040	0.035	0.013	0.071	0.071	0.061	0.019	0.018	0.015	11	-0.022	-0.040	-0.039	-0.056	-0.023	-0.013	-0.027	-0.021	-0.035	-0.050	-0.063	-0.042
12	0.048	0.048	0.031	0.036	0.029	0.018	0.076	0.073	0.063	0.024	0.022	0.018	12	-0.027	-0.037	-0.039	-0.047	-0.024	-0.011	-0.025	-0.029	-0.027	-0.035	-0.038	-0.023
13	0.050	0.049	0.037	0.037	0.046	0.022	0.078	0.076	0.071	0.038	0.024	0.023	13	-0.020	-0.029	-0.037	-0.035	-0.018	-0.010	-0.023	-0.029	-0.022	-0.025	-0.029	-0.016
14	0.042	0.056	0.045	0.046	0.077	0.064	0.084	0.086	0.081	0.058	0.038	0.036	14	-0.017	-0.018	-0.023	-0.021	-0.012	-0.008	-0.022	-0.024	-0.017	-0.017	-0.021	-0.015
15	0.051	0.076	0.055	0.075	0.135	0.079	0.091	0.096	0.094	0.073	0.060	0.039	15	-0.010	-0.013	-0.014	-0.015	-0.013	-0.009	-0.026	-0.020	-0.024	-0.011	-0.015	-0.008
16	0.050	0.087	0.073	0.076	0.147	0.084	0.085	0.082	0.089	0.119	0.093	0.065	16	-0.009	-0.011	-0.011	-0.010	-0.010	-0.008	-0.018	-0.019	-0.022	-0.010	-0.016	-0.004
17	0.048	0.063	0.091	0.104	0.034	0.023	0.030	0.020	0.037	0.087	0.113	0.070	17	-0.006	-0.006	-0.010	-0.010	-0.009	-0.005	-0.024	-0.029	-0.031	-0.013	-0.010	-0.003
18	0.066	0.058	0.127	0.171	0.043	0.032	0.021	0.024	0.034	0.080	0.100	0.062	18	-0.007	-0.006	-0.008	-0.007	-0.003	-0.004	-0.026	-0.023	-0.032	-0.008	-0.014	-0.004
19	0.140	0.117	0.136	0.174	0.047	0.033	0.019	0.015	0.031	0.067	0.095	0.059	19	-0.006	-0.007	-0.008	-0.009	-0.003	-0.002	-0.022	-0.028	-0.039	-0.010	-0.010	-0.008
20	0.184	0.155	0.097	0.090	0.031	0.019	0.015	0.021	0.031	0.038	0.074	0.047	20	-0.007	-0.006	-0.042	-0.076	-0.044	-0.027	-0.022	-0.019	-0.029	-0.020	-0.012	-0.008
21	0.070	0.064	0.022	0.018	0.000	0.002	0.026	0.031	0.028	0.019	0.037	0.033	21	-0.046	-0.046	-0.115	-0.160	-0.175	-0.103	-0.039	-0.029	-0.071	-0.070	-0.021	-0.014
22	0.016	0.004	0.015	0.025	0.007	0.006	0.013	0.017	0.022	0.007	0.022	0.030	22	-0.196	-0.205	-0.181	-0.194	-0.154	-0.087	-0.165	-0.159	-0.135	-0.094	-0.070	-0.064
23	0.025	0.017	0.003	0.002	0.001	0.000	0.001	0.000	0.005	0.008	0.007	0.015	23	-0.210	-0.192	-0.217	-0.244	-0.179	-0.103	-0.204	-0.194	-0.146	-0.103	-0.081	-0.076

FIGURE C-16: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI SCHOOL

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	0.011	0.015	0.013	0.014	0.010	0.010	0.022	0.016	0.013	0.008	0.010	0.009
1	0.013	0.019	0.013	0.010	0.007	0.009	0.025	0.018	0.013	0.007	0.014	0.013
2	0.012	0.014	0.012	0.010	0.006	0.009	0.038	0.028	0.016	0.012	0.012	0.010
3	0.012	0.013	0.012	0.010	0.006	0.011	0.060	0.041	0.025	0.018	0.017	0.012
4	0.012	0.012	0.004	0.015	0.023	0.023	0.092	0.080	0.048	0.039	0.028	0.018
5	0.002	0.002	0.009	0.026	0.056	0.049	0.131	0.134	0.085	0.074	0.050	0.030
6	0.016	0.022	0.029	0.035	0.070	0.043	0.087	0.135	0.122	0.120	0.080	0.052
7	0.067	0.047	0.022	0.023	0.051	0.032	0.040	0.084	0.081	0.075	0.081	0.080
8	0.030	0.017	0.011	0.003	0.019	0.001	0.007	0.030	0.030	0.026	0.027	0.030
9	0.015	0.007	0.008	0.005	0.011	0.002	0.009	0.016	0.011	0.011	0.013	0.013
10	0.008	0.003	0.006	0.008	0.012	0.002	0.013	0.013	0.006	0.008	0.009	0.011
11	0.010	0.002	0.005	0.013	0.013	0.008	0.013	0.015	0.008	0.008	0.009	0.009
12	0.010	0.001	0.005	0.015	0.015	0.008	0.011	0.022	0.016	0.016	0.012	0.009
13	0.008	0.003	0.006	0.017	0.011	0.009	0.010	0.022	0.020	0.020	0.016	0.008
14	0.006	0.004	0.007	0.010	0.005	0.008	0.011	0.019	0.012	0.011	0.019	0.008
15	0.006	0.005	0.011	0.008	0.003	0.006	0.009	0.011	0.011	0.012	0.026	0.008
16	0.009	0.008	0.016	0.010	0.005	0.005	0.008	0.019	0.018	0.028	0.042	0.021
17	0.027	0.017	0.020	0.010	0.003	0.005	0.009	0.022	0.019	0.039	0.052	0.039
18	0.028	0.024	0.022	0.019	0.020	0.022	0.068	0.055	0.021	0.035	0.061	0.068
19	0.028	0.021	0.041	0.021	0.051	0.047	0.107	0.057	0.013	0.031	0.054	0.071
20	0.043	0.036	0.034	0.014	0.015	0.028	0.054	0.029	0.005	0.036	0.052	0.077
21	0.019	0.015	0.017	0.013	0.011	0.015	0.024	0.041	0.005	0.062	0.052	0.075
22	0.021	0.017	0.021	0.016	0.010	0.014	0.020	0.060	0.004	0.077	0.031	0.052
23	0.027	0.023	0.014	0.010	0.007	0.012	0.021	0.012	0.009	0.005	0.056	0.080

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	-0.021	-0.021	-0.019	-0.020	-0.024	-0.032	-0.012	-0.024	-0.011	-0.016	-0.023	-0.012
1	-0.020	-0.019	-0.020	-0.019	-0.023	-0.015	-0.016	-0.019	-0.006	-0.016	-0.019	-0.014
2	-0.021	-0.019	-0.021	-0.019	-0.021	-0.014	-0.006	-0.023	-0.009	-0.008	-0.014	-0.008
3	-0.021	-0.021	-0.020	-0.019	-0.020	-0.013	-0.005	-0.016	-0.005	-0.006	-0.008	-0.008
4	-0.021	-0.023	-0.020	-0.014	-0.013	-0.022	-0.034	-0.021	-0.012	-0.006	-0.006	-0.007
5	-0.023	-0.024	-0.013	-0.008	-0.011	-0.013	-0.016	-0.023	-0.010	-0.005	-0.005	-0.007
6	-0.012	-0.014	-0.017	-0.019	-0.011	-0.028	-0.046	-0.037	-0.011	-0.014	-0.010	-0.005
7	-0.015	-0.024	-0.040	-0.040	-0.019	-0.037	-0.129	-0.085	-0.036	-0.063	-0.050	-0.021
8	-0.048	-0.050	-0.053	-0.039	-0.044	-0.046	-0.242	-0.177	-0.102	-0.152	-0.128	-0.103
9	-0.092	-0.052	-0.062	-0.050	-0.069	-0.042	-0.197	-0.185	-0.134	-0.200	-0.190	-0.204
10	-0.074	-0.060	-0.050	-0.053	-0.066	-0.041	-0.109	-0.142	-0.115	-0.191	-0.185	-0.218
11	-0.059	-0.048	-0.038	-0.043	-0.059	-0.036	-0.062	-0.088	-0.091	-0.110	-0.135	-0.179
12	-0.038	-0.029	-0.025	-0.038	-0.056	-0.035	-0.040	-0.057	-0.057	-0.043	-0.061	-0.099
13	-0.021	-0.018	-0.019	-0.037	-0.048	-0.036	-0.033	-0.064	-0.044	-0.034	-0.037	-0.056
14	-0.021	-0.017	-0.017	-0.036	-0.049	-0.036	-0.033	-0.066	-0.050	-0.040	-0.029	-0.034
15	-0.027	-0.021	-0.023	-0.041	-0.048	-0.025	-0.028	-0.056	-0.034	-0.026	-0.027	-0.023
16	-0.042	-0.021	-0.021	-0.036	-0.033	-0.016	-0.017	-0.028	-0.014	-0.012	-0.015	-0.013
17	-0.026	-0.010	-0.014	-0.024	-0.022	-0.019	-0.016	-0.026	-0.016	-0.010	-0.012	-0.008
18	-0.019	-0.010	-0.009	-0.013	-0.014	-0.017	-0.009	-0.021	-0.010	-0.010	-0.013	-0.009
19	-0.016	-0.008	-0.009	-0.012	-0.012	-0.011	-0.007	-0.018	-0.010	-0.013	-0.017	-0.010
20	-0.017	-0.009	-0.014	-0.015	-0.030	-0.012	-0.016	-0.024	-0.013	-0.013	-0.018	-0.009
21	-0.034	-0.025	-0.027	-0.022	-0.037	-0.038	-0.027	-0.020	-0.015	-0.013	-0.017	-0.011
22	-0.025	-0.028	-0.028	-0.030	-0.032	-0.036	-0.030	-0.014	-0.012	-0.010	-0.018	-0.012
23	-0.025	-0.023	-0.022	-0.027	-0.028	-0.019	-0.017	-0.042	-0.014	-0.034	-0.014	-0.010

FIGURE C-17: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI INDUSTRIAL

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	0.005	0.000	0.000	0.000	0.225	0.242	0.292	0.114	0.122	0.239	0.136	0.243
1	0.002	0.000	0.000	0.000	0.152	0.136	0.218	0.326	0.327	0.295	0.116	0.225
2	0.000	0.000	0.000	0.000	0.125	0.089	0.038	0.161	0.170	0.203	0.117	0.201
3	0.004	0.000	0.000	0.000	0.098	0.077	0.008	0.059	0.119	0.108	0.092	0.157
4	0.013	0.000	0.061	0.106	0.128	0.049	0.073	0.047	0.101	0.038	0.083	0.116
5	0.102	0.024	0.055	0.091	0.106	0.070	0.091	0.051	0.082	0.046	0.063	0.072
6	0.084	0.049	0.048	0.041	0.080	0.033	0.061	0.035	0.048	0.022	0.048	0.067
7	0.036	0.032	0.036	0.062	0.053	0.035	0.050	0.029	0.033	0.018	0.043	0.043
8	0.065	0.030	0.018	0.019	0.047	0.041	0.040	0.042	0.050	0.021	0.021	0.029
9	0.058	0.032	0.041	0.072	0.088	0.060	0.068	0.055	0.078	0.035	0.025	0.030
10	0.130	0.058	0.042	0.066	0.081	0.052	0.069	0.065	0.077	0.041	0.040	0.046
11	0.069	0.047	0.049	0.067	0.097	0.085	0.118	0.078	0.068	0.033	0.049	0.041
12	0.102	0.060	0.050	0.053	0.085	0.059	0.088	0.076	0.067	0.047	0.049	0.036
13	0.067	0.053	0.050	0.047	0.085	0.052	0.075	0.055	0.076	0.065	0.050	0.042
14	0.053	0.039	0.045	0.046	0.072	0.044	0.064	0.057	0.080	0.052	0.036	0.050
15	0.045	0.047	0.047	0.040	0.067	0.034	0.042	0.038	0.071	0.044	0.032	0.051
16	0.033	0.035	0.040	0.037	0.071	0.033	0.042	0.046	0.085	0.049	0.032	0.047
17	0.035	0.036	0.034	0.036	0.077	0.031	0.045	0.045	0.083	0.039	0.032	0.041
18	0.036	0.032	0.034	0.035	0.066	0.028	0.029	0.035	0.077	0.034	0.026	0.035
19	0.033	0.022	0.034	0.035	0.061	0.026	0.028	0.034	0.076	0.031	0.024	0.039
20	0.029	0.024	0.029	0.027	0.042	0.015	0.021	0.027	0.084	0.066	0.028	0.030
21	0.012	0.010	0.010	0.004	0.041	0.008	0.053	0.108	0.180	0.230	0.042	0.070
22	0.003	0.000	0.003	0.002	0.036	0.003	0.021	0.044	0.139	0.084	0.091	0.122
23	0.000	0.000	0.000	0.000	0.033	0.000	0.008	0.013	0.048	0.034	0.044	0.068

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	-0.031	-0.030	-0.028	-0.030	-0.163	-0.117	-0.118	-0.042	-0.098	-0.069	-0.110	-0.163
1	-0.032	-0.030	-0.029	-0.030	-0.222	-0.258	-0.308	-0.244	-0.267	-0.324	-0.122	-0.263
2	-0.033	-0.030	-0.029	-0.030	-0.207	-0.151	-0.285	-0.340	-0.293	-0.395	-0.164	-0.280
3	-0.035	-0.031	-0.031	-0.031	-0.178	-0.106	-0.073	-0.226	-0.234	-0.283	-0.183	-0.302
4	-0.037	-0.031	-0.037	-0.039	-0.152	-0.131	-0.055	-0.127	-0.222	-0.154	-0.129	-0.234
5	-0.046	-0.037	-0.063	-0.070	-0.164	-0.099	-0.080	-0.087	-0.140	-0.074	-0.122	-0.156
6	-0.079	-0.064	-0.105	-0.149	-0.171	-0.105	-0.117	-0.081	-0.124	-0.069	-0.115	-0.113
7	-0.156	-0.075	-0.088	-0.113	-0.087	-0.048	-0.071	-0.054	-0.074	-0.038	-0.093	-0.099
8	-0.068	-0.059	-0.057	-0.081	-0.128	-0.086	-0.132	-0.084	-0.090	-0.050	-0.057	-0.055
9	-0.141	-0.064	-0.064	-0.076	-0.124	-0.098	-0.104	-0.072	-0.086	-0.051	-0.059	-0.071
10	-0.118	-0.061	-0.077	-0.105	-0.144	-0.093	-0.102	-0.077	-0.099	-0.059	-0.067	-0.068
11	-0.171	-0.084	-0.098	-0.128	-0.151	-0.114	-0.140	-0.111	-0.122	-0.063	-0.071	-0.072
12	-0.158	-0.112	-0.103	-0.126	-0.139	-0.114	-0.167	-0.126	-0.112	-0.061	-0.071	-0.063
13	-0.170	-0.097	-0.093	-0.100	-0.124	-0.107	-0.153	-0.120	-0.108	-0.085	-0.079	-0.065
14	-0.117	-0.094	-0.087	-0.095	-0.131	-0.111	-0.121	-0.116	-0.130	-0.117	-0.081	-0.078
15	-0.098	-0.101	-0.088	-0.084	-0.118	-0.069	-0.121	-0.106	-0.124	-0.109	-0.085	-0.090
16	-0.075	-0.076	-0.088	-0.083	-0.118	-0.075	-0.082	-0.090	-0.126	-0.085	-0.083	-0.088
17	-0.076	-0.086	-0.076	-0.080	-0.127	-0.066	-0.091	-0.093	-0.136	-0.089	-0.071	-0.101
18	-0.079	-0.074	-0.078	-0.079	-0.117	-0.063	-0.080	-0.084	-0.133	-0.088	-0.076	-0.090
19	-0.073	-0.064	-0.075	-0.079	-0.113	-0.062	-0.067	-0.080	-0.127	-0.079	-0.066	-0.082
20	-0.071	-0.063	-0.071	-0.066	-0.069	-0.042	-0.047	-0.049	-0.089	-0.038	-0.060	-0.072
21	-0.038	-0.036	-0.033	-0.025	-0.083	-0.037	-0.064	-0.094	-0.188	-0.184	-0.048	-0.054
22	-0.035	-0.031	-0.035	-0.031	-0.077	-0.032	-0.067	-0.112	-0.230	-0.208	-0.109	-0.146
23	-0.031	-0.029	-0.029	-0.031	-0.075	-0.033	-0.058	-0.088	-0.179	-0.150	-0.101	-0.116

FIGURE C-18: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI OFFICE

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	0.010	0.002	0.007	0.007	0.085	0.062	0.161	0.064	0.051	0.215	0.081	0.203
1	0.007	0.008	0.003	0.006	0.064	0.016	0.076	0.202	0.194	0.205	0.050	0.140
2	0.004	0.002	0.002	0.000	0.069	0.002	0.009	0.069	0.092	0.154	0.009	0.085
3	0.004	0.002	0.003	0.002	0.075	0.003	0.002	0.026	0.087	0.083	0.005	0.090
4	0.005	0.001	0.002	0.003	0.067	0.004	0.009	0.010	0.029	0.052	0.000	0.060
5	0.018	0.007	0.015	0.010	0.062	0.013	0.022	0.017	0.015	0.002	0.001	0.069
6	0.036	0.045	0.022	0.013	0.076	0.019	0.031	0.036	0.010	0.009	0.006	0.017
7	0.033	0.017	0.010	0.004	0.046	0.010	0.033	0.040	0.031	0.010	0.019	0.012
8	0.008	0.007	0.005	0.007	0.062	0.024	0.028	0.054	0.067	0.039	0.018	0.017
9	0.013	0.007	0.008	0.009	0.063	0.022	0.030	0.030	0.057	0.047	0.028	0.044
10	0.007	0.004	0.007	0.011	0.049	0.025	0.028	0.023	0.071	0.019	0.012	0.024
11	0.011	0.005	0.008	0.010	0.063	0.023	0.028	0.026	0.053	0.016	0.009	0.021
12	0.016	0.012	0.012	0.003	0.057	0.012	0.021	0.015	0.039	0.014	0.018	0.014
13	0.020	0.006	0.017	0.006	0.058	0.015	0.019	0.013	0.023	0.020	0.010	0.013
14	0.037	0.011	0.020	0.011	0.053	0.027	0.026	0.018	0.028	0.028	0.014	0.019
15	0.030	0.017	0.040	0.020	0.053	0.023	0.037	0.020	0.060	0.048	0.011	0.017
16	0.024	0.012	0.016	0.011	0.071	0.037	0.064	0.040	0.100	0.051	0.035	0.011
17	0.011	0.026	0.020	0.011	0.065	0.015	0.017	0.033	0.059	0.031	0.032	0.023
18	0.013	0.014	0.019	0.015	0.066	0.035	0.017	0.028	0.049	0.027	0.026	0.030
19	0.015	0.012	0.007	0.007	0.049	0.021	0.021	0.029	0.046	0.023	0.012	0.031
20	0.010	0.003	0.015	0.006	0.031	0.005	0.007	0.010	0.040	0.062	0.025	0.023
21	0.004	0.002	0.001	0.008	0.045	0.007	0.115	0.019	0.062	0.043	0.010	0.019
22	0.005	0.004	0.004	0.004	0.037	0.006	0.014	0.004	0.028	0.005	0.005	0.006
23	0.006	0.008	0.007	0.003	0.033	0.002	0.008	0.008	0.016	0.000	0.001	0.001

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	-0.024	-0.029	-0.029	-0.021	-0.085	-0.022	-0.106	-0.025	-0.033	-0.018	-0.031	-0.050
1	-0.025	-0.025	-0.021	-0.021	-0.091	-0.083	-0.172	-0.186	-0.118	-0.266	-0.109	-0.253
2	-0.031	-0.021	-0.017	-0.021	-0.088	-0.020	-0.064	-0.183	-0.198	-0.269	-0.071	-0.175
3	-0.023	-0.017	-0.016	-0.015	-0.094	-0.012	-0.020	-0.091	-0.147	-0.200	-0.026	-0.116
4	-0.019	-0.017	-0.017	-0.018	-0.098	-0.015	-0.017	-0.032	-0.111	-0.140	-0.022	-0.122
5	-0.019	-0.016	-0.016	-0.021	-0.105	-0.018	-0.024	-0.023	-0.050	-0.052	-0.016	-0.097
6	-0.023	-0.022	-0.021	-0.028	-0.092	-0.023	-0.032	-0.030	-0.026	-0.017	-0.020	-0.092
7	-0.033	-0.044	-0.038	-0.028	-0.068	-0.022	-0.034	-0.039	-0.022	-0.017	-0.019	-0.029
8	-0.030	-0.036	-0.020	-0.014	-0.105	-0.027	-0.065	-0.071	-0.067	-0.031	-0.025	-0.021
9	-0.043	-0.030	-0.025	-0.022	-0.102	-0.025	-0.043	-0.067	-0.092	-0.070	-0.057	-0.051
10	-0.037	-0.022	-0.022	-0.025	-0.086	-0.028	-0.037	-0.046	-0.081	-0.072	-0.050	-0.073
11	-0.024	-0.018	-0.026	-0.028	-0.089	-0.047	-0.044	-0.053	-0.103	-0.031	-0.029	-0.052
12	-0.020	-0.017	-0.026	-0.026	-0.092	-0.033	-0.052	-0.049	-0.070	-0.028	-0.026	-0.039
13	-0.033	-0.024	-0.032	-0.019	-0.085	-0.030	-0.037	-0.041	-0.067	-0.029	-0.031	-0.033
14	-0.031	-0.024	-0.021	-0.019	-0.081	-0.022	-0.041	-0.032	-0.046	-0.032	-0.028	-0.030
15	-0.033	-0.022	-0.036	-0.031	-0.093	-0.023	-0.045	-0.038	-0.048	-0.043	-0.028	-0.036
16	-0.036	-0.034	-0.029	-0.034	-0.087	-0.031	-0.044	-0.056	-0.080	-0.070	-0.021	-0.026
17	-0.042	-0.033	-0.035	-0.035	-0.092	-0.058	-0.094	-0.063	-0.143	-0.087	-0.036	-0.032
18	-0.039	-0.050	-0.042	-0.032	-0.091	-0.037	-0.042	-0.042	-0.095	-0.063	-0.050	-0.051
19	-0.035	-0.033	-0.048	-0.029	-0.102	-0.055	-0.031	-0.045	-0.092	-0.064	-0.053	-0.049
20	-0.043	-0.033	-0.032	-0.025	-0.063	-0.028	-0.030	-0.034	-0.050	-0.033	-0.038	-0.058
21	-0.029	-0.016	-0.030	-0.018	-0.074	-0.042	-0.121	-0.055	-0.106	-0.152	-0.031	-0.028
22	-0.037	-0.016	-0.022	-0.026	-0.080	-0.039	-0.075	-0.043	-0.096	-0.046	-0.041	-0.051
23	-0.024	-0.016	-0.021	-0.018	-0.062	-0.022	-0.029	-0.020	-0.044	-0.014	-0.026	-0.019

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FIGURE C-19: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI OTHER

	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
0	0.000	0.000	0.020	0.022	0.054	0.041	0.044	0.020	0.019	0.018	0.002	0.005	0
1	0.018	0.016	0.007	0.004	0.014	0.034	0.146	0.244	0.169	0.075	0.075	0.110	1
2	0.000	0.000	0.000	0.001	0.000	0.000	0.042	0.118	0.096	0.093	0.088	0.096	2
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.069	0.073	0.019	0.092	0.076	3
4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.012	0.060	0.002	0.078	0.069	4
5	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.032	0.000	0.041	0.010	5
6	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.020	0.000	0.011	0.000	6
7	0.002	0.000	0.001	0.013	0.007	0.009	0.010	0.013	0.012	0.006	0.002	0.000	7
8	0.010	0.006	0.002	0.014	0.026	0.022	0.032	0.034	0.024	0.021	0.007	0.007	8
9	0.024	0.023	0.014	0.023	0.038	0.034	0.050	0.051	0.041	0.034	0.022	0.017	9
10	0.036	0.033	0.013	0.035	0.043	0.032	0.051	0.049	0.045	0.037	0.031	0.019	10
11	0.038	0.035	0.014	0.035	0.052	0.038	0.034	0.054	0.047	0.041	0.030	0.025	11
12	0.034	0.036	0.015	0.024	0.055	0.053	0.047	0.047	0.051	0.041	0.043	0.024	12
13	0.041	0.039	0.034	0.036	0.040	0.056	0.051	0.060	0.056	0.061	0.042	0.027	13
14	0.029	0.036	0.025	0.031	0.048	0.052	0.043	0.067	0.056	0.040	0.031	0.028	14
15	0.035	0.035	0.036	0.025	0.034	0.055	0.044	0.062	0.040	0.035	0.019	0.033	15
16	0.032	0.033	0.034	0.010	0.030	0.024	0.035	0.056	0.032	0.019	0.011	0.021	16
17	0.020	0.026	0.013	0.001	0.010	0.031	0.032	0.017	0.022	0.011	0.007	0.009	17
18	0.012	0.019	0.007	0.002	0.002	0.003	0.017	0.013	0.006	0.014	0.001	0.006	18
19	0.004	0.012	0.006	0.000	0.000	0.000	0.001	0.003	0.001	0.000	0.000	0.007	19
20	0.000	0.000	0.000	0.000	0.000	0.003	0.002	0.041	0.033	0.019	0.000	0.002	20
21	0.000	0.000	0.000	0.000	0.001	0.002	0.089	0.037	0.063	0.025	0.019	0.003	21
22	0.000	0.000	0.000	0.001	0.000	0.000	0.027	0.009	0.012	0.000	0.024	0.003	22
23	0.000	0.000	0.000	0.001	0.000	0.004	0.004	0.007	0.012	0.000	0.004	0.000	23

	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	-0.006	-0.005	-0.016	-0.023	-0.041	-0.028	-0.028	-0.031	-0.025	-0.019	-0.009	-0.017
1	-0.022	-0.020	-0.026	-0.016	-0.050	-0.080	-0.137	-0.099	-0.062	-0.012	-0.027	-0.060
2	-0.016	-0.014	-0.011	-0.006	-0.016	-0.016	-0.154	-0.251	-0.162	-0.105	-0.096	-0.104
3	-0.006	-0.005	-0.005	-0.008	-0.006	-0.006	-0.012	-0.166	-0.123	-0.104	-0.108	-0.118
4	-0.005	-0.005	-0.005	-0.008	-0.005	-0.006	-0.007	-0.065	-0.111	-0.036	-0.109	-0.111
5	-0.005	-0.005	-0.005	-0.008	-0.005	-0.006	-0.007	-0.018	-0.072	-0.009	-0.120	-0.094
6	-0.006	-0.005	-0.004	-0.009	-0.005	-0.006	-0.007	-0.006	-0.045	-0.005	-0.048	-0.014
7	-0.006	-0.005	-0.005	-0.018	-0.011	-0.012	-0.015	-0.020	-0.031	-0.010	-0.017	-0.009
8	-0.010	-0.011	-0.003	-0.019	-0.029	-0.028	-0.042	-0.045	-0.037	-0.031	-0.013	-0.013
9	-0.025	-0.028	-0.011	-0.035	-0.042	-0.037	-0.055	-0.067	-0.054	-0.043	-0.031	-0.022
10	-0.034	-0.036	-0.011	-0.039	-0.043	-0.041	-0.064	-0.067	-0.067	-0.059	-0.039	-0.035
11	-0.039	-0.045	-0.017	-0.040	-0.051	-0.051	-0.056	-0.074	-0.060	-0.058	-0.045	-0.037
12	-0.049	-0.059	-0.020	-0.048	-0.057	-0.054	-0.047	-0.077	-0.064	-0.059	-0.047	-0.041
13	-0.057	-0.054	-0.021	-0.044	-0.063	-0.052	-0.041	-0.062	-0.057	-0.063	-0.051	-0.034
14	-0.044	-0.053	-0.031	-0.046	-0.060	-0.071	-0.048	-0.069	-0.061	-0.066	-0.046	-0.037
15	-0.056	-0.052	-0.037	-0.039	-0.062	-0.058	-0.053	-0.062	-0.057	-0.053	-0.039	-0.037
16	-0.055	-0.043	-0.039	-0.033	-0.055	-0.098	-0.065	-0.085	-0.064	-0.031	-0.031	-0.036
17	-0.043	-0.025	-0.054	-0.010	-0.036	-0.035	-0.043	-0.044	-0.044	-0.011	-0.026	-0.012
18	-0.025	-0.025	-0.036	-0.008	-0.029	-0.051	-0.048	-0.056	-0.029	-0.016	-0.015	-0.012
19	-0.024	-0.026	-0.013	-0.007	-0.021	-0.019	-0.050	-0.033	-0.019	-0.038	-0.007	-0.015
20	-0.008	-0.031	-0.016	-0.006	-0.004	-0.004	-0.006	-0.006	-0.003	-0.004	-0.007	-0.019
21	-0.003	-0.004	-0.004	-0.004	-0.006	-0.013	-0.054	-0.116	-0.063	-0.064	-0.004	-0.011
22	-0.006	-0.006	-0.005	-0.006	-0.006	-0.009	-0.088	-0.030	-0.093	-0.019	-0.049	-0.021
23	-0.006	-0.005	-0.005	-0.006	-0.006	-0.006	-0.026	-0.025	-0.029	-0.005	-0.034	-0.015

FIGURE C-20: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI RETAIL

	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
0	0.000	0.000	0.000	0.000	0.000	0.736	0.847	0.000	0.000	0.209	0.032	0.221	0
1	0.000	0.000	0.000	0.000	0.000	0.128	0.345	0.103	0.479	0.090	0.011	0.180	1
2	0.000	0.000	0.062	0.000	0.000	0.000	0.000	0.032	0.143	0.007	0.000	0.061	2
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.000	0.000	0.042	3
4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.044	4
5	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.045	5
6	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.032	6
7	0.014	0.007	0.006	0.000	0.001	0.007	0.001	0.000	0.002	0.000	0.000	0.029	7
8	0.131	0.031	0.016	0.007	0.008	0.055	0.018	0.000	0.006	0.010	0.002	0.019	8
9	0.153	0.046	0.046	0.025	0.014	0.057	0.092	0.010	0.031	0.020	0.004	0.011	9
10	0.131	0.057	0.046	0.060	0.040	0.058	0.056	0.037	0.030	0.012	0.013	0.011	10
11	0.095	0.056	0.060	0.060	0.050	0.086	0.025	0.009	0.031	0.029	0.027	0.011	11
12	0.109	0.028	0.033	0.055	0.054	0.065	0.043	0.006	0.007	0.021	0.057	0.015	12
13	0.129	0.027	0.025	0.030	0.025	0.058	0.043	0.003	0.006	0.009	0.038	0.016	13
14	0.118	0.006	0.016	0.013	0.006	0.032	0.018	0.000	0.013	0.009	0.035	0.016	14
15	0.016	0.001	0.001	0.005	0.007	0.024	0.005	0.000	0.022	0.009	0.032	0.013	15
16	0.005	0.000	0.001	0.001	0.001	0.003	0.003	0.000	0.019	0.010	0.025	0.015	16
17	0.001	0.000	0.000	0.000	0.000	0.005	0.000	0.000	0.002	0.014	0.018	0.007	17
18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.003	0.007	0.006	18
19	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.005	0.005	19
20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.001	20
21	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.238	0.219	0.501	0.032	0.027	21
22	0.000	0.000	0.000	0.000	0.000	0.000	0.069	0.850	0.474	0.169	0.000	0.043	22
23	0.000	0.000	0.000	0.000	0.000	0.000	0.021	0.050	0.184	0.009	0.000	0.030	23

	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	-0.011	-0.010	-0.010	-0.010	-0.010	-0.390	-0.397	-0.012	-0.141	-0.059	-0.028	-0.127
1	-0.011	-0.011	-0.010	-0.009	-0.010	-0.738	-0.910	-0.033	-0.150	-0.288	-0.060	-0.253
2	-0.011	-0.010	-0.010	-0.009	-0.009	-0.010	-0.265	-0.123	-0.547	-0.107	-0.029	-0.240
3	-0.011	-0.010	-0.074	-0.009	-0.009	-0.011	-0.010	-0.044	-0.134	-0.017	-0.020	-0.073
4	-0.011	-0.011	-0.027	-0.009	-0.010	-0.010	-0.010	-0.010	-0.018	-0.015	-0.019	-0.072
5	-0.011	-0.011	-0.010	-0.009	-0.010	-0.010	-0.010	-0.010	-0.014	-0.015	-0.018	-0.067
6	-0.011	-0.011	-0.010	-0.009	-0.010	-0.010	-0.010	-0.010	-0.014	-0.015	-0.018	-0.075
7	-0.020	-0.015	-0.013	-0.010	-0.012	-0.013	-0.012	-0.010	-0.016	-0.015	-0.017	-0.055
8	-0.023	-0.012	-0.017	-0.015	-0.015	-0.013	-0.016	-0.011	-0.018	-0.015	-0.018	-0.051
9	-0.037	-0.025	-0.025	-0.020	-0.027	-0.028	-0.014	-0.015	-0.015	-0.017	-0.020	-0.044
10	-0.043	-0.024	-0.021	-0.021	-0.021	-0.032	-0.022	-0.022	-0.024	-0.019	-0.027	-0.030
11	-0.112	-0.027	-0.019	-0.033	-0.024	-0.070	-0.028	-0.056	-0.038	-0.028	-0.025	-0.029
12	-0.169	-0.046	-0.029	-0.037	-0.061	-0.107	-0.068	-0.021	-0.047	-0.042	-0.029	-0.024
13	-0.145	-0.079	-0.055	-0.078	-0.069	-0.111	-0.084	-0.015	-0.039	-0.050	-0.039	-0.028
14	-0.200	-0.110	-0.112	-0.134	-0.061	-0.070	-0.082	-0.010	-0.040	-0.021	-0.047	-0.032
15	-0.324	-0.085	-0.111	-0.061	-0.060	-0.069	-0.069	-0.010	-0.015	-0.017	-0.060	-0.047
16	-0.160	-0.014	-0.013	-0.012	-0.011	-0.096	-0.034	-0.010	-0.018	-0.016	-0.045	-0.033
17	-0.016	-0.011	-0.010	-0.010	-0.011	-0.046	-0.058	-0.010	-0.032	-0.017	-0.025	-0.029
18	-0.012	-0.011	-0.010	-0.011	-0.010	-0.036	-0.010	-0.010	-0.054	-0.042	-0.044	-0.024
19	-0.011	-0.010	-0.010	-0.010	-0.010	-0.010	-0.009	-0.010	-0.023	-0.043	-0.034	-0.022
20	-0.011	-0.010	-0.010	-0.009	-0.009	-0.010	-0.009	-0.010	-0.018	-0.022	-0.029	-0.023
21	-0.011	-0.010	-0.010	-0.010	-0.009	-0.010	-0.009	-0.166	-0.151	-0.356	-0.052	-0.019
22	-0.011	-0.011	-0.010	-0.009	-0.010	-0.010	-0.052	-0.814	-0.361	-0.436	-0.061	-0.051
23	-0.011	-0.010	-0.010	-0.009	-0.010	-0.010	-0.061	-0.528	-0.536	-0.122	-0.036	-0.070

FIGURE C-21: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI HOTEL

	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
0	0.019	0.011	0.002	0.001	0.081	0.272	0.194	0.105	0.081	0.033	0.028	0.100	0
1	0.013	0.007	0.001	0.001	0.016	0.055	0.057	0.035	0.081	0.099	0.110	0.127	1
2	0.012	0.005	0.001	0.000	0.005	0.004	0.005	0.005	0.027	0.015	0.048	0.104	2
3	0.011	0.006	0.001	0.001	0.001	0.001	0.001	0.000	0.013	0.009	0.045	0.060	3
4	0.010	0.008	0.004	0.001	0.001	0.001	0.001	0.000	0.004	0.008	0.033	0.058	4
5	0.015	0.012	0.007	0.003	0.003	0.003	0.004	0.002	0.005	0.008	0.013	0.025	5
6	0.028	0.025	0.008	0.006	0.009	0.013	0.009	0.012	0.011	0.014	0.012	0.014	6
7	0.028	0.024	0.006	0.009	0.011	0.014	0.010	0.017	0.017	0.017	0.018	0.024	7
8	0.026	0.016	0.004	0.010	0.027	0.023	0.022	0.034	0.041	0.044	0.019	0.020	8
9	0.039	0.028	0.005	0.022	0.045	0.043	0.044	0.042	0.056	0.042	0.043	0.037	9
10	0.035	0.027	0.004	0.028	0.045	0.047	0.048	0.045	0.051	0.040	0.038	0.049	10
11	0.042	0.034	0.006	0.027	0.043	0.052	0.048	0.029	0.045	0.044	0.043	0.045	11
12	0.034	0.030	0.006	0.022	0.045	0.049	0.045	0.028	0.042	0.044	0.040	0.039	12
13	0.034	0.035	0.009	0.026	0.047	0.062	0.059	0.033	0.047	0.052	0.041	0.031	13
14	0.036	0.036	0.011	0.040	0.057	0.073	0.069	0.045	0.051	0.054	0.042	0.035	14
15	0.041	0.041	0.015	0.046	0.069	0.081	0.080	0.064	0.095	0.054	0.041	0.035	15
16	0.047	0.039	0.020	0.047	0.086	0.088	0.084	0.051	0.070	0.046	0.038	0.044	16
17	0.077	0.046	0.022	0.042	0.058	0.068	0.076	0.047	0.054	0.038	0.049	0.067	17
18	0.084	0.072	0.038	0.027	0.041	0.047	0.044	0.032	0.037	0.077	0.059	0.059	18
19	0.072	0.076	0.038	0.026	0.037	0.032	0.024	0.022	0.030	0.037	0.084	0.086	19
20	0.060	0.059	0.027	0.017	0.015	0.018	0.009	0.023	0.024	0.016	0.056	0.061	20
21	0.029	0.034	0.014	0.006	0.008	0.016	0.121	0.113	0.153	0.172	0.024	0.029	21
22	0.026	0.031	0.011	0.003	0.003	0.009	0.051	0.027	0.075	0.055	0.048	0.070	22
23	0.014	0.017	0.005	0.002	0.001	0.005	0.004	0.009	0.020	0.034	0.013	0.023	23

	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	-0.068	-0.040	-0.028	-0.018	-0.037	-0.037	-0.063	-0.052	-0.046	-0.053	-0.063	-0.069
1	-0.057	-0.035	-0.018	-0.014	-0.065	-0.302	-0.167	-0.106	-0.107	-0.122	-0.085	-0.124
2	-0.039	-0.029	-0.013	-0.010	-0.037	-0.090	-0.106	-0.057	-0.100	-0.077	-0.117	-0.141
3	-0.035	-0.026	-0.011	-0.010	-0.025	-0.039	-0.031	-0.022	-0.071	-0.043	-0.085	-0.159
4	-0.031	-0.024	-0.010	-0.010	-0.016	-0.021	-0.018	-0.013	-0.034	-0.028	-0.071	-0.124
5	-0.029	-0.023	-0.011	-0.013	-0.016	-0.017	-0.017	-0.013	-0.020	-0.023	-0.064	-0.110
6	-0.034	-0.028	-0.015	-0.014	-0.017	-0.022	-0.023	-0.018	-0.018	-0.026	-0.048	-0.060
7	-0.046	-0.040	-0.014	-0.019	-0.016	-0.021	-0.022	-0.016	-0.021	-0.025	-0.038	-0.042
8	-0.034	-0.034	-0.009	-0.017	-0.040	-0.040	-0.036	-0.036	-0.047	-0.054	-0.030	-0.035
9	-0.064	-0.049	-0.015	-0.026	-0.050	-0.051	-0.043	-0.045	-0.058	-0.055	-0.051	-0.058
10	-0.064	-0.046	-0.012	-0.039	-0.065	-0.066	-0.065	-0.063	-0.071	-0.064	-0.067	-0.063
11	-0.078	-0.050	-0.011	-0.040	-0.060	-0.071	-0.066	-0.065	-0.068	-0.064	-0.067	-0.066
12	-0.062	-0.050	-0.011	-0.041	-0.061	-0.075	-0.066	-0.065	-0.070	-0.062	-0.055	-0.058
13	-0.059	-0.047	-0.010	-0.038	-0.067	-0.075	-0.063	-0.055	-0.075	-0.069	-0.055	-0.056
14	-0.067	-0.051	-0.012	-0.036	-0.064	-0.076	-0.061	-0.054	-0.072	-0.078	-0.058	-0.052
15	-0.067	-0.051	-0.014	-0.046	-0.064	-0.073	-0.062	-0.054	-0.065	-0.077	-0.064	-0.054
16	-0.067	-0.059	-0.017	-0.049	-0.071	-0.082	-0.069	-0.054	-0.068	-0.074	-0.062	-0.058
17	-0.062	-0.062	-0.022	-0.053	-0.093	-0.092	-0.084	-0.080	-0.086	-0.069	-0.061	-0.058
18	-0.066	-0.068	-0.026	-0.055	-0.091	-0.100	-0.106	-0.085	-0.088	-0.057	-0.060	-0.073
19	-0.064	-0.062	-0.031	-0.043	-0.072	-0.084	-0.092	-0.063	-0.079	-0.054	-0.054	-0.077
20	-0.065	-0.069	-0.036	-0.048	-0.051	-0.057	-0.067	-0.029	-0.054	-0.042	-0.056	-0.075
21	-0.046	-0.054	-0.028	-0.030	-0.061	-0.072	-0.176	-0.133	-0.118	-0.134	-0.052	-0.059
22	-0.078	-0.080	-0.037	-0.033	-0.046	-0.050	-0.144	-0.089	-0.175	-0.132	-0.088	-0.106
23	-0.072	-0.066	-0.032	-0.023	-0.027	-0.035	-0.038	-0.044	-0.118	-0.134	-0.069	-0.076

FIGURE C-22: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI FOOD/LIQUOR

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	Hour
0	0.011	0.001	0.007	0.010	0.011	0.012	0.017	0.012	0.025	0.068	0.045	0.069	0
1	0.015	0.010	0.004	0.000	0.000	0.000	0.192	0.157	0.091	0.002	0.029	0.143	1
2	0.002	0.000	0.000	0.000	0.000	0.001	0.034	0.064	0.044	0.090	0.079	0.173	2
3	0.004	0.000	0.000	0.000	0.000	0.001	0.007	0.049	0.018	0.022	0.011	0.074	3
4	0.008	0.000	0.000	0.003	0.002	0.005	0.008	0.038	0.004	0.023	0.001	0.025	4
5	0.040	0.011	0.002	0.011	0.019	0.010	0.016	0.018	0.004	0.014	0.023	0.048	5
6	0.052	0.020	0.000	0.002	0.006	0.005	0.008	0.018	0.002	0.015	0.020	0.056	6
7	0.011	0.009	0.004	0.003	0.001	0.009	0.006	0.008	0.001	0.006	0.008	0.038	7
8	0.008	0.002	0.009	0.002	0.002	0.013	0.031	0.018	0.002	0.011	0.007	0.033	8
9	0.011	0.003	0.014	0.004	0.015	0.021	0.059	0.031	0.006	0.012	0.008	0.029	9
10	0.013	0.005	0.017	0.015	0.021	0.067	0.097	0.031	0.023	0.016	0.019	0.028	10
11	0.047	0.027	0.012	0.014	0.022	0.046	0.065	0.035	0.032	0.027	0.014	0.051	11
12	0.039	0.021	0.006	0.011	0.034	0.083	0.065	0.040	0.046	0.032	0.013	0.034	12
13	0.042	0.027	0.007	0.010	0.029	0.053	0.041	0.027	0.054	0.039	0.025	0.025	13
14	0.044	0.022	0.004	0.007	0.037	0.040	0.068	0.044	0.060	0.024	0.013	0.029	14
15	0.039	0.025	0.001	0.007	0.027	0.038	0.034	0.028	0.049	0.017	0.014	0.021	15
16	0.046	0.026	0.003	0.013	0.018	0.038	0.042	0.044	0.012	0.012	0.016	0.028	16
17	0.064	0.024	0.006	0.007	0.008	0.062	0.036	0.019	0.024	0.009	0.024	0.051	17
18	0.040	0.008	0.000	0.004	0.008	0.041	0.021	0.021	0.018	0.009	0.013	0.038	18
19	0.027	0.012	0.001	0.001	0.000	0.005	0.007	0.005	0.004	0.005	0.005	0.033	19
20	0.006	0.002	0.000	0.000	0.001	0.000	0.008	0.003	0.008	0.069	0.001	0.021	20
21	0.001	0.001	0.000	0.000	0.001	0.000	0.079	0.031	0.076	0.259	0.029	0.048	21
22	0.001	0.000	0.000	0.000	0.000	0.000	0.127	0.101	0.093	0.168	0.099	0.252	22
23	0.006	0.002	0.000	0.000	0.000	0.005	0.035	0.036	0.046	0.139	0.064	0.143	23

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	-0.018	-0.014	-0.007	-0.017	-0.022	-0.026	-0.047	-0.045	-0.062	-0.251	-0.097	-0.235
1	-0.024	-0.019	-0.009	-0.014	-0.019	-0.023	-0.099	-0.086	-0.087	-0.061	-0.079	-0.086
2	-0.024	-0.016	-0.003	-0.006	-0.010	-0.015	-0.161	-0.132	-0.074	-0.044	-0.095	-0.270
3	-0.015	-0.010	0.000	-0.006	-0.010	-0.015	-0.062	-0.082	-0.054	-0.087	-0.065	-0.189
4	-0.014	-0.008	0.000	-0.007	-0.012	-0.016	-0.024	-0.077	-0.026	-0.051	-0.022	-0.083
5	-0.018	-0.008	0.000	-0.015	-0.015	-0.017	-0.017	-0.056	-0.008	-0.033	-0.011	-0.048
6	-0.026	-0.010	-0.002	-0.011	-0.029	-0.017	-0.035	-0.036	-0.013	-0.029	-0.014	-0.056
7	-0.066	-0.027	-0.002	-0.009	-0.016	-0.018	-0.018	-0.026	-0.006	-0.021	-0.019	-0.055
8	-0.040	-0.017	-0.003	-0.007	-0.009	-0.016	-0.016	-0.015	-0.007	-0.018	-0.020	-0.042
9	-0.038	-0.016	-0.005	-0.009	-0.014	-0.024	-0.018	-0.016	-0.014	-0.025	-0.017	-0.044
10	-0.026	-0.014	-0.011	-0.012	-0.024	-0.028	-0.030	-0.033	-0.019	-0.021	-0.018	-0.044
11	-0.026	-0.014	-0.013	-0.014	-0.030	-0.059	-0.049	-0.033	-0.022	-0.027	-0.028	-0.052
12	-0.044	-0.019	-0.024	-0.013	-0.032	-0.030	-0.040	-0.022	-0.024	-0.025	-0.028	-0.047
13	-0.043	-0.017	-0.014	-0.013	-0.036	-0.057	-0.064	-0.047	-0.032	-0.036	-0.029	-0.052
14	-0.048	-0.026	-0.005	-0.011	-0.033	-0.052	-0.044	-0.032	-0.028	-0.046	-0.032	-0.042
15	-0.062	-0.031	-0.005	-0.016	-0.037	-0.078	-0.077	-0.056	-0.055	-0.047	-0.028	-0.050
16	-0.060	-0.046	-0.009	-0.022	-0.055	-0.084	-0.078	-0.039	-0.076	-0.035	-0.032	-0.044
17	-0.068	-0.035	-0.010	-0.022	-0.046	-0.070	-0.083	-0.039	-0.057	-0.037	-0.034	-0.045
18	-0.066	-0.045	-0.008	-0.027	-0.032	-0.073	-0.075	-0.036	-0.057	-0.030	-0.034	-0.051
19	-0.063	-0.027	-0.001	-0.010	-0.022	-0.107	-0.106	-0.058	-0.047	-0.030	-0.032	-0.055
20	-0.068	-0.028	-0.001	-0.008	-0.013	-0.056	-0.071	-0.047	-0.021	-0.040	-0.032	-0.076
21	-0.046	-0.016	0.000	-0.006	-0.011	-0.026	-0.104	-0.076	-0.071	-0.172	-0.035	-0.052
22	-0.028	-0.021	0.000	-0.006	-0.011	-0.017	-0.191	-0.093	-0.092	-0.280	-0.084	-0.175
23	-0.016	-0.012	0.000	-0.006	-0.011	-0.015	-0.115	-0.106	-0.110	-0.216	-0.135	-0.263

FIGURE C-23: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS ON A TIERED RATE

	Mean AES kWh/Rebated kW During Period												
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	Hour
0	0.007	0.018	0.021	0.024	0.029	0.036	0.020	0.032	0.031	0.030	0.025	0.017	0
1	0.005	0.013	0.019	0.022	0.027	0.033	0.020	0.026	0.028	0.025	0.019	0.011	1
2	0.005	0.012	0.017	0.022	0.025	0.031	0.017	0.022	0.024	0.023	0.016	0.009	2
3	0.005	0.010	0.017	0.022	0.023	0.029	0.016	0.019	0.022	0.022	0.014	0.008	3
4	0.004	0.009	0.017	0.023	0.025	0.030	0.015	0.018	0.021	0.021	0.013	0.007	4
5	0.004	0.008	0.019	0.029	0.026	0.029	0.014	0.016	0.020	0.021	0.013	0.006	5
6	0.006	0.008	0.015	0.019	0.018	0.019	0.012	0.012	0.016	0.016	0.013	0.007	6
7	0.005	0.008	0.007	0.006	0.008	0.006	0.009	0.007	0.007	0.006	0.007	0.005	7
8	0.003	0.003	0.003	0.003	0.005	0.004	0.006	0.004	0.005	0.004	0.004	0.002	8
9	0.002	0.003	0.002	0.002	0.004	0.002	0.004	0.005	0.003	0.004	0.004	0.003	9
10	0.002	0.003	0.003	0.003	0.003	0.002	0.005	0.006	0.004	0.005	0.005	0.006	10
11	0.106	0.111	0.089	0.089	0.086	0.073	0.073	0.039	0.032	0.028	0.027	0.031	11
12	0.105	0.114	0.090	0.088	0.087	0.072	0.075	0.041	0.035	0.030	0.030	0.033	12
13	0.021	0.017	0.021	0.019	0.019	0.028	0.027	0.022	0.016	0.018	0.015	0.014	13
14	0.020	0.006	0.006	0.004	0.005	0.016	0.020	0.033	0.039	0.041	0.029	0.028	14
15	0.027	0.008	0.008	0.006	0.006	0.010	0.025	0.057	0.063	0.062	0.059	0.063	15
16	0.044	0.021	0.017	0.017	0.015	0.025	0.058	0.101	0.112	0.128	0.111	0.111	16
17	0.048	0.051	0.043	0.037	0.037	0.048	0.083	0.135	0.151	0.149	0.121	0.131	17
18	0.050	0.069	0.058	0.061	0.061	0.062	0.085	0.143	0.152	0.124	0.103	0.105	18
19	0.041	0.057	0.059	0.062	0.071	0.069	0.080	0.126	0.127	0.101	0.082	0.076	19
20	0.031	0.052	0.051	0.054	0.060	0.065	0.073	0.095	0.095	0.080	0.068	0.062	20
21	0.023	0.041	0.041	0.043	0.048	0.060	0.058	0.070	0.068	0.061	0.053	0.044	21
22	0.014	0.031	0.030	0.032	0.038	0.045	0.036	0.052	0.050	0.046	0.040	0.031	22
23	0.010	0.023	0.024	0.026	0.030	0.045	0.025	0.046	0.044	0.043	0.030	0.019	23

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	-0.004	-0.004	-0.003	-0.003	-0.003	-0.008	-0.005	-0.001	-0.001	-0.001	-0.005	-0.005
1	-0.004	-0.004	-0.003	-0.003	-0.003	-0.002	-0.006	-0.005	-0.004	-0.004	-0.006	-0.005
2	-0.004	-0.004	-0.004	-0.004	-0.003	-0.003	-0.007	-0.005	-0.004	-0.004	-0.004	-0.004
3	-0.004	-0.004	-0.004	-0.003	-0.003	-0.003	-0.006	-0.005	-0.004	-0.004	-0.004	-0.004
4	-0.005	-0.004	-0.003	-0.003	-0.003	-0.003	-0.006	-0.004	-0.003	-0.003	-0.007	-0.004
5	-0.005	-0.004	-0.004	-0.003	-0.003	-0.003	-0.003	-0.003	-0.001	-0.001	-0.007	-0.003
6	-0.005	-0.004	-0.005	-0.009	-0.009	-0.009	-0.008	-0.019	-0.015	-0.008	-0.007	-0.003
7	-0.006	-0.008	-0.021	-0.033	-0.030	-0.040	-0.030	-0.068	-0.063	-0.052	-0.034	-0.017
8	-0.015	-0.026	-0.057	-0.081	-0.072	-0.101	-0.084	-0.151	-0.149	-0.137	-0.098	-0.065
9	-0.041	-0.064	-0.095	-0.129	-0.115	-0.161	-0.145	-0.231	-0.233	-0.226	-0.169	-0.132
10	-0.075	-0.100	-0.114	-0.130	-0.129	-0.182	-0.172	-0.250	-0.260	-0.259	-0.204	-0.178
11	-0.075	-0.090	-0.107	-0.110	-0.121	-0.139	-0.140	-0.205	-0.229	-0.218	-0.181	-0.182
12	-0.071	-0.092	-0.089	-0.081	-0.093	-0.096	-0.091	-0.140	-0.158	-0.152	-0.139	-0.153
13	-0.106	-0.130	-0.098	-0.078	-0.105	-0.075	-0.089	-0.093	-0.107	-0.100	-0.099	-0.114
14	-0.149	-0.176	-0.123	-0.110	-0.128	-0.095	-0.109	-0.080	-0.078	-0.073	-0.062	-0.070
15	-0.119	-0.150	-0.120	-0.106	-0.118	-0.090	-0.095	-0.060	-0.051	-0.042	-0.037	-0.035
16	-0.025	-0.049	-0.046	-0.039	-0.040	-0.033	-0.037	-0.021	-0.016	-0.010	-0.011	-0.009
17	-0.011	-0.015	-0.022	-0.020	-0.019	-0.018	-0.020	-0.008	-0.004	-0.003	-0.004	-0.004
18	-0.021	-0.007	-0.007	-0.007	-0.006	-0.005	-0.005	-0.002	-0.003	-0.003	-0.002	-0.002
19	-0.032	-0.016	-0.010	-0.013	-0.010	-0.012	-0.013	-0.005	-0.006	-0.009	-0.004	-0.005
20	-0.027	-0.007	-0.005	-0.005	-0.004	-0.003	-0.004	-0.002	-0.002	-0.003	-0.002	-0.003
21	-0.027	-0.005	-0.004	-0.003	-0.003	-0.009	-0.006	-0.001	-0.001	-0.001	-0.002	-0.002
22	-0.024	-0.006	-0.004	-0.003	-0.003	-0.010	-0.005	-0.001	-0.003	-0.001	-0.002	-0.001
23	-0.008	-0.004	-0.003	-0.003	-0.003	-0.009	-0.005	-0.001	-0.002	-0.001	-0.007	-0.007

FIGURE C-24: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS ON AN ELECTRIC VEHICLE (EV) RATE

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	Hour
0	0.002	0.034	0.008	0.019	0.031	0.041	0.027	0.037	0.046	0.024	0.014	0.007	0
1	0.002	0.004	0.013	0.047	0.015	0.015	0.018	0.026	0.024	0.018	0.007	0.003	1
2	0.002	0.004	0.014	0.016	0.005	0.009	0.009	0.015	0.014	0.010	0.004	0.003	2
3	0.002	0.004	0.004	0.011	0.004	0.008	0.008	0.011	0.011	0.007	0.002	0.001	3
4	0.002	0.004	0.004	0.009	0.004	0.008	0.007	0.011	0.010	0.006	0.002	0.001	4
5	0.000	0.003	0.003	0.009	0.003	0.005	0.006	0.010	0.010	0.006	0.002	0.001	5
6	0.000	0.003	0.003	0.004	0.002	0.005	0.006	0.009	0.010	0.010	0.002	0.001	6
7	0.000	0.003	0.001	0.002	0.001	0.005	0.005	0.006	0.008	0.009	0.005	0.005	7
8	0.000	0.006	0.009	0.001	0.001	0.003	0.007	0.005	0.005	0.006	0.005	0.005	8
9	0.000	0.007	0.009	0.001	0.001	0.004	0.008	0.004	0.004	0.006	0.005	0.006	9
10	0.000	0.007	0.003	0.002	0.001	0.009	0.009	0.015	0.015	0.012	0.006	0.005	10
11	0.050	0.038	0.029	0.026	0.021	0.026	0.023	0.024	0.021	0.021	0.015	0.013	11
12	0.053	0.042	0.026	0.026	0.022	0.026	0.024	0.026	0.024	0.025	0.017	0.017	12
13	0.012	0.000	0.005	0.008	0.022	0.051	0.053	0.053	0.052	0.050	0.017	0.014	13
14	0.010	0.004	0.013	0.021	0.036	0.086	0.088	0.073	0.071	0.070	0.051	0.050	14
15	0.029	0.017	0.027	0.037	0.050	0.109	0.099	0.093	0.090	0.085	0.083	0.081	15
16	0.065	0.047	0.040	0.044	0.053	0.170	0.168	0.153	0.138	0.098	0.100	0.102	16
17	0.076	0.088	0.058	0.054	0.065	0.125	0.135	0.135	0.118	0.120	0.114	0.101	17
18	0.065	0.109	0.084	0.074	0.070	0.081	0.105	0.121	0.111	0.108	0.104	0.087	18
19	0.038	0.098	0.071	0.078	0.083	0.078	0.085	0.111	0.107	0.098	0.076	0.056	19
20	0.025	0.090	0.066	0.067	0.067	0.053	0.059	0.070	0.073	0.062	0.056	0.041	20
21	0.015	0.084	0.053	0.058	0.056	0.048	0.050	0.057	0.060	0.053	0.035	0.023	21
22	0.009	0.067	0.082	0.107	0.126	0.061	0.060	0.046	0.062	0.055	0.029	0.016	22
23	0.009	0.156	0.046	0.048	0.059	0.040	0.039	0.037	0.058	0.035	0.020	0.007	23

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	-0.002	-0.023	-0.019	-0.019	-0.018	-0.021	-0.022	-0.010	-0.019	-0.030	-0.033	-0.030
1	-0.002	-0.034	-0.006	-0.002	-0.001	-0.004	-0.010	-0.007	-0.013	-0.016	-0.032	-0.027
2	-0.002	-0.025	-0.005	-0.002	-0.001	-0.001	-0.009	-0.009	-0.008	-0.008	-0.023	-0.015
3	-0.002	-0.010	-0.004	-0.002	-0.001	-0.001	-0.007	-0.007	-0.006	-0.006	-0.012	-0.006
4	-0.002	-0.003	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.003	-0.001
5	-0.002	-0.002	-0.001	-0.001	-0.004	-0.005	-0.002	-0.001	-0.001	-0.001	-0.004	-0.001
6	-0.002	-0.002	-0.003	-0.014	-0.025	-0.037	-0.020	-0.016	-0.011	-0.006	-0.004	-0.001
7	-0.002	-0.011	-0.021	-0.048	-0.065	-0.109	-0.077	-0.067	-0.057	-0.046	-0.021	-0.009
8	-0.016	-0.049	-0.048	-0.105	-0.121	-0.192	-0.156	-0.148	-0.141	-0.117	-0.068	-0.047
9	-0.047	-0.097	-0.089	-0.160	-0.167	-0.257	-0.223	-0.223	-0.234	-0.195	-0.130	-0.105
10	-0.097	-0.154	-0.141	-0.185	-0.189	-0.238	-0.249	-0.253	-0.263	-0.208	-0.168	-0.140
11	-0.110	-0.176	-0.148	-0.149	-0.138	-0.139	-0.184	-0.218	-0.212	-0.177	-0.153	-0.139
12	-0.084	-0.171	-0.127	-0.088	-0.085	-0.076	-0.109	-0.152	-0.147	-0.133	-0.118	-0.115
13	-0.082	-0.156	-0.092	-0.057	-0.054	-0.050	-0.070	-0.096	-0.092	-0.084	-0.081	-0.086
14	-0.082	-0.126	-0.077	-0.054	-0.045	-0.031	-0.048	-0.058	-0.059	-0.056	-0.040	-0.037
15	-0.052	-0.074	-0.052	-0.039	-0.034	-0.024	-0.029	-0.031	-0.026	-0.027	-0.016	-0.015
16	-0.008	-0.015	-0.012	-0.009	-0.008	-0.008	-0.008	-0.014	-0.010	-0.006	-0.002	-0.002
17	-0.004	-0.002	-0.003	-0.002	-0.003	-0.002	-0.003	-0.004	-0.001	-0.001	-0.001	0.000
18	-0.007	-0.001	-0.002	-0.002	-0.003	-0.012	-0.011	-0.006	-0.007	-0.004	-0.001	0.000
19	-0.015	-0.009	-0.006	-0.006	-0.003	-0.006	-0.004	-0.004	-0.002	-0.003	-0.007	-0.013
20	-0.011	-0.004	-0.005	-0.003	-0.001	-0.003	-0.002	-0.001	-0.002	-0.002	-0.003	-0.002
21	-0.010	-0.002	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.002	-0.002	-0.001	-0.001
22	-0.006	-0.002	-0.011	-0.012	-0.011	-0.036	-0.031	-0.020	-0.024	-0.018	-0.002	-0.001
23	-0.002	-0.008	-0.022	-0.024	-0.023	-0.036	-0.032	-0.017	-0.029	-0.039	-0.021	-0.029

FIGURE C-25: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR RESIDENTIAL PROJECTS ON A NON-EV TIME-OF-USE (TOU) RATE

	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
0	0.044	0.075	0.045	0.040	0.042	0.023	0.016	0.018	0.017	0.017	0.011	0.006	0
1	0.021	0.048	0.030	0.032	0.030	0.019	0.013	0.012	0.012	0.012	0.008	0.004	1
2	0.004	0.025	0.023	0.027	0.025	0.016	0.011	0.010	0.010	0.010	0.005	0.003	2
3	0.002	0.018	0.020	0.024	0.022	0.015	0.010	0.009	0.009	0.009	0.004	0.003	3
4	0.002	0.013	0.018	0.023	0.021	0.015	0.010	0.009	0.009	0.009	0.004	0.003	4
5	0.001	0.011	0.021	0.023	0.018	0.013	0.009	0.009	0.010	0.009	0.004	0.002	5
6	0.002	0.012	0.018	0.013	0.009	0.005	0.006	0.007	0.009	0.008	0.004	0.002	6
7	0.001	0.007	0.007	0.005	0.006	0.004	0.006	0.005	0.005	0.004	0.003	0.002	7
8	0.000	0.004	0.002	0.001	0.002	0.004	0.005	0.005	0.004	0.003	0.002	0.002	8
9	0.002	0.003	0.002	0.002	0.002	0.003	0.004	0.005	0.003	0.002	0.001	0.001	9
10	0.002	0.002	0.005	0.005	0.003	0.003	0.004	0.004	0.004	0.002	0.001	0.001	10
11	0.053	0.040	0.035	0.035	0.027	0.015	0.015	0.013	0.012	0.011	0.008	0.008	11
12	0.052	0.043	0.036	0.032	0.029	0.015	0.015	0.015	0.012	0.012	0.010	0.008	12
13	0.030	0.019	0.015	0.012	0.019	0.015	0.023	0.031	0.024	0.018	0.008	0.005	13
14	0.045	0.022	0.019	0.013	0.024	0.072	0.097	0.088	0.090	0.104	0.108	0.097	14
15	0.061	0.031	0.025	0.022	0.031	0.072	0.088	0.084	0.086	0.081	0.062	0.058	15
16	0.090	0.055	0.040	0.077	0.077	0.195	0.215	0.232	0.224	0.078	0.075	0.064	16
17	0.095	0.117	0.081	0.101	0.098	0.137	0.142	0.153	0.141	0.085	0.073	0.066	17
18	0.069	0.124	0.114	0.137	0.134	0.084	0.074	0.092	0.086	0.079	0.058	0.053	18
19	0.053	0.093	0.101	0.157	0.135	0.073	0.064	0.077	0.068	0.060	0.047	0.040	19
20	0.043	0.074	0.086	0.126	0.107	0.061	0.048	0.068	0.053	0.042	0.033	0.026	20
21	0.028	0.055	0.068	0.091	0.079	0.049	0.039	0.042	0.034	0.032	0.024	0.016	21
22	0.017	0.048	0.049	0.066	0.058	0.031	0.025	0.025	0.023	0.024	0.016	0.011	22
23	0.014	0.042	0.056	0.053	0.055	0.029	0.024	0.021	0.021	0.021	0.013	0.008	23

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
	-0.003	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
	-0.003	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
	-0.003	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
	-0.003	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
	-0.003	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.002
	-0.003	-0.002	-0.002	-0.002	-0.003	-0.003	-0.002	-0.002	-0.001	-0.001	-0.001	-0.002
	-0.003	-0.002	-0.004	-0.017	-0.026	-0.027	-0.017	-0.014	-0.009	-0.004	-0.001	-0.002
	-0.006	-0.015	-0.049	-0.105	-0.105	-0.106	-0.074	-0.070	-0.053	-0.036	-0.024	-0.010
	-0.048	-0.110	-0.144	-0.236	-0.208	-0.206	-0.159	-0.164	-0.144	-0.106	-0.081	-0.050
	-0.129	-0.213	-0.215	-0.289	-0.252	-0.280	-0.247	-0.260	-0.245	-0.173	-0.139	-0.112
	-0.173	-0.235	-0.202	-0.239	-0.212	-0.237	-0.246	-0.273	-0.274	-0.179	-0.148	-0.136
	-0.129	-0.165	-0.146	-0.147	-0.146	-0.132	-0.154	-0.183	-0.195	-0.139	-0.120	-0.119
	-0.084	-0.110	-0.102	-0.087	-0.097	-0.060	-0.076	-0.100	-0.109	-0.098	-0.086	-0.088
	-0.079	-0.101	-0.089	-0.067	-0.069	-0.036	-0.050	-0.062	-0.059	-0.059	-0.055	-0.058
	-0.071	-0.093	-0.076	-0.053	-0.058	-0.030	-0.038	-0.042	-0.034	-0.034	-0.027	-0.026
	-0.044	-0.059	-0.051	-0.040	-0.043	-0.024	-0.026	-0.024	-0.018	-0.017	-0.012	-0.011
	-0.017	-0.017	-0.012	-0.010	-0.016	-0.009	-0.009	-0.008	-0.004	-0.004	-0.003	-0.002
	-0.021	-0.015	-0.007	-0.005	-0.006	-0.005	-0.004	-0.003	-0.002	-0.002	-0.001	-0.001
	-0.025	-0.016	-0.010	-0.010	-0.008	-0.005	-0.005	-0.003	-0.003	-0.002	-0.002	-0.002
	-0.041	-0.030	-0.019	-0.016	-0.012	-0.007	-0.007	-0.004	-0.004	-0.004	-0.003	-0.003
	-0.034	-0.027	-0.016	-0.014	-0.011	-0.006	-0.006	-0.004	-0.003	-0.003	-0.003	-0.002
	-0.020	-0.013	-0.013	-0.014	-0.011	-0.006	-0.005	-0.004	-0.003	-0.003	-0.003	-0.002
	-0.013	-0.007	-0.009	-0.010	-0.007	-0.004	-0.004	-0.003	-0.002	-0.002	-0.002	-0.002
	-0.006	-0.002	-0.002	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001