2017 SGIP ADVANCED ENERGY STORAGE IMPACT EVALUATION

Submitted to:
Pacific Gas and Electric Company
SGIP Working Group

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2017 SGIP STORAGE IMPACT EVALUATION FOREWORD

Similar to last year's impact evaluation, the 2017 Self-Generation Incentive Program (SGIP) Storage Impact Evaluation finds that, in general, SGIP storage projects, while successful at reducing system peak demand, system costs and customer demand overall, continue to result in a net increase in greenhouse gas (GHG) emissions and fall short of the efficiency goals of the program. These results are somewhat to be expected, as the main driver of this behavior -- misalignment between retail rates and grid needs -- has not materially changed between the two evaluation periods (2016 and 2017).

Efforts are underway to address SGIP's GHG performance. The Commission convened a working group and subsequently directed Energy Division staff to propose new operational requirements based on the emissions of the electric grid and new verification and enforcement mechanisms to ensure compliance. The Commission issued the staff proposal for comment on September 6, 2018 and scheduled a workshop for October 22, 2018, with a proposed decision establishing new GHG rules expected in early 2019. It is important to note that, given implementation timeframes, it may be Q2/Q3 2019 before new rules take effect, and the impacts of those rules may not be seen until the 2019 or 2020 evaluations.

The report's other findings are numerous and equally deserving of attention. The report finds that storage has the potential to provide significant benefits when dispatched in response to granular signals about grid needs, and that storage participating in demand response programs like Capacity Bidding Program (CBP), which are linked to the CAISO market, can provide customer, environmental and system-level benefits simultaneously. It also finds that storage, if operated strictly as a load-modifier (under business-as-usual projections), is forecasted to produce a slight increase in overall system costs from 2018-2030, and that residential storage dispatched in response to new TOU periods may still lead to net increases in GHGs when operated to optimize customer bill savings. Staff looks forward to assessing these results, and their implications for possible policy changes, over the coming months.

Staff wishes to thank program participants who provided data to support the evaluation, the SGIP program administrators for their review of the report, and the Itron team, for their work to produce an impact evaluation whose findings draw attention to issues directly relevant to program design questions in multiple Commission program areas.

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1 EXECUTIVE SUMMARY

The Self-Generation Incentive Program (SGIP) was established legislatively in 2001 to help address peak electricity problems in California. 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.

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. Eligibility requirements for AES projects changed during subsequent years, most significantly in PY 2011 when standalone AES projects (in addition to those paired with SGIP eligible technologies or PV) were made eligible for incentives.

In 2016 the CPUC issued Decision (D.) 16-06-055 revising the SGIP pursuant to Senate Bill 861, Assembly Bill 1478 and implementing other changes. This Decision formally adopted three overarching goals for the SGIP:

- **Environmental:** The reduction of greenhouse gases (GHGs), the reduction of criteria air pollutants and the limitation of other environmental impacts such as water usage.
- **Grid Support:** 1) Reduce or shift peak demand, 2) Improve efficiency and reliability of the distribution and transmission system, 3) Lower grid infrastructure costs, 4) Provide ancillary services and 5) Ensure customer reliability.
- **Market Transformation:** SGIP should support technologies that have potential to thrive in future years without rebates.

This impact evaluation will assess the SGIP's progress towards some but not all of the goals established in D. 16-06-055.

1.1 PURPOSE AND SCOPE OF REPORT

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

- Net GHG emissions of AES systems as a class (i.e., all SGIP energy storage projects combined), and net GHG emissions differentiated between residential and nonresidential systems and between systems paired with renewable generation and non-paired systems.

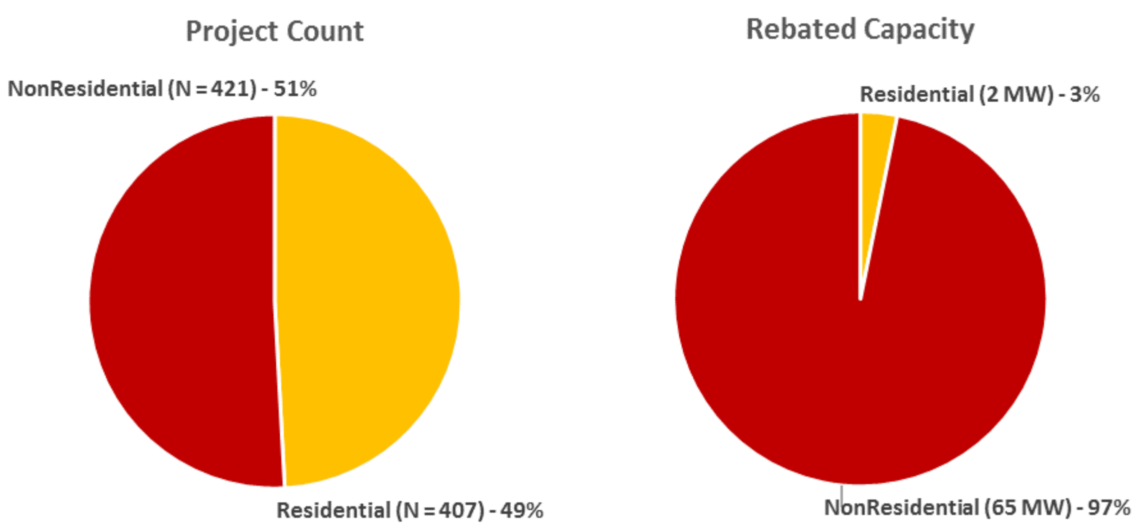
- Timing and duration of charge and discharge on an average basis, and identification of groups of storage systems exhibiting certain trends in the timing of charge and discharge.
- In accord with Public Utilities Code § 379.6(l)(6), quantify any contribution of energy storage projects to grid services where that storage substituted for and replaced planned investment into grid services.

This SGIP storage impact evaluation report is prepared in response to the CPUC's M&E Plan for calendar year 2017.

1.1.1 Scope of Report

This report evaluates the population of projects that received an upfront incentive from the SGIP on or before December 31, 2017. The population consists of 828 behind-the-meter (BTM) battery storage projects installed across the residential and nonresidential sectors representing almost 67 MW of SGIP rebated capacity.[1] Figure 1-1 shows the breakdown of project count and rebated capacity by customer type.

FIGURE 1-1: SGIP STORAGE PROJECT COUNT AND REBATED CAPACITY BY CUSTOMER TYPE

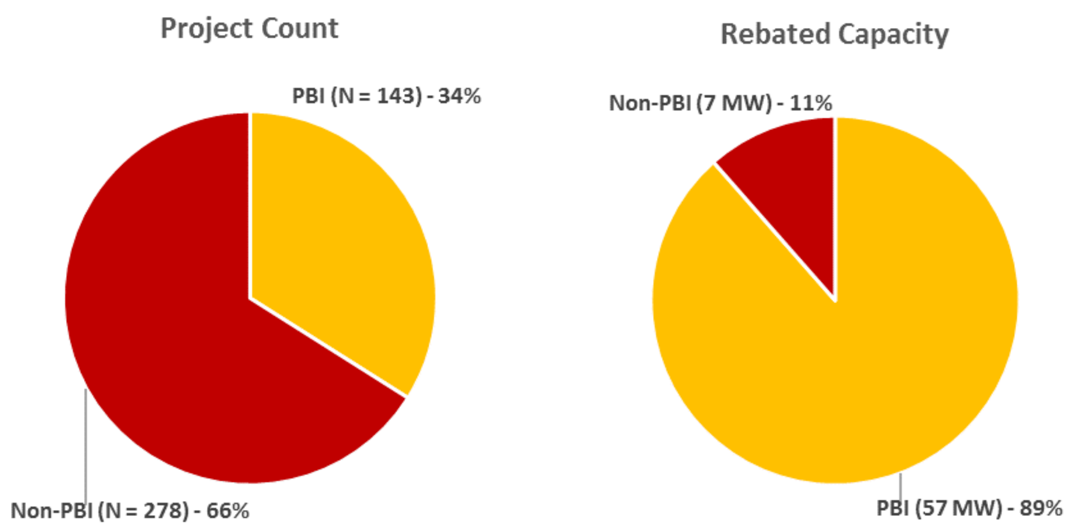


[1] SGIP rebated capacity is defined by the program as average discharge power across two hours. This SGIP capacity metric is designed to calculate incentive payments (and it is how the SGIP currently tracks system size), but it is not a direct indicator of inverter size.

While the number of projects installed across the sectors is almost equal, most of the SGIP storage rebated capacity (97%) is installed at nonresidential customer sites. Nonresidential projects are almost always larger and therefore have a significant contribution to total program impacts.

Projects are further split into two categories: 1) Performance Based Incentive (PBI)[2] 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 Senate Bill (SB) 412 provisions.[3] There are 143 PBI projects in the SGIP population representing roughly 57 MW of the 67 MW total SGIP storage rebated capacity. All PBI projects are installed at nonresidential customer locations. Figure 1-2 summarizes the proportion of nonresidential 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.

FIGURE 1-2: NONRESIDENTIAL ENERGY STORAGE PROJECTS BY PBI/NON-PBI CLASSIFICATION



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2 *2016 Self-Generation Incentive Program Handbook*, 2016, available at https://www.selfgenca.com/home/resources/

3 http://leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_cfa_20090417_154423_sen_comm.html

1.2 EVALUATION APPROACH

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

- Estimation of empirically 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, environmental or renewable integration benefits.

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. The findings presented in this report are based on a robust sample and found to be statistically significant for nonresidential and residential customers representing the program rebated capacity.

We employ two distinct approaches to quantify optimized, potential benefits of AES. The first uses 2017 marginal costs from Energy + Environmental Economics' (E3's) Distributed Energy Resource (DER) Avoided Cost Model. 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 marginal carbon dioxide emissions for the associated customer.

The second is a forward-looking, long-term integrated resource planning approach with E3's Renewable Energy Solutions (RESOLVE) model. RESOLVE is a capacity-planning and operations model that optimizes development of a high renewables grid to minimize cost while meeting reliability, flexibility and renewable portfolio standard (RPS) needs. Both models have been reviewed and adopted by the CPUC for use in other regulatory proceedings.

1.2.1 What's New in the 2017 Storage Impact Evaluation

This evaluation study is a continuation of the work performed in the 2016 SGIP Energy Storage Impact Evaluation Report.[4] All projects that were included in the 2016 evaluation are included in this study, in

4 http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454964

addition to the projects that received incentive payments during 2017. The evaluation team reported on all the same metrics as the 2016 report and added new analysis pieces. Below is a brief summary of major changes to the program population and the evaluation approach.

- The program population rebated capacity increased by 40%, largely due to significant growth in PBI projects.
- There was slight growth in residential projects relative to 2016. This report contains a quantitative assessment of residential project impacts, including GHG emissions.
- We have added estimates of criteria air pollutant impacts in addition to carbon dioxide emissions.
- SGIP storage customers remain on similar rates as they did in the 2016 evaluation, but our simulated dispatch analysis now explores the impacts of customers on proposed new rates.
- This analysis includes a deeper examination of SGIP energy storage participation in demand response (DR) programs.
- We revisit the treatment of parasitic loads and incorporate idle losses into ideal dispatch simulations.
- We include an analysis of the impact of SGIP energy storage on local distribution feeders, and we have included low and high marginal distribution cost sensitivities in our investigation of optimized system cost dispatch.

1.3 EVALUATION FINDINGS

Evaluation findings for a range of observed and simulated impacts are summarized below. A more detailed description of these impacts and the approaches taken to develop them are presented in more detail in Section 4, Section 5 and Section 6.

1.3.1 Performance Metrics

The evaluation team examined two key performance metrics of storage projects for this impact evaluation; capacity factors (CF) and roundtrip efficiencies (RTE).

The 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 rebated capacity of the system (in kW) and the total hours of operation.[5] The SGIP Handbook requires that PBI projects achieve an AES capacity factor of at least 10% to receive full payment. Non-PBI projects are not required to meet a 10% capacity factor.

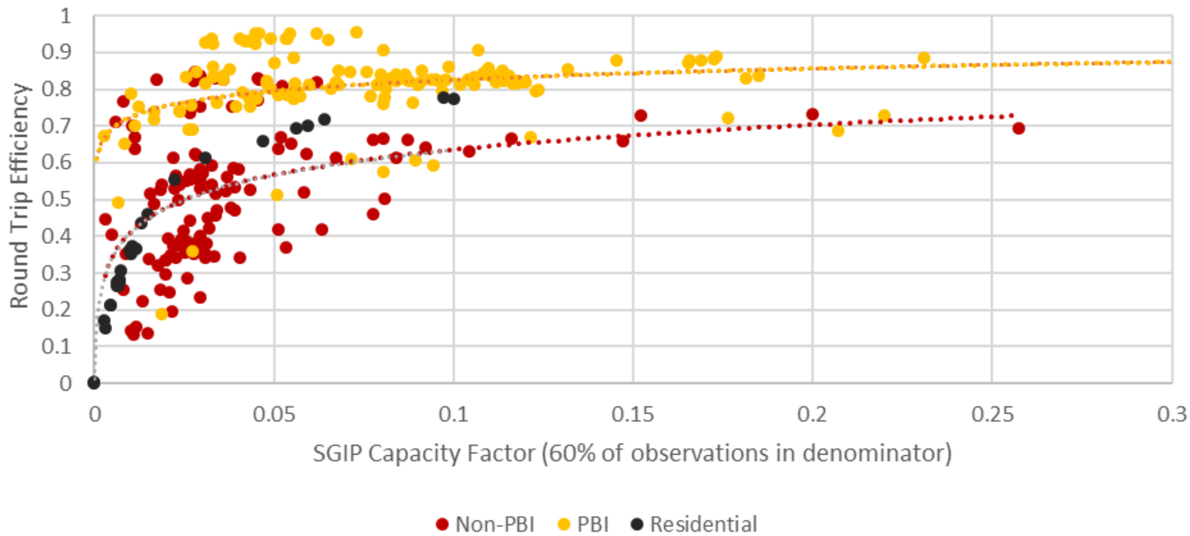
Another key performance metric is RTE, which is an eligibility requirement for the SGIP.[6] The RTE is defined as the total kWh discharge of the system divided by the total kWh charge and, for a given period of time, should range from 0% to 100%. For SGIP evaluation purposes, this metric was calculated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

The mean capacity factor was 4.3% for non-PBI nonresidential projects, 2.2% for non-PBI residential projects and 7.2% for PBI projects. The mean observed RTE was 51% for non-PBI nonresidential projects, 38% for non-PBI residential projects and 81% for PBI projects over the entire evaluation period. Figure 1-3 displays the project RTEs and CFs. 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 apparent in Figure 1-3. Systems with the lowest capacity factors tend to have the lowest RTEs. High capacity factors are usually associated with higher RTEs; however, PAs should be careful not to extrapolate this relationship to other performance metrics. While higher RTEs are desirable and minimize energy losses, the higher RTE alone does not guarantee improved greenhouse gas and system cost impacts.

5 The SGIP handbook assumes 5,200 maximum hours of operation in a year when calculating CF 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.” See 2015 SGIP Handbook, p. 37.

6 AES systems must maintain a round trip efficiency equal to or greater than 69.6% in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5%, assuming a 1% annual degradation rate. (2016 SGIP Handbook, https://www.selfgenca.com/documents/handbook/2016)

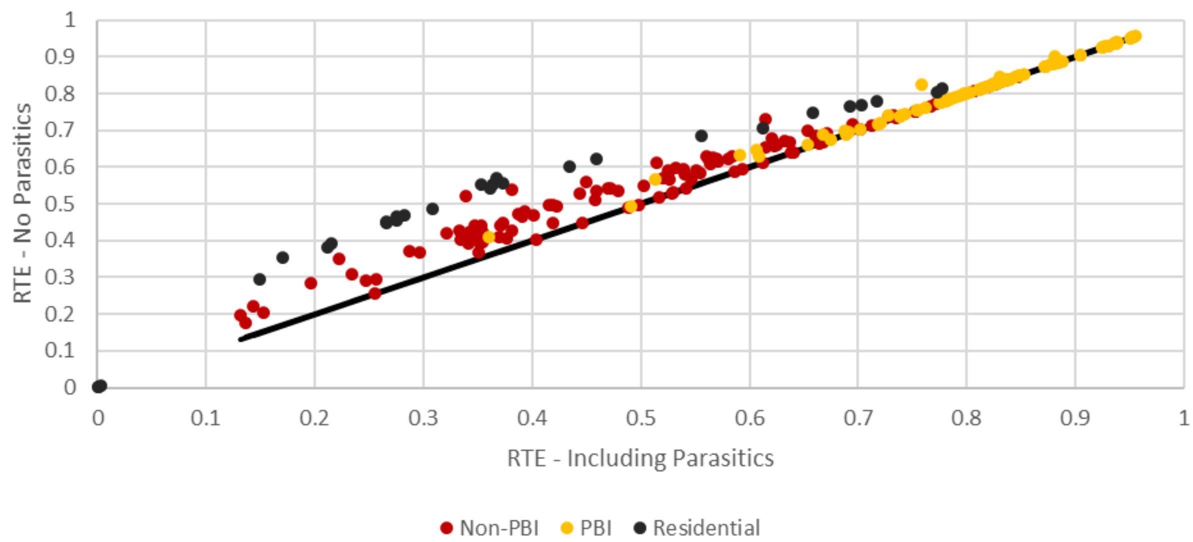
FIGURE 1-3: TOTAL ROUNDTRIP EFFICIENCY VERSUS CAPACITY FACTORS (ALL PROJECTS)



The evaluation team observed significant standby losses and parasitic loads associated with system cooling, communications and other power electronic loads when examining system data. While these low-power charge events were generally small at the 15-minute level, over the course of year, the impacts can become substantial, especially for a system that is under-utilized.

We estimated the impact that these small parasitic loads can have on system performance. For purposes of this analysis only, we set all small parasitic loads that were classified as “idle” to zero kWh rather than the actual parasitic load value. We then re-calculated the roundtrip efficiencies to quantify the impacts of those “idle” hours on RTE. The results of that analysis are presented below in Figure 1-4. The y-axis represents the system RTE with no parasitic loads (which approximates the single cycle RTE) and the x-axis represents the actual project RTE with the parasitic loads included. An observation on the black line means that the RTEs are identical – removing parasitic loads has 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 smaller non-PBI systems – those with RTEs in the 40% to 50% range – removal of the parasitic loads has an impact on the performance of the system. Projects in the 40% to 50% RTE range would exhibit RTEs in the 50% to 60% range if the parasitic loads were removed.

FIGURE 1-4: INFLUENCE OF PARASITICS ON ROUNDTRIP EFFICIENCY



We also examined how much the AES projects in the sample would have optimally been utilized in 2017 under each of the three simulated optimal dispatch approaches by calculating their theoretical SGIP capacity factors. SGIP AES projects dispatched ideally (simulations) to minimize system costs have a maximum SGIP capacity factor of 26%. Most of the system cost value is captured by these projects in a small number of high-cost hours that are generation capacity and/or distribution capacity constrained. All nonresidential AES projects in our sample show SGIP capacity factors of less than 10% when they are dispatched optimally to minimize customers' bills against 2017 retail tariffs. This suggests that the current capacity factor targets for PBI systems might be higher than what is optimally needed to minimize customer bills.

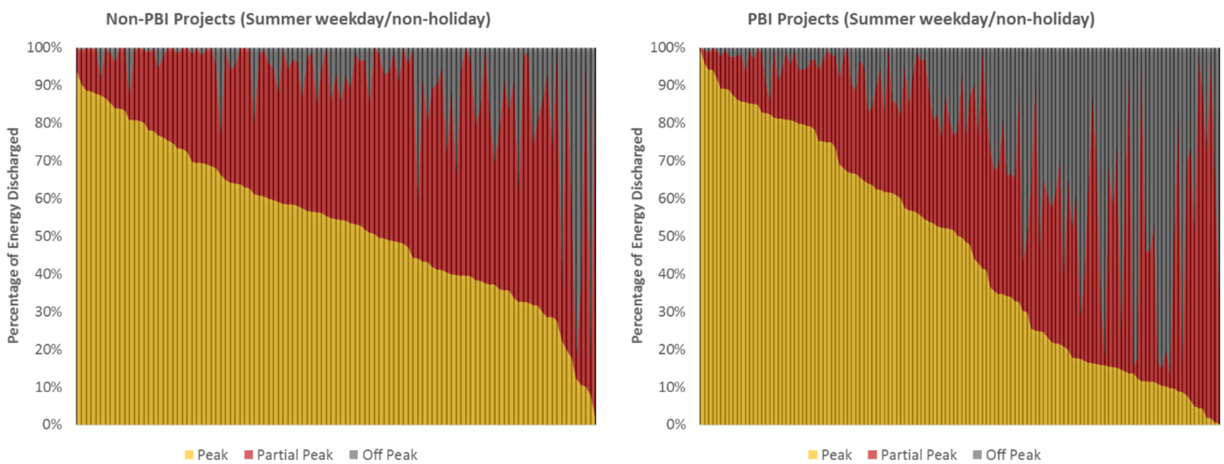
1.3.2 Observed Customer Impacts

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 time-of-use (TOU) rates may be incentivized to discharge energy during peak and partial-peak hours (as defined by tariffs) when retail energy rates are higher and avoid charging until off-peak hours when rates are lower.[7] Similarly, customers that are also on a rate that assesses demand charges at the monthly billing level may prioritize customer peak demand reduction.

[7] Unless otherwise noted, the terms "peak," "partial-peak," and "off-peak" refer to the periods as defined in the tariffs.

All SGIP nonresidential projects across all IOUs were on a TOU rate. Nonresidential projects are generally discharging during peak and partial-peak tariff periods when retail energy rates are higher. However, a significant percentage of nonresidential projects are also discharging during off-peak tariff hours (Figure 1-5). This behavior suggests that although storage systems are being utilized for some TOU arbitrage, this might not be the main explanation of dispatch behavior. Most residential projects in our sample were on tiered volumetric energy rates with no TOU periods, therefore we excluded them from this analysis.

FIGURE 1-5: SGIP NONRESIDENTIAL PROJECT DISCHARGE FOR SUMMER TOU PERIOD



It's important to note that Figure 1-5 represents all sampled projects regardless of customer rate structure. A customer on a TOU energy-only rate has no incentive to discharge during off-peak TOU periods (when energy rates are lower) whereas a customer with demand charges could be more incentivized to discharge during off-peak tariff hours if their peak load was coincident with the TOU off-peak period. We obtained rate information for 234 of the 248 projects in the nonresidential sample. Only eleven of those projects were on a TOU energy-only rate with no demand charge. The remaining 223 projects had some sort of non-coincident demand charge assessed at the monthly level, or a non-coincident monthly demand charge plus an additional peak period demand charge.

Figure 1-6 shows the percentage of nonresidential project-months that either increased, decreased or did not modify a customer's peak demand for a given month. While not addressing the magnitude of peak demand impact, Figure 1-6 shows that during all months most PBI and non-PBI nonresidential projects are reducing customer peak demand. Residential projects are excluded from this analysis as they are not subject to non-coincident demand charges.

Figure 1-6 also shows a small percentage of energy storage systems consistently adding to monthly non-coincident peak demand. For customers on TOU energy-only rates without non-coincident demand charges, this behavior is expected since no incentive exists to reduce demand. However most of the time this increase in non-coincident demand is explained by imperfect storage dispatch. SGIP AES systems try to reduce customer demand charges but sometimes fail to do so on a given month due to unexpected facility operations. However, the majority of energy storage systems are successfully reducing customer non-coincident peak demand.

FIGURE 1-6: MONTHLY PEAK DEMAND FOR NONRESIDENTIAL PROJECTS

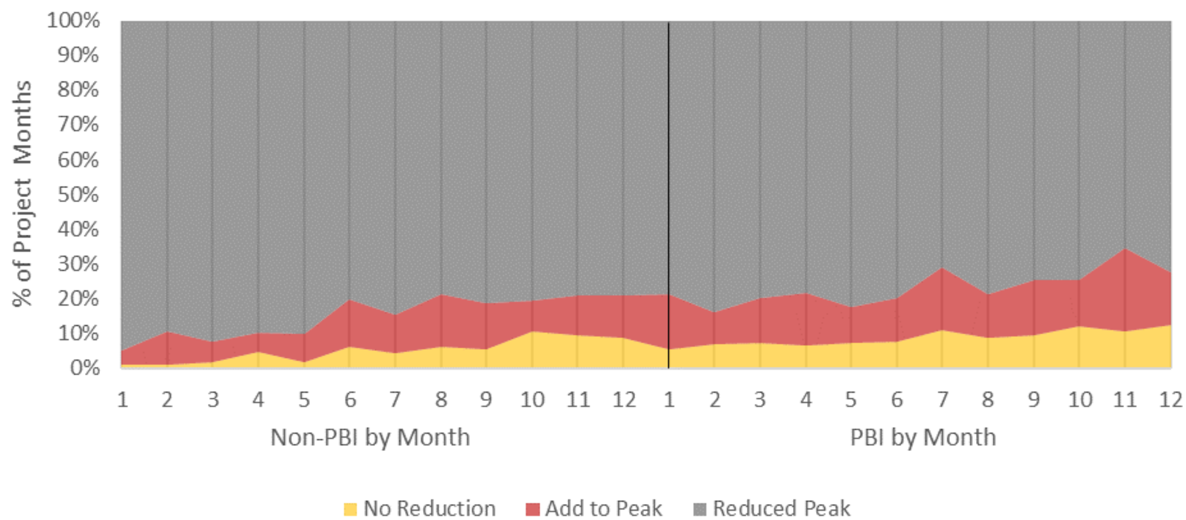
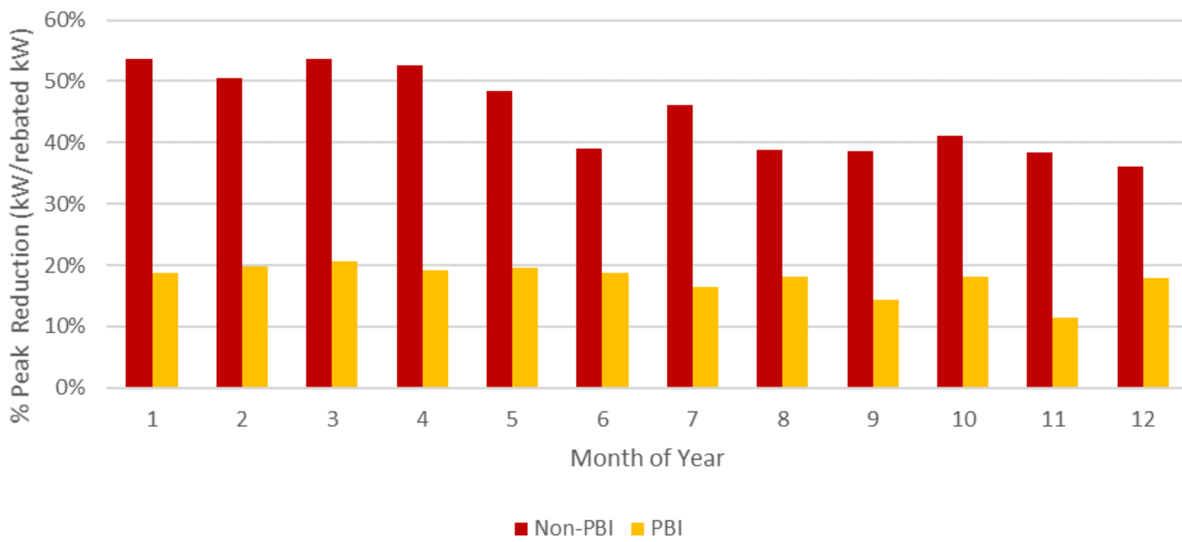


Figure 1-7 below shows the magnitude of average monthly customer peak demand reductions normalized by SGIP rebated capacity. A value of 100% would indicate that a 1 MW AES project reduces a customer's monthly peak demand by 1 MW.

FIGURE 1-7: MONTHLY CUSTOMER PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

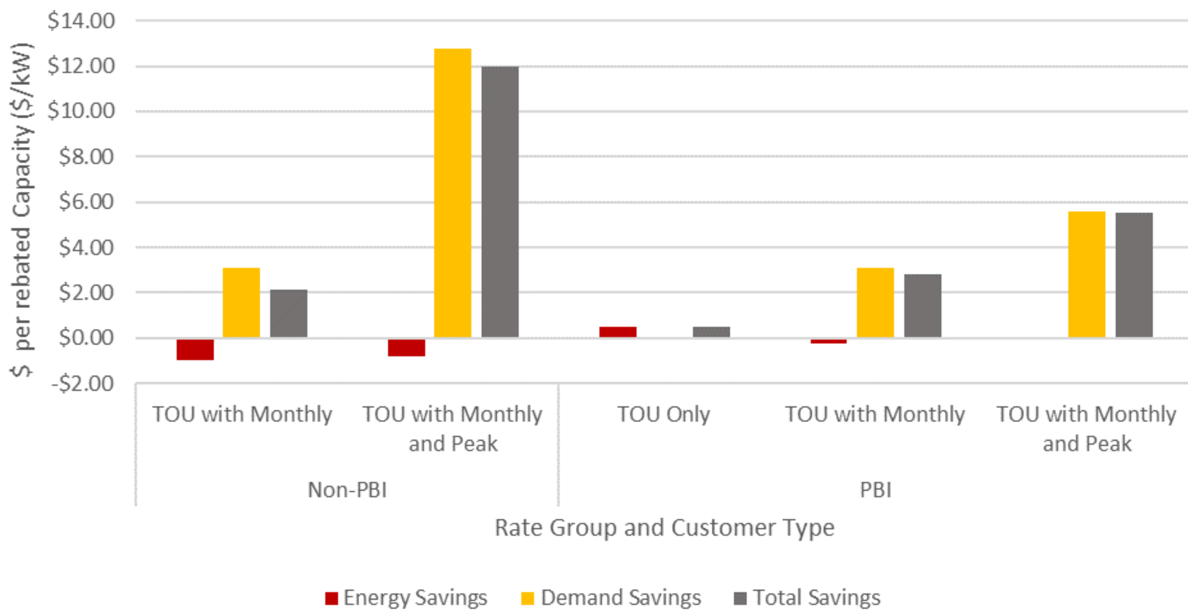


Non-PBI projects reduced monthly customer peak demand by approximately 45% of their rebated capacity over the course of the year. In contrast, larger PBI projects reduced monthly customer peak demand by approximately 18% of their rebated capacity. The larger demand reductions for non-PBI projects relative to their rebated capacity suggests prioritization of this use-case over others. Overall, nonresidential SGIP AES projects reduced customer summer peak demand by roughly 2,400 kW during 2017 (approximately 4% of SGIP AES rebated capacity).

We combined the energy rates charged during each of the TOU periods and compared energy consumption with storage versus 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 demand charge reduction or peak tariff period demand charge reduction, perhaps, at the expense of energy bill savings. Figure 1-8 presents those results for PBI and non-PBI nonresidential projects by rate type.[8] The vertical axis represents the average monthly savings (or cost) in dollars, normalized by SGIP rebated capacity.

[8] In Figure 1-8, "TOU Only" represents an energy only tariff, "TOU with Monthly" refers to an energy rate with a monthly demand charge and "TOU with Monthly and Peak" are customers who are assessed an additional demand charge during TOU defined partial-peak and/or peak periods.

FIGURE 1-8: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KW) BY RATE GROUP AND PBI/NON-PBI



For both non-PBI rate types[9], customers incurred energy costs, on average, by utilizing their storage systems. However, both groups realized significant bill savings by optimizing their storage system to reduce peak and/or monthly demand charges. PBI projects on a TOU energy-only rate (10 customers) realized bill savings on energy charges from the storage systems which suggests they were optimizing dispatch for TOU arbitrage. PBI customers with demand charges[10] realized bill savings from demand reduction, while energy charges had a negligible effect on their bill.

1.3.3 Overall Observed Energy Storage Discharge Patterns

The evaluation team 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 kW discharge and charge (normalized by rebated kW capacity) for each month and hour within the year for both non-PBI and PBI projects.

[9] Only 1 non-PBI customer was on a TOU only rate in 2017 (not shown). Thirty-one customers were on a rate that assessed monthly demand charges and 80 customers were on a rate that assessed a monthly demand charge and a peak demand charge.

[10] Forty-three customers were on a rate that assessed monthly demand charges and 63 customers were on a rate that assessed a monthly demand charge and a peak demand charge.

There are significant differences between the PBI, non-PBI nonresidential and residential projects when examining charge and discharge (kW) on an average hourly basis. Figure 1-9 presents the findings for PBI projects. Discharging is positive and is shown in green and charging is negative and is shown in red.

FIGURE 1-9: AVERAGE HOURLY CHARGE/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	0.012	0.009	0.008	0.019	0.021	0.023	0.028	0.050	0.060	0.063	0.059	0.057
1	0.017	0.015	0.007	0.011	0.013	0.016	0.024	0.045	0.057	0.058	0.060	0.059
2	0.010	0.008	0.004	0.011	0.014	0.016	0.025	0.046	0.058	0.061	0.059	0.057
3	0.010	0.007	0.004	0.012	0.013	0.015	0.025	0.046	0.059	0.062	0.062	0.061
4	0.010	0.008	0.004	0.005	0.005	0.004	0.017	0.021	0.028	0.025	0.057	0.061
5	0.012	0.009	0.006	0.006	0.008	0.006	0.020	0.025	0.028	0.026	0.026	0.024
6	0.024	0.018	0.013	0.018	0.018	0.016	0.025	0.032	0.036	0.033	0.032	0.024
7	0.030	0.023	0.020	0.022	0.019	0.015	0.021	0.028	0.032	0.027	0.030	0.030
8	0.031	0.026	0.029	0.031	0.025	0.018	0.025	0.034	0.040	0.036	0.027	0.027
9	0.046	0.040	0.036	0.036	0.033	0.025	0.029	0.039	0.041	0.040	0.036	0.033
10	0.045	0.041	0.043	0.036	0.042	0.032	0.037	0.052	0.045	0.048	0.040	0.036
11	0.044	0.041	0.048	0.038	0.055	0.049	0.048	0.070	0.061	0.066	0.044	0.041
12	0.040	0.041	0.051	0.043	0.057	0.052	0.050	0.075	0.064	0.071	0.050	0.043
13	0.040	0.042	0.049	0.041	0.054	0.049	0.051	0.069	0.059	0.065	0.052	0.046
14	0.040	0.041	0.043	0.037	0.064	0.067	0.073	0.081	0.077	0.068	0.048	0.044
15	0.040	0.039	0.040	0.037	0.065	0.075	0.077	0.088	0.089	0.065	0.046	0.043
16	0.045	0.042	0.055	0.062	0.070	0.084	0.081	0.097	0.096	0.073	0.049	0.056
17	0.083	0.075	0.084	0.080	0.044	0.034	0.038	0.045	0.052	0.069	0.080	0.064
18	0.104	0.096	0.118	0.110	0.062	0.045	0.056	0.058	0.071	0.082	0.084	0.073
19	0.142	0.131	0.123	0.105	0.078	0.058	0.074	0.072	0.080	0.088	0.094	0.086
20	0.141	0.132	0.081	0.059	0.053	0.047	0.057	0.057	0.064	0.057	0.076	0.085
21	0.083	0.075	0.037	0.033	0.048	0.048	0.055	0.078	0.087	0.084	0.054	0.044
22	0.019	0.016	0.018	0.038	0.042	0.043	0.055	0.079	0.081	0.086	0.075	0.068
23	0.043	0.032	0.011	0.012	0.015	0.017	0.027	0.049	0.058	0.059	0.077	0.076

	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	-0.185	-0.168	-0.141	-0.136	-0.132	-0.138	-0.141	-0.172	-0.184	-0.166	-0.177	-0.168
1	-0.165	-0.150	-0.113	-0.103	-0.096	-0.103	-0.106	-0.138	-0.144	-0.129	-0.154	-0.149
2	-0.121	-0.109	-0.083	-0.076	-0.067	-0.071	-0.077	-0.099	-0.110	-0.107	-0.120	-0.119
3	-0.090	-0.080	-0.058	-0.055	-0.050	-0.048	-0.055	-0.079	-0.093	-0.093	-0.097	-0.096
4	-0.063	-0.057	-0.042	-0.038	-0.039	-0.036	-0.042	-0.058	-0.072	-0.071	-0.082	-0.087
5	-0.044	-0.040	-0.028	-0.022	-0.023	-0.020	-0.028	-0.032	-0.041	-0.038	-0.059	-0.064
6	-0.031	-0.027	-0.019	-0.020	-0.021	-0.018	-0.026	-0.027	-0.034	-0.033	-0.033	-0.036
7	-0.025	-0.021	-0.021	-0.019	-0.019	-0.017	-0.024	-0.024	-0.030	-0.029	-0.032	-0.031
8	-0.023	-0.024	-0.028	-0.026	-0.025	-0.020	-0.031	-0.037	-0.041	-0.039	-0.033	-0.031
9	-0.033	-0.032	-0.028	-0.022	-0.022	-0.018	-0.027	-0.035	-0.037	-0.038	-0.039	-0.039
10	-0.035	-0.028	-0.024	-0.020	-0.019	-0.017	-0.027	-0.031	-0.036	-0.034	-0.034	-0.038
11	-0.033	-0.025	-0.023	-0.017	-0.015	-0.013	-0.022	-0.025	-0.033	-0.030	-0.031	-0.036
12	-0.028	-0.023	-0.021	-0.015	-0.012	-0.013	-0.021	-0.024	-0.031	-0.028	-0.032	-0.032
13	-0.025	-0.021	-0.020	-0.016	-0.015	-0.014	-0.025	-0.032	-0.040	-0.037	-0.032	-0.029
14	-0.024	-0.023	-0.024	-0.020	-0.021	-0.016	-0.024	-0.035	-0.040	-0.039	-0.036	-0.029
15	-0.027	-0.024	-0.032	-0.028	-0.030	-0.019	-0.023	-0.046	-0.040	-0.047	-0.036	-0.031
16	-0.029	-0.030	-0.026	-0.017	-0.030	-0.020	-0.025	-0.049	-0.038	-0.050	-0.032	-0.029
17	-0.020	-0.017	-0.024	-0.021	-0.037	-0.030	-0.039	-0.064	-0.045	-0.052	-0.026	-0.028
18	-0.024	-0.020	-0.021	-0.019	-0.028	-0.031	-0.036	-0.047	-0.038	-0.043	-0.026	-0.031
19	-0.024	-0.022	-0.031	-0.038	-0.024	-0.026	-0.029	-0.039	-0.037	-0.040	-0.033	-0.032
20	-0.041	-0.046	-0.040	-0.039	-0.036	-0.029	-0.037	-0.042	-0.045	-0.052	-0.065	-0.031
21	-0.052	-0.052	-0.093	-0.126	-0.126	-0.107	-0.120	-0.141	-0.149	-0.169	-0.076	-0.067
22	-0.155	-0.141	-0.123	-0.117	-0.124	-0.119	-0.123	-0.163	-0.178	-0.165	-0.160	-0.150
23	-0.131	-0.118	-0.138	-0.155	-0.159	-0.155	-0.163	-0.200	-0.206	-0.197	-0.159	-0.136

PBI projects illustrate a clear signature of charge and discharge throughout the year. During the summer months, they discharge, on average, more significantly between 3 pm and 8 pm. During winter months, discharging generally comes later in the day compared to summer hours. Average hourly kW charge is predominant in the late evening hours (from 10 pm to 2 am) throughout both seasons.

Non-PBI projects, conversely, exhibit more variability with regards to charging and discharging throughout the day. Figure 1-10 conveys these results. For non-PBI projects, the magnitude of charge and discharge kW within the same hour 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 non-PBI systems are being utilized to perform peak demand shaving at the expense of TOU arbitrage.

FIGURE 1-10: AVERAGE HOURLY CHARGE/DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI NONRESIDENTIAL 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	0.018	0.015	0.011	0.021	0.024	0.027	0.027	0.023	0.016	0.012	0.007	0.006
1	0.025	0.023	0.009	0.010	0.014	0.015	0.012	0.012	0.003	0.002	0.012	0.014
2	0.008	0.010	0.002	0.010	0.011	0.012	0.011	0.012	0.003	0.001	0.001	0.002
3	0.008	0.009	0.002	0.010	0.013	0.013	0.011	0.012	0.003	0.001	0.002	0.002
4	0.008	0.009	0.003	0.005	0.005	0.004	0.003	0.005	0.004	0.005	0.004	0.006
5	0.013	0.015	0.012	0.012	0.011	0.011	0.007	0.010	0.007	0.015	0.011	0.008
6	0.028	0.025	0.021	0.014	0.017	0.018	0.011	0.015	0.010	0.011	0.016	0.015
7	0.035	0.027	0.026	0.020	0.021	0.022	0.017	0.020	0.015	0.014	0.016	0.014
8	0.031	0.033	0.033	0.028	0.029	0.034	0.027	0.028	0.020	0.020	0.018	0.015
9	0.037	0.040	0.040	0.032	0.034	0.041	0.036	0.036	0.025	0.028	0.022	0.019
10	0.038	0.042	0.046	0.033	0.047	0.060	0.052	0.054	0.032	0.038	0.028	0.019
11	0.036	0.040	0.050	0.040	0.052	0.059	0.047	0.055	0.034	0.040	0.030	0.020
12	0.037	0.044	0.051	0.043	0.052	0.059	0.048	0.053	0.032	0.045	0.032	0.022
13	0.038	0.045	0.054	0.043	0.048	0.057	0.046	0.052	0.032	0.046	0.033	0.025
14	0.035	0.040	0.049	0.036	0.038	0.051	0.039	0.046	0.028	0.039	0.028	0.026
15	0.026	0.038	0.048	0.036	0.037	0.045	0.036	0.038	0.024	0.033	0.023	0.022
16	0.026	0.037	0.057	0.059	0.034	0.051	0.044	0.036	0.023	0.027	0.023	0.032
17	0.050	0.064	0.058	0.039	0.028	0.036	0.025	0.024	0.016	0.027	0.050	0.029
18	0.045	0.055	0.056	0.040	0.021	0.023	0.018	0.022	0.015	0.020	0.037	0.025
19	0.035	0.044	0.031	0.021	0.017	0.020	0.017	0.017	0.009	0.014	0.027	0.021
20	0.021	0.024	0.012	0.010	0.007	0.009	0.009	0.009	0.005	0.009	0.015	0.018
21	0.016	0.016	0.009	0.017	0.016	0.018	0.017	0.018	0.006	0.006	0.008	0.010
22	0.011	0.013	0.005	0.013	0.013	0.015	0.013	0.016	0.004	0.004	0.006	0.006
23	0.009	0.011	0.005	0.013	0.015	0.016	0.017	0.016	0.005	0.005	0.005	0.005

	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	-0.036	-0.041	-0.037	-0.048	-0.050	-0.051	-0.051	-0.045	-0.040	-0.035	-0.031	-0.027
1	-0.051	-0.053	-0.033	-0.036	-0.039	-0.039	-0.039	-0.038	-0.027	-0.024	-0.034	-0.032
2	-0.035	-0.040	-0.025	-0.032	-0.035	-0.037	-0.035	-0.033	-0.024	-0.020	-0.024	-0.020
3	-0.029	-0.034	-0.022	-0.031	-0.034	-0.036	-0.033	-0.034	-0.023	-0.019	-0.021	-0.017
4	-0.028	-0.033	-0.023	-0.028	-0.031	-0.031	-0.029	-0.030	-0.023	-0.020	-0.022	-0.017
5	-0.028	-0.033	-0.024	-0.027	-0.028	-0.026	-0.024	-0.028	-0.025	-0.024	-0.023	-0.019
6	-0.033	-0.038	-0.030	-0.030	-0.032	-0.029	-0.028	-0.029	-0.025	-0.031	-0.029	-0.024
7	-0.041	-0.041	-0.041	-0.033	-0.033	-0.031	-0.029	-0.028	-0.024	-0.026	-0.032	-0.030
8	-0.040	-0.041	-0.053	-0.045	-0.042	-0.041	-0.039	-0.040	-0.034	-0.038	-0.031	-0.027
9	-0.054	-0.057	-0.058	-0.045	-0.047	-0.047	-0.043	-0.048	-0.036	-0.038	-0.044	-0.035
10	-0.057	-0.063	-0.060	-0.052	-0.051	-0.053	-0.050	-0.053	-0.042	-0.044	-0.042	-0.037
11	-0.061	-0.064	-0.063	-0.050	-0.056	-0.064	-0.062	-0.060	-0.046	-0.051	-0.048	-0.039
12	-0.062	-0.061	-0.067	-0.055	-0.058	-0.064	-0.059	-0.062	-0.047	-0.051	-0.050	-0.037
13	-0.059	-0.063	-0.064	-0.059	-0.066	-0.071	-0.063	-0.068	-0.049	-0.055	-0.052	-0.038
14	-0.060	-0.063	-0.069	-0.058	-0.068	-0.075	-0.064	-0.075	-0.050	-0.060	-0.053	-0.039
15	-0.062	-0.064	-0.071	-0.059	-0.064	-0.077	-0.065	-0.072	-0.053	-0.060	-0.052	-0.044
16	-0.057	-0.066	-0.074	-0.060	-0.064	-0.073	-0.060	-0.071	-0.051	-0.063	-0.047	-0.046
17	-0.051	-0.062	-0.077	-0.072	-0.067	-0.088	-0.072	-0.075	-0.054	-0.061	-0.044	-0.045
18	-0.057	-0.069	-0.079	-0.065	-0.061	-0.077	-0.062	-0.062	-0.045	-0.052	-0.051	-0.043
19	-0.065	-0.071	-0.084	-0.070	-0.050	-0.067	-0.051	-0.055	-0.038	-0.043	-0.055	-0.041
20	-0.071	-0.079	-0.055	-0.038	-0.039	-0.045	-0.037	-0.036	-0.026	-0.030	-0.063	-0.036
21	-0.050	-0.049	-0.043	-0.050	-0.054	-0.064	-0.058	-0.054	-0.033	-0.038	-0.037	-0.036
22	-0.048	-0.049	-0.035	-0.044	-0.049	-0.054	-0.046	-0.043	-0.029	-0.031	-0.035	-0.034
23	-0.037	-0.043	-0.031	-0.041	-0.041	-0.041	-0.039	-0.040	-0.027	-0.029	-0.031	-0.029

Figure 1-11 shows dispatch patterns for residential projects in our sample. These projects generally discharge from late morning starting at 11am until midafternoon at about 4 pm. They are consistently charging directly after this period, from 4 pm until midnight, often increasing the non-coincident peak demand consumption. This increase in non-coincident peak demand has no financial consequence as residential customers are not currently subject to demand charges.

FIGURE 1-11: AVERAGE HOURLY CHARGE/DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI 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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
11	0.053	0.053	0.049	0.041	0.046	0.053	0.036	0.038	0.047	0.081	0.139	0.158
12	0.052	0.052	0.046	0.066	0.072	0.078	0.060	0.063	0.059	0.087	0.139	0.158
13	0.052	0.050	0.046	0.065	0.073	0.077	0.060	0.062	0.053	0.035	0.022	0.055
14	0.052	0.050	0.046	0.067	0.075	0.079	0.062	0.063	0.053	0.034	0.017	0.054
15	0.034	0.040	0.039	0.063	0.066	0.070	0.057	0.055	0.040	0.028	0.016	0.044
16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.012	0.040
17	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

	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	-0.007	-0.010	-0.013	-0.012	-0.012	-0.010	-0.010	-0.010	-0.009	-0.008	-0.006	-0.007
1	-0.007	-0.009	-0.011	-0.010	-0.010	-0.009	-0.011	-0.009	-0.008	-0.008	-0.007	-0.006
2	-0.007	-0.009	-0.011	-0.009	-0.010	-0.009	-0.010	-0.009	-0.008	-0.009	-0.007	-0.007
3	-0.006	-0.010	-0.010	-0.008	-0.009	-0.009	-0.009	-0.008	-0.010	-0.009	-0.007	-0.007
4	-0.006	-0.009	-0.009	-0.009	-0.009	-0.009	-0.008	-0.009	-0.008	-0.008	-0.007	-0.007
5	-0.005	-0.007	-0.009	-0.009	-0.009	-0.010	-0.009	-0.010	-0.008	-0.009	-0.007	-0.008
6	-0.005	-0.008	-0.010	-0.010	-0.010	-0.011	-0.009	-0.010	-0.011	-0.009	-0.008	-0.007
7	-0.007	-0.009	-0.010	-0.010	-0.011	-0.011	-0.009	-0.010	-0.010	-0.009	-0.008	-0.007
8	-0.007	-0.008	-0.009	-0.009	-0.009	-0.010	-0.009	-0.011	-0.008	-0.010	-0.007	-0.007
9	-0.006	-0.008	-0.010	-0.009	-0.009	-0.009	-0.009	-0.010	-0.009	-0.010	-0.008	-0.007
10	-0.006	-0.008	-0.009	-0.009	-0.010	-0.010	-0.010	-0.009	-0.009	-0.009	-0.007	-0.008
11	-0.005	-0.006	-0.008	-0.008	-0.009	-0.008	-0.008	-0.008	-0.007	-0.005	-0.003	-0.001
12	-0.004	-0.006	-0.009	-0.008	-0.008	-0.008	-0.009	-0.007	-0.006	-0.006	-0.003	-0.001
13	-0.005	-0.007	-0.008	-0.008	-0.007	-0.008	-0.010	-0.008	-0.010	-0.028	-0.053	-0.045
14	-0.005	-0.006	-0.008	-0.008	-0.007	-0.008	-0.009	-0.008	-0.015	-0.060	-0.129	-0.110
15	-0.006	-0.007	-0.010	-0.008	-0.008	-0.010	-0.009	-0.011	-0.021	-0.064	-0.133	-0.115
16	-0.046	-0.047	-0.048	-0.050	-0.054	-0.061	-0.046	-0.045	-0.049	-0.038	-0.038	-0.043
17	-0.044	-0.047	-0.045	-0.055	-0.060	-0.064	-0.051	-0.052	-0.051	-0.033	-0.019	-0.037
18	-0.043	-0.044	-0.042	-0.054	-0.060	-0.064	-0.051	-0.052	-0.050	-0.038	-0.023	-0.063
19	-0.042	-0.044	-0.041	-0.060	-0.063	-0.070	-0.058	-0.061	-0.057	-0.052	-0.040	-0.094
20	-0.041	-0.044	-0.042	-0.060	-0.066	-0.069	-0.054	-0.052	-0.042	-0.039	-0.033	-0.078
21	-0.040	-0.043	-0.043	-0.059	-0.065	-0.069	-0.054	-0.054	-0.041	-0.036	-0.030	-0.074
22	-0.038	-0.041	-0.039	-0.051	-0.058	-0.058	-0.048	-0.049	-0.041	-0.032	-0.025	-0.061
23	-0.021	-0.027	-0.026	-0.039	-0.036	-0.033	-0.029	-0.029	-0.022	-0.015	-0.009	-0.011

1.3.4 Demand Response Participation

DR programs provide an incentive to customers to reduce (or shift) electricity consumption during periods of real (or perceived) high stress on the grid. 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 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 2017. Overall, SGIP projects are responding to DR programs by discharging throughout event periods and, by extension, reducing energy consumption behind-the-meter.[11]

Systems that were net discharging throughout the respective DR event hours also decreased GHG emissions and provided a net utility cost benefit. The magnitude of GHG reductions and avoided costs are

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

predicated on several factors, including the number of event calls, the duration of those events, the number of projects participating and the size of the storage system behind-the-meter. DR programs like the capacity bidding program (CBP) allow BTM systems to participate in the day-ahead CAISO market and are triggered during periods of high system-level stress. These events generally coincide with periods of high marginal utility costs, especially during hours that are generation capacity and/or distribution capacity constrained.

While it is intuitive that storage projects will produce GHG emission reductions and utility marginal cost savings when discharging throughout DR event periods, these systems will ultimately have to charge again throughout the day. Since AES technologies inherently consume more energy during charging relative to energy discharged, the marginal emissions rate or utility cost must be lower during charging hours relative to discharge hours to realize benefits.

The evaluation team conducted an analysis of each project participating in their respective DR program by comparing the performance of the system during DR event days compared to non-event days. We analyzed the storage utilization, GHG emissions and utility marginal costs (by project) for each day of each week[12] when at least one DR event was called. We then developed an average capacity factor across those days and determined the percentage of total days across all projects where there was a reduction in GHG emissions and utility marginal costs.

For most programs, there is very little variation in storage utilization from days where DR events were called compared to non-event days. The more significant difference is in the number of days with GHG emission and utility marginal cost reductions, especially for programs like CBP, supply-side pilot (SSP), excess supply pilot (XSP) and critical peak pricing (CPP) in San Diego Gas and Electric territory. The projects participating in CBP reduced GHG emissions on 37% of the event days compared to 20% of non-event days. SSP projects exhibit a similar pattern (48% of event days and 27% of non-event days).

1.3.5 Observed CAISO System Impacts

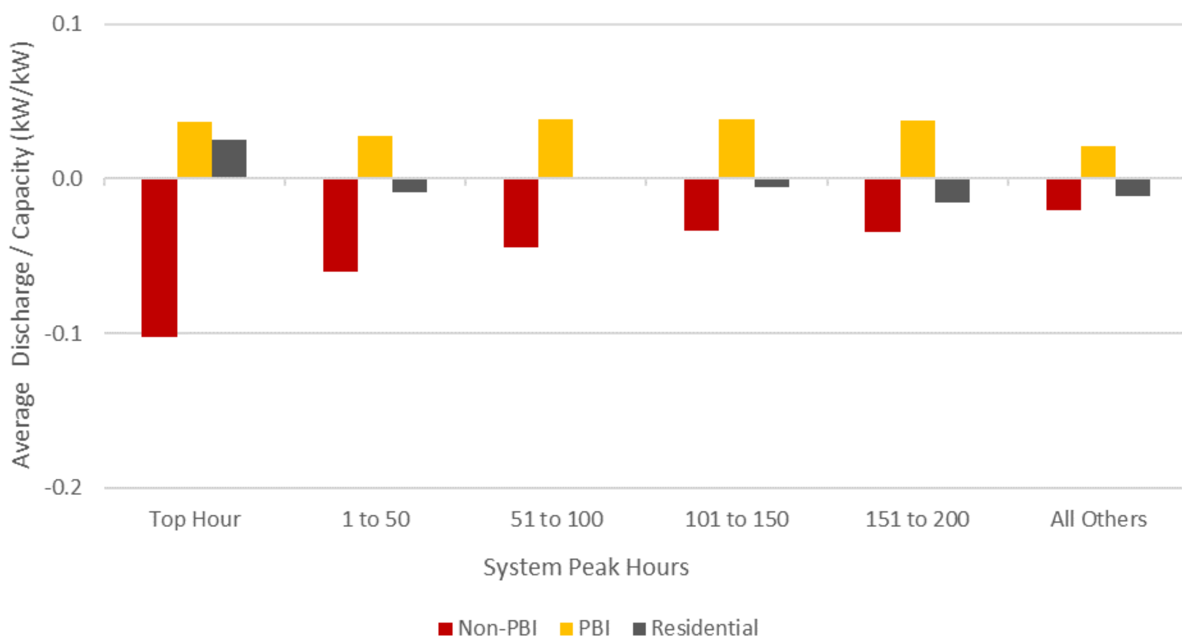
The CAISO and electric utilities have very few programs or incentives that would encourage the use of SGIP AES to provide system benefits. These benefits include avoided generation capacity, transmission and distribution costs. Any benefits that accrue to the system are potentially due to participation in demand response programs, responses to retail rates or are merely coincidental. Storage discharge behavior that is coincident with critical system hours can provide additional benefits beyond customer-specific ones. The evaluation team assessed this potential benefit by quantifying the storage dispatch

[12] This analysis was conducted for only Monday-Friday and excluded weekends.

from our sample of projects and comparing that to the top 200 peak demand hours throughout 2017 for the CAISO system.

Figure 1-12 presents the average net electric energy discharge (kWh per kW rebated capacity) for non-PBI nonresidential, non-PBI residential and PBI projects for different bins of top hours along with the summer average (defined as June through September inclusive). During 2017 the CAISO statewide system load peaked at 49,909 MW on September 1st during the hour from 4 to 5 PM PDT. While PBI projects delivered a CAISO system peak demand reduction approaching 4 MW during the top hour (representing 7% of the 57 MW of rebated PBI capacity), non-PBI nonresidential projects were net consumers of electricity during this hour. Residential projects delivered a CAISO system peak demand reduction approaching 0.05 MW during the top hour. The average impact of SGIP AES projects (PBI and non-PBI) across the CAISO top 200 load hours is a reduction of 2.7 MW and residential projects were net consumers across the top 200 load hours (0.01 MW).

FIGURE 1-12: NET DISCHARGE KWH PER REBATED CAPACITY (KW) DURING CAISO TOP HOURS



1.3.6 Observed Greenhouse Gas Impacts

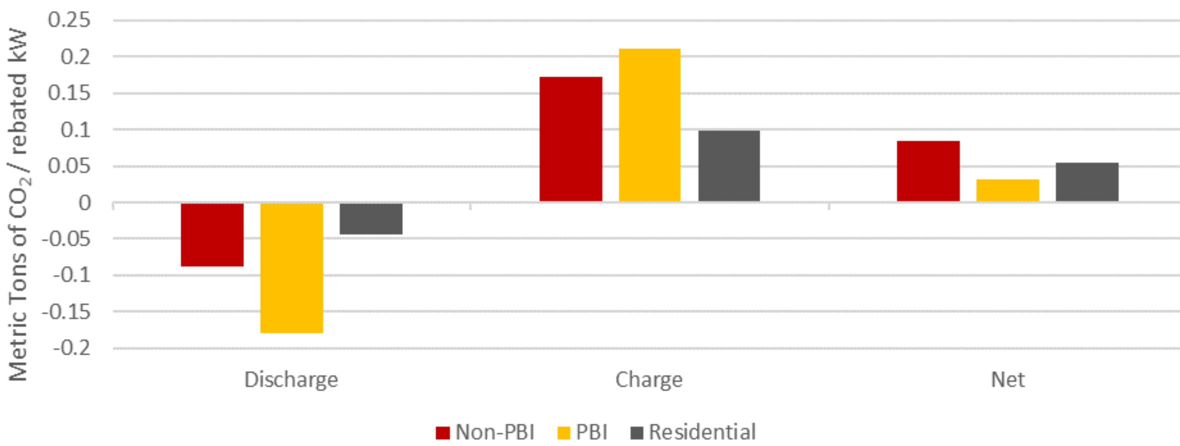
The evaluation team assessed the GHG[13] emissions impact of SGIP AES projects. We first developed a dataset of marginal power plant GHG emission rates for each 15-minute interval in 2017. Using this dataset, GHG emissions were calculated for each customer's load profile with SGIP AES, and without AES. The difference between these two emission profiles (corresponding to the AES charge/discharge kWh) is the GHG impact of SGIP projects. SGIP AES projects increase customer load when they charge, and they decrease load when they discharge. When load is increased, GHG emissions generally increase. Conversely, when load is reduced, GHG emissions are avoided.

For AES projects to reduce GHG emissions, the GHG avoided during storage discharge must be greater than the GHG increase 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. SGIP GHG impacts during 2017 are summarized in Figure 1-13.

GHG impacts for all SGIP AES projects are positive on average, reflecting increased emissions. The magnitude and the sign of GHG impacts is dependent on the timing of AES charging and discharging. During 2017, nonresidential SGIP AES projects increased GHG emissions by 1,436 metric tons of CO_2 and residential SGIP AES projects increased GHG emissions by 116 metric tons of CO_2. Ideal dispatch simulations found that if energy storage systems were to charge/discharge perfectly to reduce customer bills, GHG emissions would increase by approximately 1,200 metric tons of CO_2.

[13] This greenhouse gas emission impact analysis is limited to emissions from grid-scale gas power plants. 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.

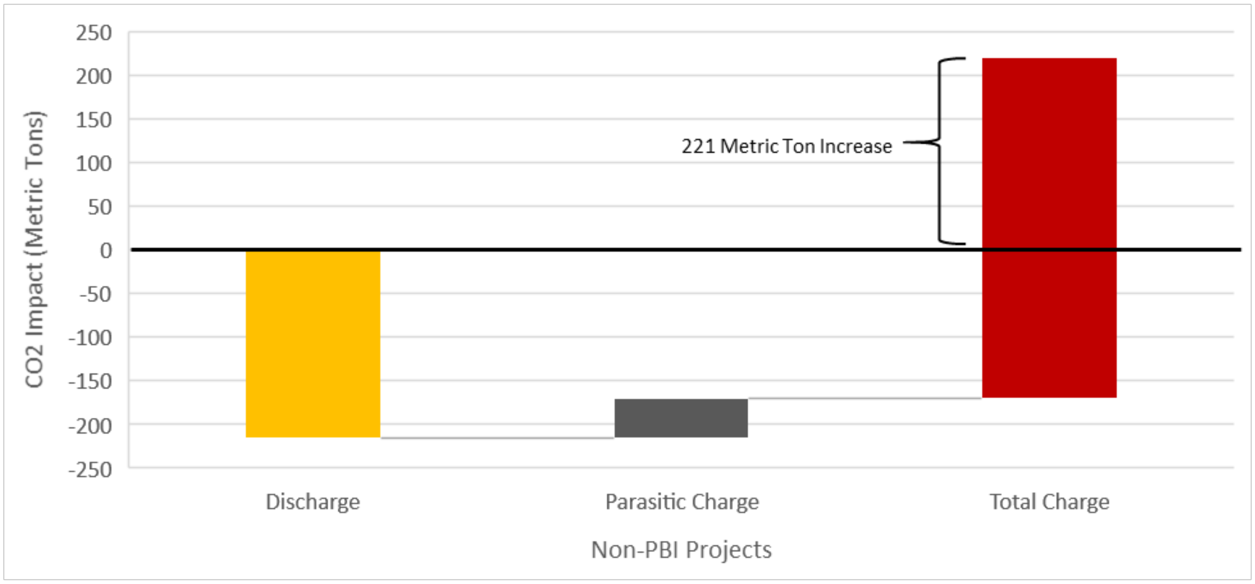
FIGURE 1-13: AVERAGE CO2 EMISSIONS PER SGIP REBATED CAPACITY



The evaluation team estimated the impact that inefficiencies associated with parasitic losses have on the net GHG emissions for nonresidential projects. Figure 1-14 presents the influence these losses have on the overall GHG impacts for our sample of non-PBI nonresidential projects.[14] Parasitic losses account for roughly 10% of the net GHG increase for non-PBI projects. While significant, it is notable that eliminating these parasitic losses is not sufficient to turn the fleet of non-PBI nonresidential projects into GHG reducers. The timing of charge/discharge relative to the grid marginal emissions rate remains the most important factor.

14 The GHG increase in this figure represents the sample-level impact.

FIGURE 1-14: WATERFALL OF TOTAL CO2 IMPACTS FOR NON-PBI NONRESIDENTIAL PROJECTS (INCLUDING PARASITIC INFLUENCE)



1.3.7 Observed Utility Marginal Cost Impacts

The evaluation team assessed the marginal cost impacts for each IOU using the E3 DER Avoided Cost Calculator. Storage system charging results in an increased load and therefore potential cost to the system and discharging results in a benefit, or avoided cost, to the system.

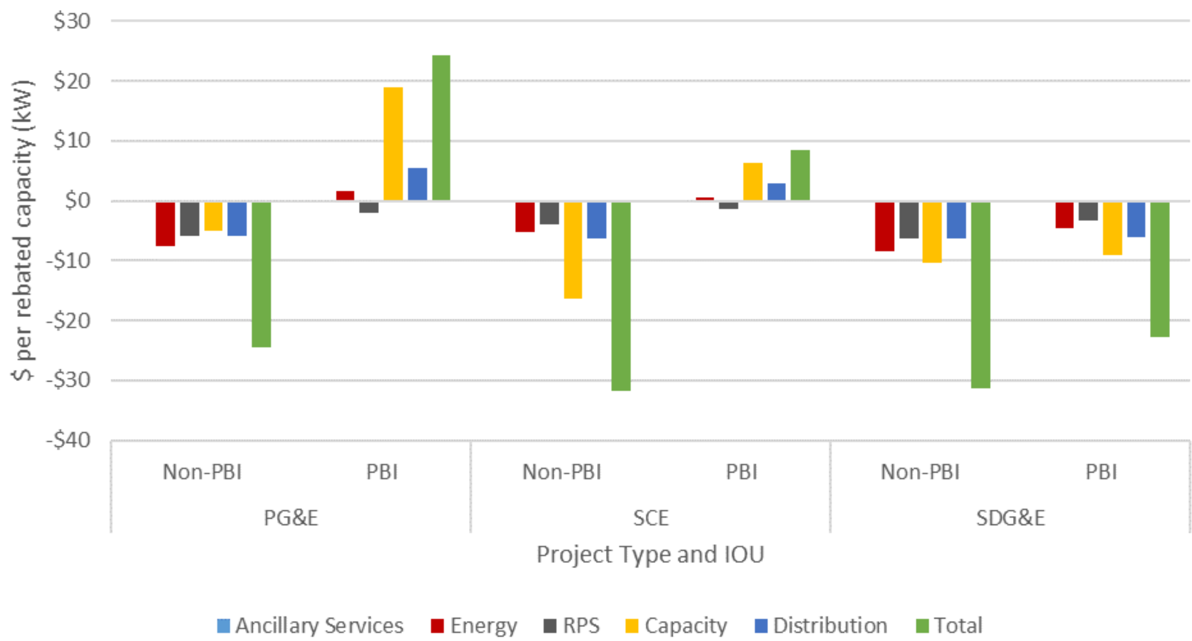
For AES projects to provide a benefit to the grid, the marginal costs “avoided” during storage discharge must be greater than the marginal costs incurred during storage charging. Since AES technologies inherently consume more energy during charging relative to energy discharged, the marginal cost rate 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, transmission, distribution, RPS[15] and ancillary services ($/kWh).

The normalized utility marginal costs are shown in Figure 1-15 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 $2.27 per rebated capacity (kW) and the average marginal cost (-) for non-PBI projects is $29.04 per rebated capacity (kW). The most significant contribution is the marginal cost of delivering energy in each hour, especially the allocation of system, transmission and distribution capacity costs to peak load hours (Section 5). PBI systems were generally

[15] Section 5 provides a detailed definition of RPS and all other marginal costs.

discharging throughout system peak hours and non-PBI projects were charging. The total utility marginal avoided cost estimate for the SGIP AES population in 2017 is $646,693 avoided for PBI projects and $144,719 incurred for non-PBI nonresidential projects. Residential projects also represent a population-level $22,972 incurred cost.

FIGURE 1-15: AVOIDED COSTS $ PER REBATED CAPACITY (KW) BY IOU AND PROJECT TYPE



If the full population of nonresidential SGIP AES projects operating in 2017 were optimized on an hourly basis to minimize system marginal costs with perfect foresight, we estimate that SGIP AES projects would have saved approximately $10 million in system costs in 2017. On the other hand, optimizing dispatch to minimize customer bills would have saved only $1 million in system costs over the year. Optimizing dispatch to minimize carbon dioxide emissions would have yielded a net system benefit of about $2.4 million in 2017. Again, this suggests a disconnect between system costs, CO_2 emissions signals and customer rates.

1.3.8 Simulated Optimal Dispatch Results with Alternative Rates

The system marginal costs used in this study from E3's Avoided Cost Calculator represent the marginal cost of delivering energy in each hour, including an allocation of generation capacity, transmission and distribution costs to peak load hours. As California reaches higher and higher penetrations of renewable generation, these marginal costs are expected to change significantly. The IOUs have proposed to modify their TOU periods to account for excess solar generation during the day and peak net loads that occur later in the evening. As of the time of this writing, the CPUC is still in the process of approving PG&E and SCE's modified TOU periods and has approved SDG&E's proposal, but none of the AES projects in our sample were on this new TOU rate in 2017.

We modeled for each utility the potential impacts of an approved or proposed rate design that better aligns with system costs. We selected one such rate per utility to analyze for nonresidential storage customers:

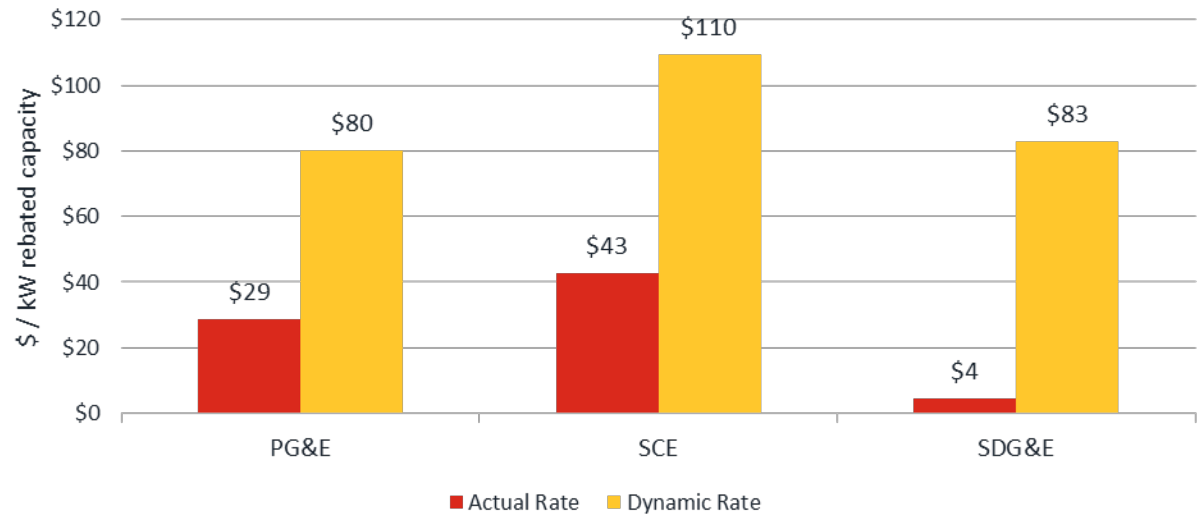
- PG&E has proposed new TOU periods, including an on-peak period from 4 to 7 PM. We selected their revised E19S rate from the various newly-proposed PG&E nonresidential rates;
- SCE's TOU-8 rate has a real-time pricing (RTP) option, which provides a pre-determined hourly price signal that varies based on weather conditions; and
- SDG&E's pilot Grid Integration Rate (GIR) comprises a day-ahead hourly price signal and adders for peak system and distribution capacity hours.

We simulated ideal dispatch of nonresidential energy storage systems under a Customer Dispatch approach (maximizing bill savings) with these more "dynamic" rates on the subset of customers in our sample that were subscribed to an analogous tariff option in 2017. For each utility, we selected as the analogous option the most similar 2017 rate in our AES project sample. PG&E's proposed E19S rate with new TOU periods was matched with the base E19S rate, SCE's TOU-8-RTP was matched with all TOU-8 customers and SDG&E's GIR rate was matched with all ALTOU customers in our sample.

We performed a similar analysis for a small sample (n=15) of PG&E residential projects. We modeled these customers with rate E6 (residential TOU) under current TOU periods and using the proposed 2022 TOU periods (which have an on-peak definition of 4 – 9 pm).

For each utility, the more dynamic rates significantly increase the system benefits from AES projects relative to 2017 rates. For PG&E, AES dispatched to maximize customer bill savings under the existing E19S rate provides system benefits of $29/kW of AES inverter capacity installed (Figure 1-16). Under E19S with the new proposed TOU periods, the avoided cost benefits are $80/kW, an increase of $51/kW or 178%. For both SCE and SDG&E, the rate options models have hourly price signals and the benefits are even larger, at an increase of $67/kW of AES installed for SCE and $79/kW for SDG&E.

FIGURE 1-16: SYSTEM AVOIDED COSTS RESULTING FROM CUSTOMER DISPATCH APPROACH – MORE DYNAMIC RATE COMPARED TO CUSTOMERS' ACTUAL RATE IN 2017



Similarly, using the proposed TOU periods for residential PG&E customers significantly increases the system benefits from AES projects relative to their existing 2017 TOU rate definition.

FIGURE 1-17: SYSTEM AVOIDED COSTS RESULTING FROM OPTIMAL DISPATCH TO MINIMIZE CUSTOMER BILLS, PG&E RESIDENTIAL AES PROJECTS, PG&E E6 RATE WITH EXISTING VS. PROPOSED TOU RATES

1.3.9 Simulated Long Term Integrated Resource Planning Benefit

Using E3's RESOLVE model and two planning scenarios from the CPUC Integrated Resource Planning (IRP) Proceeding, the evaluation team modeled three cases quantifying the benefits that AES can provide in supporting higher penetrations of renewable generation. The two IRP Planning Scenarios are: 1) a scenario that is built and deployed to achieve a statewide electricity sector target of 30 million metric tons of carbon by 2030 (the '30 MMT' scenario), and 2) a scenario that is built and deployed to achieve a statewide electricity sector target of 99 million metric tons of carbon by 2030 (the '99 MMT' scenario). The latter scenario can be thought of as a California grid that is not at all constrained by a GHG target.

Within each of these planning scenarios, we modeled storage projects in three ways: a Low Value case in which AES is not actually dispatched for system benefits, but included simply as a load modifier; a Mid Value case where AES is dispatched for system benefit in RESOLVE but cannot provide operating or contingency reserves; and a High Value case where AES is dispatched for system benefit in RESOLVE and can provide reserves.

Table 1-1 shows the cumulative modeled system benefits for the 2018 – 2030 period from optimal dispatch of the nonresidential SGIP AES projects that were operating in 2017. Note that these results are not directly comparable to the DER Avoided Cost Model approach in Section 5 due to fundamental differences in the model approaches and inputs.

TABLE 1-1: CUMULATIVE SYSTEM BENEFITS FROM NONRESIDENTIAL SGIP PROJECTS OPERATIONAL DURING 2017, NPV 2017$ MILLION, 2018 – 2030

AES Use Case	IRP Planning Scenario	
	99 MMT	30 MMT
Low Value	($0.09)	($1.59)
Mid Value	$15.08	$26.38
High Value	$16.87	$32.41

We find that AES Use Case is a larger driver of savings (and costs) than planning scenario. That is, we find that the value of AES will depend more on how storage is utilized than which system costs California faces in the future. As with the DER Avoided Cost Approach, AES dispatched for customer benefit and not providing any system cost signals increases total system costs, (though only slightly). In the Mid-Value use case, where AES is dispatched for system cost, NPV benefits from 2018 to 2030 range from $15.1 million to $26.4 million, predominantly in variable operating cost savings. Cumulative savings are highest in the High-Value use case, where storage can provide reserves. These benefits range from $16.9 million to $32.4 million.

1.4 CONCLUSIONS AND RECOMMENDATIONS

Behind-the-meter AES projects have the potential to provide myriad benefits to customers, the transmission and distribution system and the environment. The primary purpose of this evaluation was to assess the ability of SGIP AES projects to provide these benefits.

The results of this evaluation are largely consistent with observations from the 2016 SGIP AES evaluation. Our results show that SGIP AES is likely succeeding in providing customer bill reduction. Overall, PBI projects are providing system benefits of coincident peak demand reduction, but non-PBI projects are not. All project types are increasing GHG emissions, and residential projects appear to be providing primarily backup benefits to customers. Below we present key takeaways and conclusions from this 2017 SGIP AES impact evaluation. Where possible, the evaluation team also provides considerations and recommendations.

1.4.1 Rate Design Considerations

SGIP AES projects were found to provide consistent benefits to customers in the form of billed demand reductions or TOU arbitrage. Large PBI projects provided demand reductions during the top CAISO load hours, but smaller non-PBI residential and nonresidential projects did not. Across both size categories, SGIP AES projects increase GHG emissions. Ideal dispatch modeling points to a similar conclusion – given current retail rates and utility marginal costs, storage optimization leads to non-trivial tradeoffs. Optimizing for customer bill savings results in increased emissions and utility marginal costs – this result was verified to some degree by observed impacts which reflect an imperfect case of customer bill saving prioritization. Under existing rates, optimizing for utility marginal costs or GHG emission reductions results in increased customer bills.

These results demonstrate that, under current retail rates, the incentives for customers to dispatch AES to minimize bills are not well aligned with the goals of minimizing utility (and ratepayer) costs or 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. We find that PG&E's new proposed TOU periods, SCE's TOU-8 rate with a real-time pricing option and SDG&E's pilot Grid Integration Rate (GIR) all result in a significant increase in benefits to the system when customers maximize bill reductions.[16] Similarly, customers responding optimally to critical peak pricing and peak day pricing tariffs to minimize their bills are shown to significantly increase avoided costs.

A few further observations may be valuable in designing rates for storage that achieve better alignment with system costs and GHGs. First, these two signals – system costs and GHGs – are far from perfectly

[16] It's important to note that not all customers are eligible for these rates and GIR is a pilot program.

correlated. However, given the relatively small number of hours that contribute the highest system costs each year, it may be possible to design incentives that co-optimize somewhat for the two objectives. This is a current focus for the CPUC's GHG Working Group. Second, it is worth considering the sometime competing price signals provided by energy rates and non-coincident demand charges. Simulated dispatch analysis showed that while some nonresidential projects would devote most of their discharging to on-peak hours when minimizing their bill, only ten customers would discharge entirely on-peak and around half the projects would discharge less than 50% of their energy on-peak. The average energy discharged on-peak under ideal dispatch is 60%; the average energy discharged at mid-peak under ideal dispatch is 21%. The implication of this finding is that TOU rates paired with non-coincident demand charges can undermine the extent to which the timing of customers' load can be influenced. While non-coincident 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, non-coincident 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.

1.4.2 Round Trip Efficiencies, Parasitic Loads and Greenhouse Gas Emissions

The mean observed RTE was 51% for non-PBI nonresidential projects, 38% for non-PBI residential projects and 81% for PBI projects over the 2017 evaluation period. The 2016 SGIP Handbook requires a first-year RTE of 69.6% and a ten-year lifetime average RTE of 66.5% for program eligibility. PBI projects met this requirement during the evaluation period but non-PBI projects (both residential and nonresidential) did not. In this analysis, RTEs were calculated by dividing the total energy output of a battery by its total energy input over the course of the evaluation period. By calculating the RTE across several months, we inherently capture not just the "single cycle" RTE (the efficiency with which a battery converts AC energy to DC and back to AC) but also any parasitic loads incurred when the battery is idle.

There is a strong relationship between utilization (measured as 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, GHG emissions would remain positive. In other words, increasing capacity factor for the sake of increasing RTE alone will likely not turn SGIP AES projects into net GHG reducers.

On December 29, 2017 the CPUC issued an Assigned Commissioner's Ruling establishing the SGIP GHG Working Group to develop recommended changes to the SGIP to improve GHG emission reductions from energy storage systems. Among the GHG Working Group's recommendations was the development of a GHG signal that storage systems can "follow" to improve the timing of charge/discharge. Our modeling shows that any SGIP storage system following a GHG signal can reduce GHG emissions but likely at the expense of customer bill savings.

1.4.3 Demand Response Participation, Wholesale Markets and Grid Integration

Solutions like a GHG signal could potentially bridge the gap between projects on current retail rates and future applicants subject to new, dynamic rates. Program Administrators should also consider that wholesale electricity pricing (e.g., CAISO NP15 and SP15 locational marginal prices) already contain much of the information required to estimate marginal grid emissions. When locational marginal prices are high, utility marginal costs and marginal emissions tend to be high as well. Programs that allow SGIP AES systems access to these markets may be able to produce system benefits.

SGIP projects currently participate in several demand response programs including several that are tied to the CAISO wholesale market like the Distributed Resource Auction Mechanism (DRAM). We observed that SGIP AES projects can successfully participate in these programs and provide real demand reductions when called upon. However, these programs have yet to see significant widespread adoption, and event days are relatively infrequent. The sample of AES projects enrolled in DRAM responded to events on 9 days for PG&E, 5 days for SCE and 82 days for SDG&E (between 1% and 22% of all days). The infrequency with which these events are called limits the ability of storage systems to provide system benefits and likely GHG benefits as well. The CPUC should consider ways to increase the availability of DR programs to SGIP AES participants and the PAs should investigate ways to increase participation of SGIP AES in DR programs.

In general, we find that programs that provide signals at the hourly or sub-hourly level like DRAM, Capacity Bidding Program (CBP) or PG&E's Supply Side Pilot (SSP) are more effective at incentivizing storage behavior than broader programs like Peak Day Pricing (PDP). We also observed significant "snap-back" effect on many DR programs which can erode the system and environmental benefits of the original signal.

Considerations for Integrated Resource Planning

We performed a forward-looking analysis to consider the potential value of storage in integrated resource planning of California's grid through 2030. E3 performed this analysis using their RESOLVE model and cases developed for California's IRP process. The analysis found that if SGIP AES is modeled strictly as a load modifier (a proxy for business-as-usual), it is forecasted to produce a slight increase in overall system costs over the 2018 – 2030 horizon. However, in a carbon-constrained future where the AES is dispatched to minimize system costs and able to provide contingency and operating reserves, the electricity system could see cumulative fixed and variable cost savings of over $30 Million. This demonstrates that significant value will be left on the table if SGIP AES is not available to be dispatched for system-level benefits by grid operators, market mechanisms or dynamic rates. In addition to merely generating energy, system-level resources must also be operated to provide reserves in the case of sudden outages, congestion or changes in electricity demand. Our analysis suggests that these reserves are a significant unrealized benefit category that could reduce the fixed capital investment required by utilities to provide sufficient flexibility for higher renewable penetration.

We recommend that the CPUC and SGIP Program Administrators consider ways of promoting participation in demand response programs, CAISO energy and ancillary service markets and the regional Energy Imbalance Market (EIM) to promote the type of reserve capacity valued so highly by the RESOLVE model. SGIP Program Administrators or the CPUC could also develop program requirements to ensure that AES can reliably count towards flexible RA and provide operating reserves to reduce planning and procurement costs for the flexible resources needed to achieve renewable and GHG targets for the electric sector. Currently, because SGIP storage is a behind-the-meter resource, it is not relied upon by system operators as a means of providing reserves. Although storage would in theory be capable of functioning to assist system operators, its potential value is left unrealized because there is no contract or mechanism in place to assure this participation. SGIP participants being subject to contracts like DR participants, in which their load could be increased or decreased at the request of system operators, could help realize this potential.

1.4.4 Residential Projects

All residential projects in our sample were found to be idle for a considerable portion of the year and served to provide backup power. When not idle or providing backup, these systems engaged in charge/discharge cycling to meet the SGIP's requirement to fully discharge 52 times per year (for systems subject to the appropriate affidavit). This behavior often led to discharging during PV generation and charging during the early evening when residential customers typically experience their non-coincident peak demand.

Residential customers do not currently experience demand charges, and currently few participate in TOU rates. No residential projects in our sample are believed to participate in demand response programs that energy storage could support. Most residential customers in our sample are on tiered, non-TOU volumetric retail energy rates, and consequently present few opportunities for cost-effective storage dispatch. Residential energy storage customer bills likely increased due to increased energy consumption from the storage system and storage dispatch behavior contributed to an increase in emissions. The only tangible benefit of these systems comes in providing backup – the evaluation team was not able to quantify if/when residential energy storage systems provided backup services.

Going forward we expect a new generation of energy storage systems will be able to operate in different modes beyond backup and cycling. Performing PV self-consumption and afternoon discharging may not provide any benefits to customers on volumetric tiered rates but would likely provide environmental and utility marginal cost benefits. Furthermore, participation in ancillary services or demand response programs would create financial opportunities for residential storage dispatch where there currently are none.

1.4.5 AES Co-Located with Renewable Generation Systems

SGIP AES projects represented a combination of standalone projects and projects either co-located or paired directly with solar PV systems. As with the 2016 evaluation, we found that during 2017 there was no discernable difference in performance between AES systems co-located with PV and standalone AES projects. The data indicated that AES projects paired with PV were not prioritizing charging from PV. This suggests that storage developers do not see value in maximizing PV self-consumption given current retail rates and Net-Energy Metering (NEM) tariffs. For systems that were co-located with PV during this evaluation, we found that the PV system was almost always installed well before the storage system, often having received an incentive from the California Solar Initiative (CSI) General Market program.

Going forward the Program Administrators have modified SGIP eligibility rules to encourage AES charging from PV. Projects that are shown to charge from PV will have priority in a potential lottery. This new requirement will only apply to projects rebated during PY 2017 so these projects will likely first be subject to evaluation during the 2018 SGIP storage evaluation report. Furthermore, eligibility for investment tax credits might promote increased pairing of SGIP AES projects with PV or other renewable generators. Looking at the SGIP queue and projects already completed through the first half of 2018, we see a significant increase in residential projects. Most of the forthcoming residential projects appear to be paired with PV. Until these projects are evaluated, it's unclear whether these represent new PV installations or existing PV with retrofitted energy storage.

As the SGIP continues to promote PV paired with storage, questions about program attribution effects naturally arise. If the SGIP is facilitating integration of PV that would otherwise not have been installed, then there may be some spillover effects that may be quantified as program benefits. Quantification of these program externalities and market effects in program impact evaluation is known as net-to-gross analysis. To date, a vetted methodology for quantifying these effects for SGIP technologies does not exist. We recommend that the CPUC and the PAs pursue development of a SGIP net-to-gross methodology ahead of the 2018 SGIP Impact Evaluation Report. This methodology should be publicly vetted and agreed upon by multiple stakeholders, and then implemented in future SGIP impact evaluation reports.

1.4.6 Data Availability, Timing and Quality

The evaluation team received data from several project developers representing hundreds of SGIP energy storage projects. In general, we found that data quality and availability has improved relative to the 2016 SGIP Energy Storage Impact Evaluation Report. However, certain data quality issues provided significant hurdles for the evaluation team to analyze impacts and report results. We provide the following recommendations to improve the quality of future SGIP energy storage impact reports:

- Looking ahead to 2018, we anticipate data collection will be required from numerous small residential energy storage developers. Obtaining data from multiple small sources is always more challenging than interacting with a single entity. Where possible, we recommend that the PAs clearly communicate to applicants these future evaluation needs so no parties are caught off guard with a data request.

- PAs should evaluate the current processes for ensuring that SGIP AES projects are collecting data of sufficient quality for impact evaluation purposes. This evaluation report relied heavily on additional metering for M&E purposes to fill certain strata, particularly among residential projects.

- If the CPUC and the PAs are interested in understanding influence of parasitic loads, then they should consider specifying minimum meter accuracy requirements. There were several instances where data provided from storage developers were not able to capture parasitic loads. Instead these data reported zero energy during idle periods. The PAs should weigh the potential benefits of understanding parasitic loads against the potential increased metering cost burden.

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. Energy storage projects paired with renewables, energy storage projects located in the Los Angeles Department of Water and Power (LADWP) service territory and energy storage projects located in Southern California Edison's West LA Local Capacity Area will be given priority in the lottery.

The SGIP has authorized incentive collections totaling $501,735,000. 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 2016, the incentive level for AES had changed to $1.31 / Watt.

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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_2009SGIPHandbook.pdf?MOD=AJPERES

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

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

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[5] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. Passage of Senate Bill (SB) 412[6] (Kehoe, October 11, 2009) refocused the SGIP toward greenhouse gas (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 their 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(I)(6), quantify any contribution of energy storage projects to grid services where that storage substituted for and replaced planned investment into grid services.

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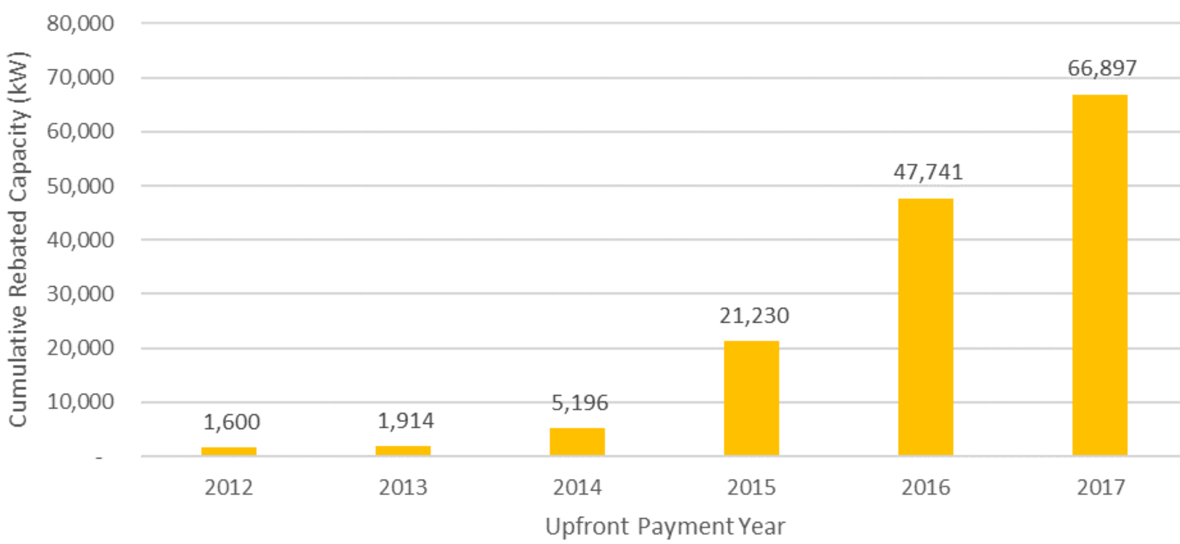
5 http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

6 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, 2017. Figure 2-1 shows growth in SGIP energy storage rebated capacity[7] over time. By the end of 2017, the SGIP had provided incentives to 828 advanced energy storage projects representing almost 67 MW of rebated capacity. SGIP incentives are available for electrochemical, mechanical and thermal energy storage. As of December 31, 2017, all SGIP rebated storage projects were electrochemical (battery) energy storage technologies.

FIGURE 2-1: SGIP STORAGE CUMULATIVE REBATED CAPACITY BY UPFRONT PAYMENT DATE



Energy storage projects saw significant growth during program years 2014 and 2015, adding approximately 46 MW of rebated capacity. Figure 2-2 shows growth in storage rebated capacity by program year (the year a project applied to the SGIP).[8]

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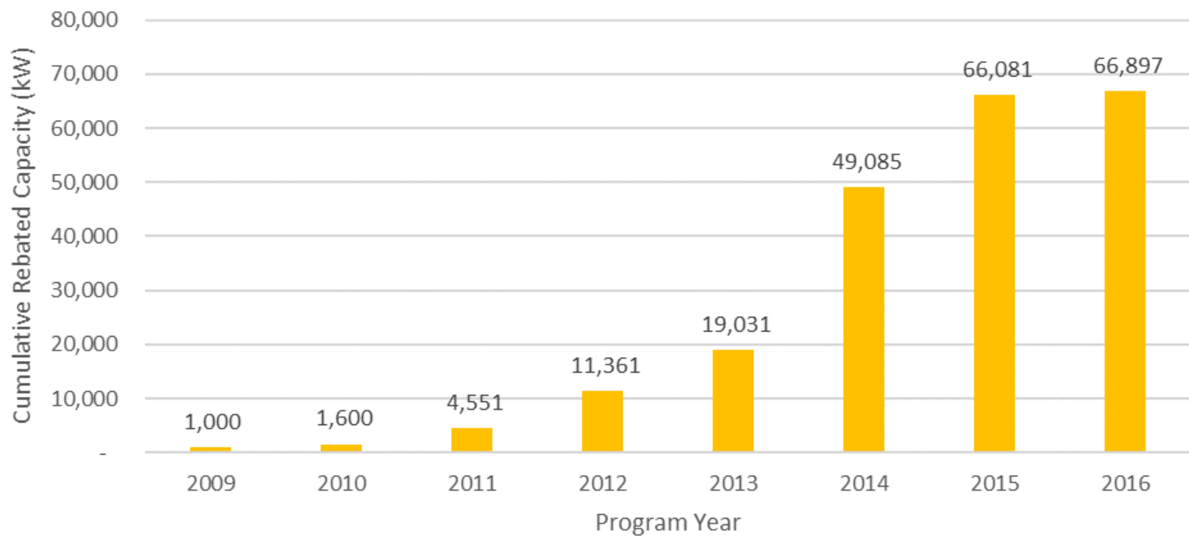
[7] As of PY 2017, rebated capacity is defined as the average discharge power rating over a two-hour period. Throughout this report, we reference projects by their SGIP rebated capacity with an understanding that inverter sizes can be up to 2x greater than the SGIP rebated capacity value.

[8] It's important to note the difference between upfront payment year and program year. While many projects received upfront payments in 2017, all projects applied to the SGIP prior to that year. A project may have applied in PY 2016 and received their upfront payment during calendar year 2017. All projects in the 2017 population applied to the SGIP prior to 2017. This is due to the installation, interconnection and administrative timelines associated with building energy storage systems.

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



Most SGIP storage projects applied during PY 2011 – 2015, after SB 412 had introduced Performance Based Incentive (PBI) payment rules to the SGIP. The focus of this evaluation is on the projects rebated post-SB 412 rules (97% of storage rebated capacity). Table 2-2 summarizes the total number of projects, rebated capacity and incentive amounts reserved[9] by PA. PG&E has the most number of projects, followed by SCE and CSE. PG&E and SCE represent a roughly equal share of rebated capacity (kW). As of December 31, 2017, only four projects were completed in SCG's service territory.

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	315	25,051	$52,937,397
Southern California Edison	292	25,310	$44,229,336
Southern California Gas Company	4	654	$1,304,808
Center for Sustainable Energy	217	15,882	$26,104,455
Total	***828***	***66,897***	***$124,575,996***

SGIP storage projects are installed at customer locations served by electric-IOUs and/or gas-IOUs. When the customer 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

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

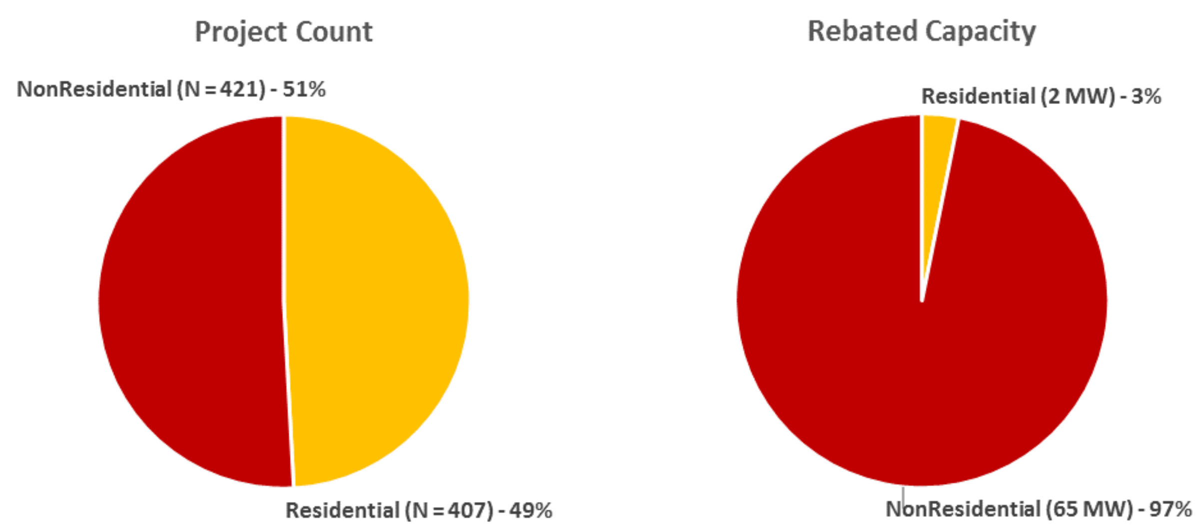
PAs with energy storage projects installed at non-IOU electric customer locations. Most (791 of 828) SGIP energy storage projects are installed at electric-IOU customer locations.

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	281	34	24,898	153
Southern California Edison	292	-	25,310	-
Southern California Gas Company	1	3	600	54
Center for Sustainable Energy	217	-	15,882	-
Total	***791***	***37***	***66,690***	***207***

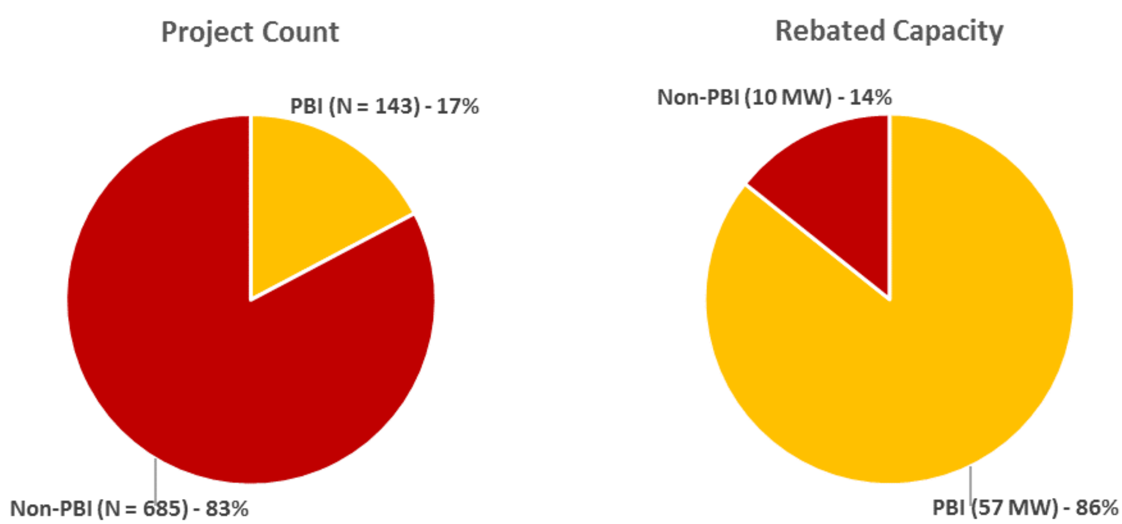
SGIP storage projects are installed at both residential and nonresidential customer sites. Figure 2-3 shows the breakdown in sector by project count and rebated capacity. While the number of projects installed across the sectors is almost equal, most of the SGIP storage rebated capacity (97%) is installed at nonresidential customer sites. Nonresidential projects are almost always larger and therefore have a larger contribution to total program impacts.

FIGURE 2-3: SGIP STORAGE PROJECT COUNT AND REBATED CAPACITY BY HOST CUSTOMER SECTOR



Projects are further split into two categories: 1) PBI[10] 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 143 PBI projects in the SGIP population representing roughly 57 MW of the 67 MW total SGIP storage rebated capacity. All PBI projects are installed at nonresidential customer locations. Figure 2-4 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.

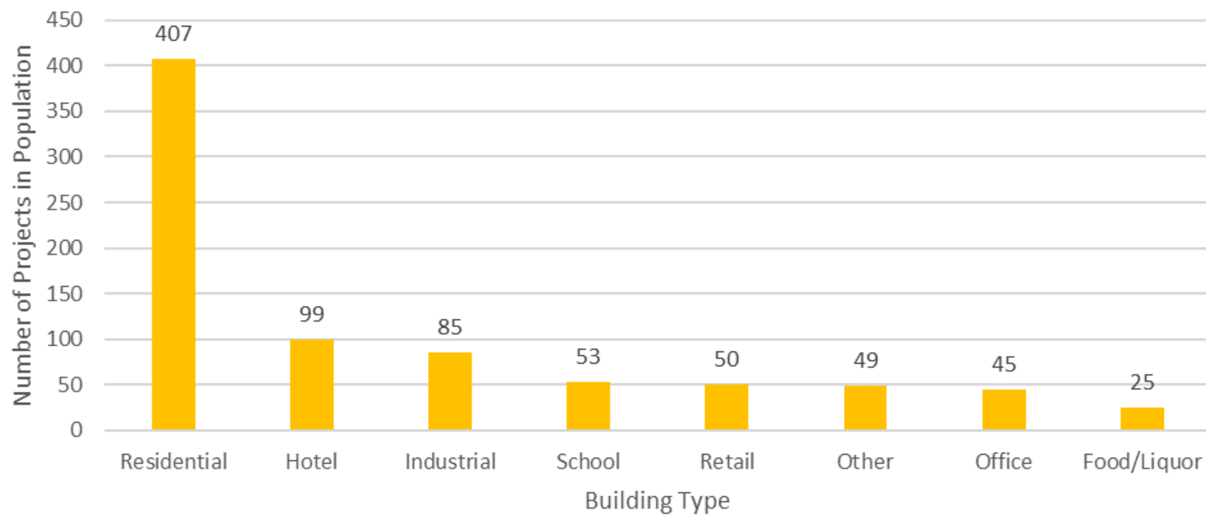
FIGURE 2-4: ENERGY STORAGE PROJECTS BY PBI/NON-PBI CLASSIFICATION



Energy storage projects are installed at a variety of building types. Figure 2-5 summarizes the distribution of building types in the SGIP energy storage population by project count.

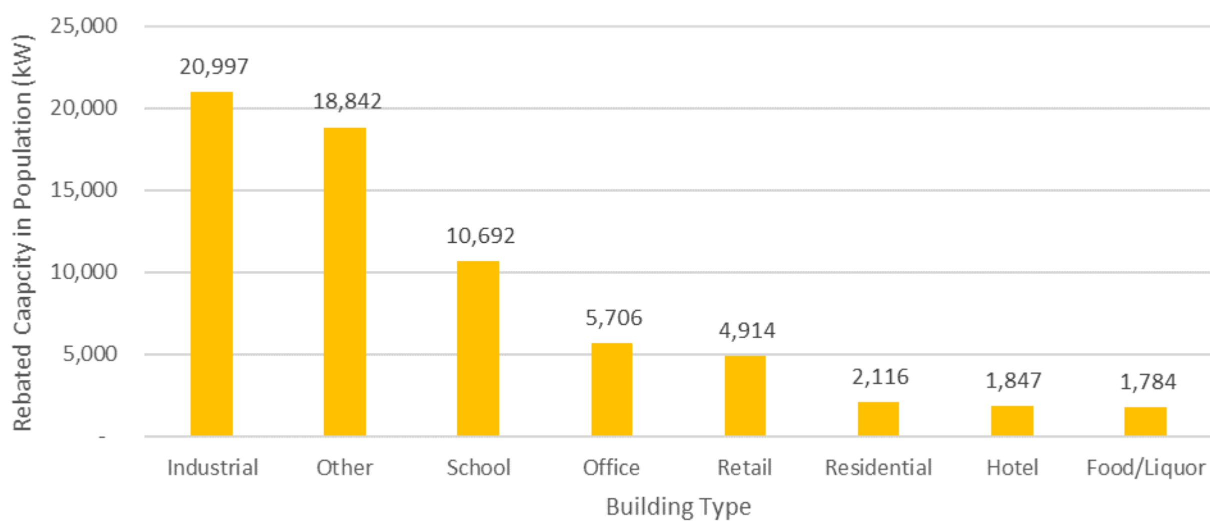
10 *2016 Self-Generation Incentive Program Handbook*, 2016, available at https://www.selfgenca.com/home/resources/

FIGURE 2-5: DISTRIBUTION OF BUILDING TYPES WITH ENERGY STORAGE BY PROJECT COUNT



Most energy storage projects in the population are installed in residential buildings (407 of 828), followed by hotels (99), industrial facilities (85), schools (53) and retail (50). However, residential energy storage projects are relatively small (approximately 5 kW rebated capacity each on average) compared to nonresidential energy storage projects (approximately 150 kW rebated capacity each, on average). Figure 2-6 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 proportion of projects installed in the residential sector is much smaller on a capacity basis.

FIGURE 2-6: 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, 2017. For projects that became operational during 2017, 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, environmental or renewable integration benefits. This analysis is performed using Energy + Environmental Economics' (E3's) RESTORE Storage Dispatch Optimization model,[11] 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.

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;

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

- 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

We employ two distinct approaches to quantify the potential benefits of energy storage, if it were optimally dispatched with perfect foresight in 2017. The first is a short-term marginal cost approach using E3's RESTORE optimal dispatch model, populated with 2017 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.[12]

The RESTORE analysis aims to quantify the *maximum* benefits SGIP storage projects could have potentially achieved in 2017, *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 marginal carbon dioxide emissions for the associated customer.

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

Additional detail on this methodology is provided in Section 5.2.

We also sought to quantify the potential value AES could provide to California's electricity system in the long term. For this purpose, we used E3's Renewable Energy Solutions (RESOLVE) model.[13] This approach is being used in the CPUC's Integrated Resource Planning Proceeding. To bound the potential system value of storage through 2030, we model two IRP planning scenarios:

- A scenario that is built and deployed to achieve a statewide electricity sector emission target of 30 million metric tons of carbon by 2030 ('the 30 MMT' scenario)
- A scenario that is built and deployed to achieve a statewide electricity sector emission target of 99 million metric tons of carbon by 2030 ('the 99 MMT' scenario). This scenario can be thought of as a California grid that is not at all constrained by a greenhouse gas (GHG) emission target

We also model three Use Cases for storage in RESOLVE:

- A Low Value AES use case, which models AES as a load modifier
- A Mid-Value AES use case, in which AES is dispatched to minimize system costs through 2030, but not allowed to provide operating reserves (e.g., frequency regulation, spinning reserves, energy reserves)
- A High-Value AES Use Case, in which AES is dispatched as in the Mid-Value case, but also able to provide operating reserves

Additional details on this methodology are provided in Section 6.

2.3 REPORT ORGANIZATION

This report is organized into six 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 to develop population impacts.
- Section 4 characterizes the metered sample and presents the observed program impacts.

13 https://www.ethree.com/tools/resolve-renewable-energy-solutions-model/

- Section 5 summarizes potential storage benefits in the short-term using ideal dispatch simulations.
- Section 6 quantifies potential renewable integration benefits in the long-term.
- 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.

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 2017 POPULATION OF AES PROJECTS

As presented in Section 2, by the end of 2017, the SGIP provided incentives for 828 AES projects representing roughly 67 MW of rebated capacity. This represents a 41% increase in total rebated capacity from the prior calendar year.

Figure 3-1 presents the change in SGIP rebated capacity from 2016 to 2017 by sector (residential versus nonresidential) and incentive payment mechanism (5-year PBI versus 100% upfront payment). One hundred and fourteen new projects received upfront payments during 2017 with a net increase in total capacity, as shown (and project count) for each of the project types shown below. Nonresidential PBI projects represent the most significant increase in SGIP rebated capacity – a 46% increase from 2016 to 2017. Population level nonresidential non-PBI and residential projects have also increased by 13% and 9%, respectively.

FIGURE 3-1: SGIP STORAGE CHANGE IN REBATED CAPACITY FROM 2016 TO 2017 BY SECTOR AND PAYMENT TYPE

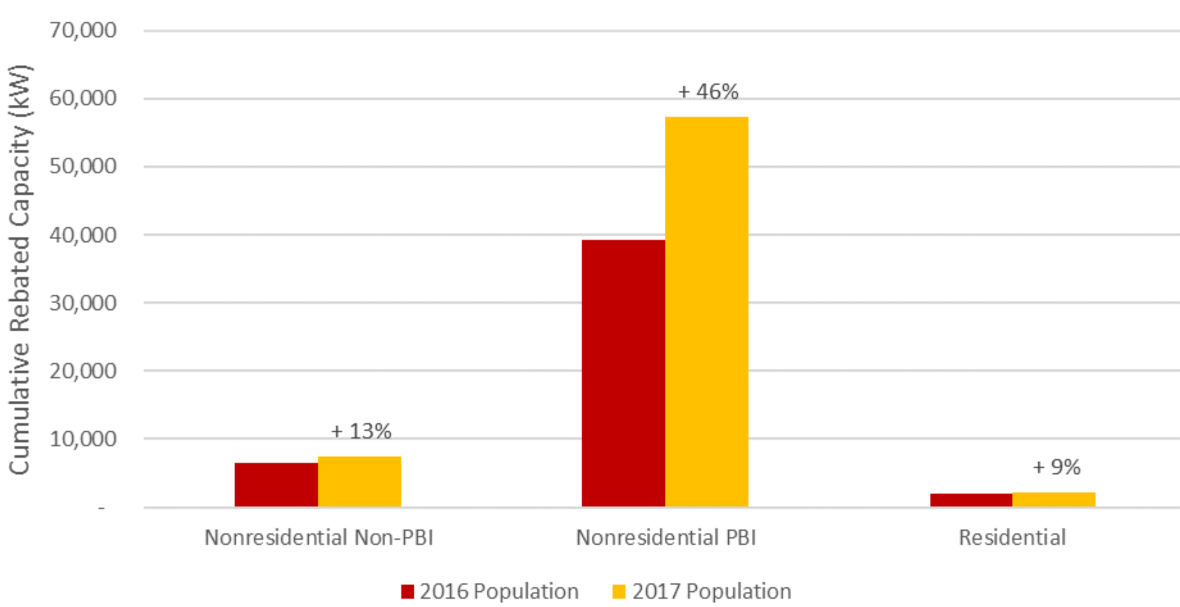


Table 3-1 presents the total number of projects in the 2017 population along with the total capacity for each customer segment and storage category, by program administrator (PA). As discussed in Section 2, the 2017 population comprised 421 nonresidential and 407 residential projects (828 total). Of the 421 nonresidential projects, 278 are non-PBI projects (< 30 kW) and 143 are PBI projects. Nonresidential projects (64.8 MW) account for a large majority of the total 66.9 MW. The most significant contribution of capacity comes from nonresidential PBI projects (57.3 MW).

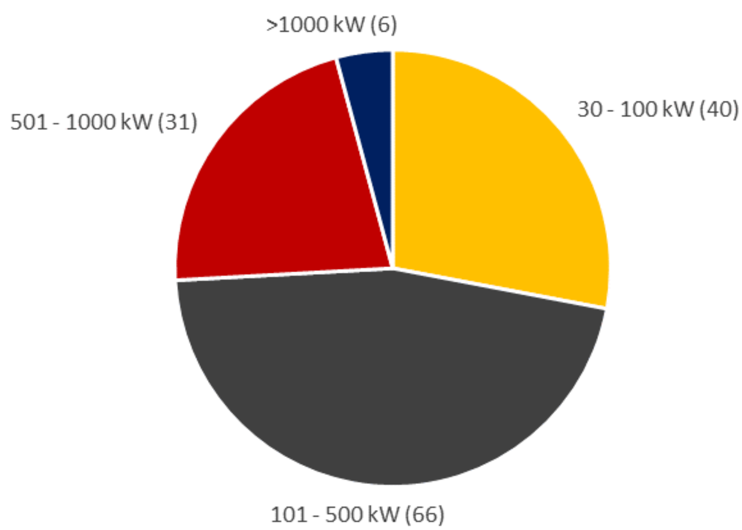
TABLE 3-1: 2017 SGIP POPULATION BY PA, CUSTOMER SECTOR AND INCENTIVE PAYMENT RULE

PA	Customer Segment	Project Count	% Project Count	Rebated Capacity (kW)	% Rebated Capacity (kW)
PG&E	Nonresidential Non-PBI	100	32%	3,071	12%
	PBI	42	13%	21,088	84%
	Residential	173	55%	892	4%
	All	**315**		**25,051**	
SCE	Nonresidential Non-PBI	101	35%	2,161	9%
	PBI	52	18%	22,434	89%
	Residential	139	48%	714	3%
	All	**292**		**25,310**	
CSE	Nonresidential Non-PBI	74	34%	1,568	10%
	PBI	49	23%	13,818	87%
	Residential	94	43%	496	3%
	All	**217**		**15,882**	
SCG	Nonresidential Non-PBI	3	75%	640	98%
	Residential	1	25%	14	2%
	All	**4**		**654**	
Total	**Nonresidential Non-PBI**	**278**	**34%**	**7,441**	**11%**
	PBI	**143**	**17%**	**57,341**	**86%**
	Residential	**407**	**49%**	**2,116**	**3%**
	All	**828**		**66,897**	

3.1.1 PBI Population

The PBI population includes 143 AES projects online during 2017. 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 PAs. Figure 3-2 presents the distribution of PBI project counts by capacity bin. Most PBI projects (66) fall within the 100 to 500 kW SGIP rated capacity bin, followed by 30 to 100 kW systems (40) and 500 to 1,000 kW systems (31). Six projects are greater than 1,000 kW, the largest being 2,600 kW.

FIGURE 3-2: 2017 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 3-3 presents the distribution of building types representing the 2017 AES PBI projects (by project count) and Figure 3-4 presents the distribution of building types by rebated capacity. Industrial facilities and schools represent the greater share of total project count at 29%, followed by other[1] (17%) and offices (11%). However, when examining the distribution by rebated capacity, industrial facilities represent the most significant share at 43%.

FIGURE 3-3: 2017 SGIP PBI POPULATION BY BUILDING TYPE AND PROJECT COUNT

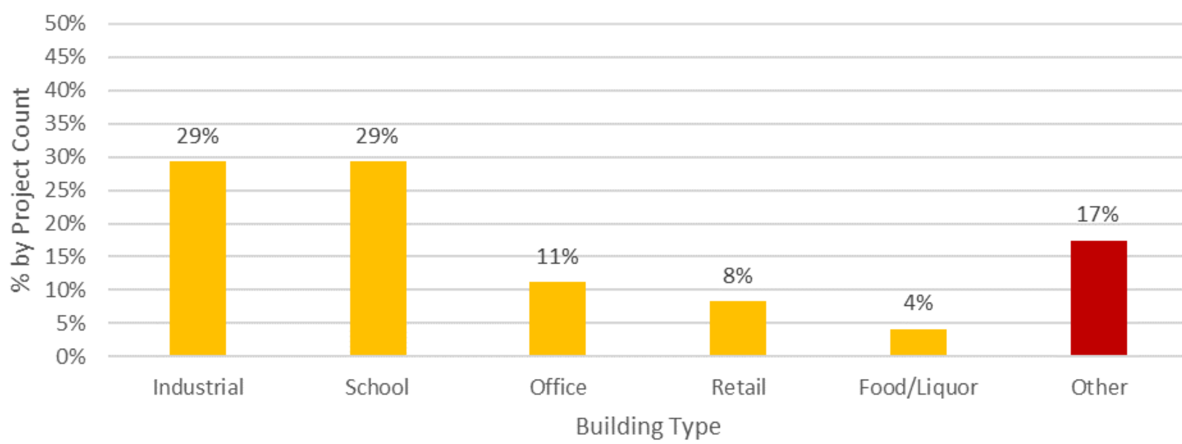
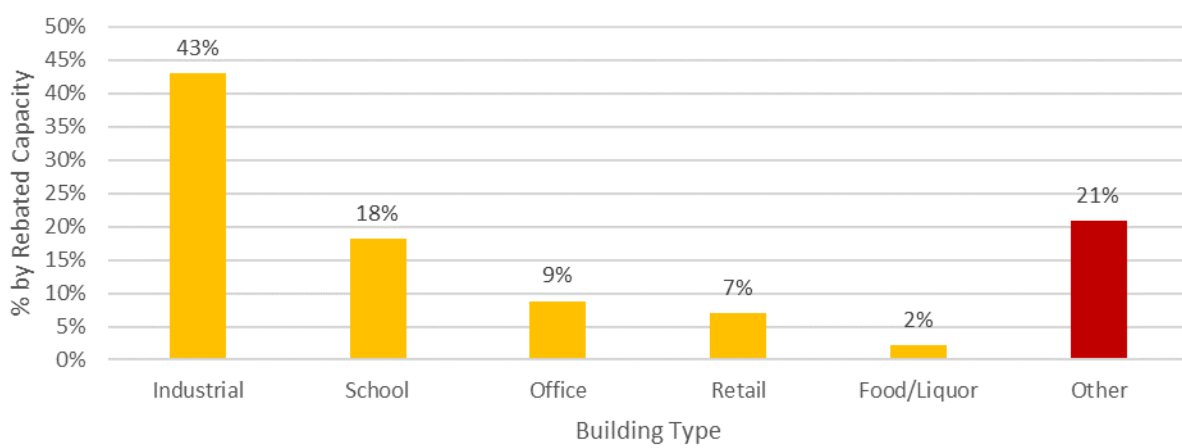


FIGURE 3-4: 2017 SGIP PBI POPULATION BY BUILDING TYPE AND REBATED CAPACITY



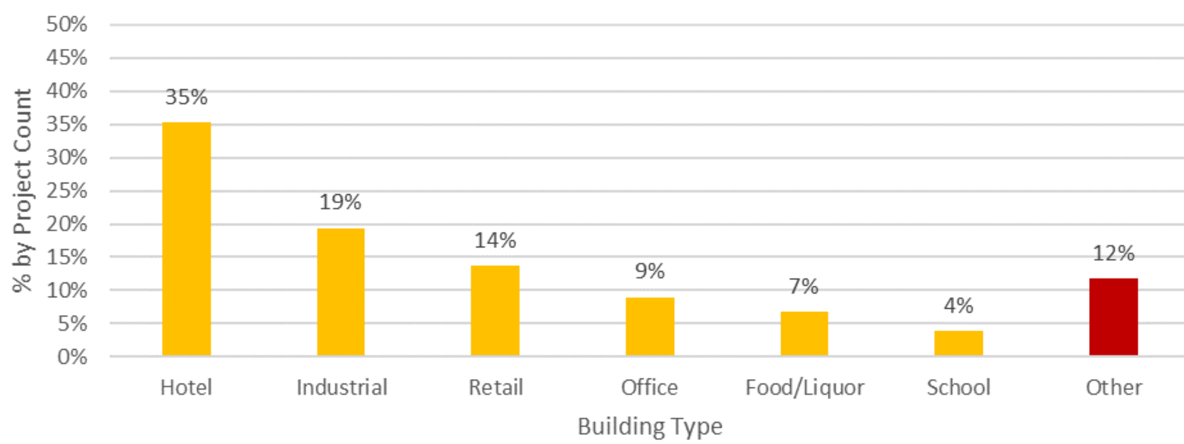
[1] This category includes warehouses, health care facilities and other miscellaneous building types.

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.

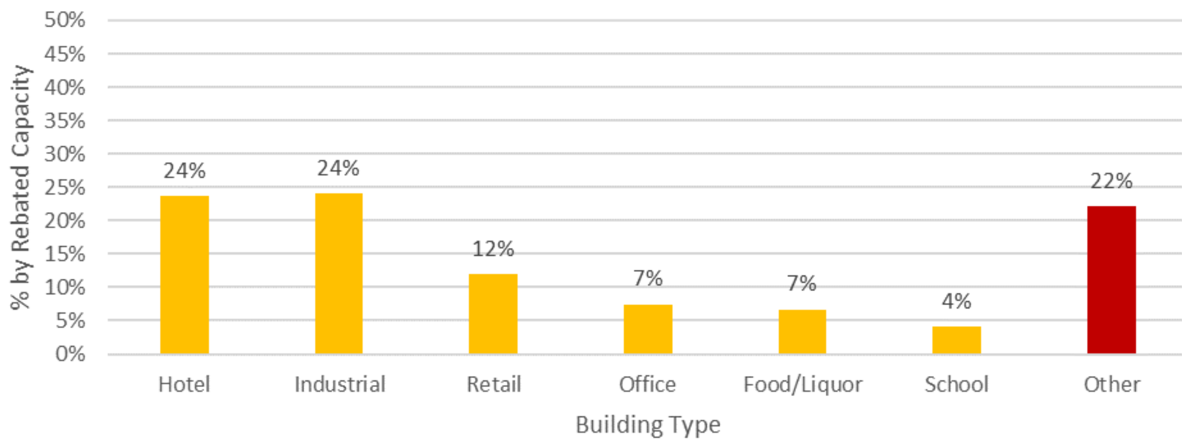
Figure 3-5 presents the distribution of building types representing the 2017 AES non-PBI projects (by project count) and Figure 3-6 presents the distribution of building types by rebated capacity. Hotels represent the greater share of total project count at 35%, followed by industrial facilities (19%) and retail (14%). However, when examining the distribution by rebated capacity, hotels represent a less significant share at 24%. 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.

FIGURE 3-5: 2017 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 3-6: 2017 SGIP NON-PBI NONRESIDENTIAL POPULATION BY BUILDING TYPE AND REBATED CAPACITY



3.1.3 Residential Non-PBI

Residential projects comprise 407 of the 828 SGIP AES projects subject to evaluation for 2017. This sector represents roughly 49% of the 2017 population by project count. These systems are smaller than systems installed within commercial or industrial facilities. Of the 407 systems represented in the population, 94% are within 4.5 and 5 kW in rebated capacity. Therefore, their contribution to total population rebated capacity (3%) is much less than the 49% representation by project count.

3.2 SGIP 2017 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 57 MW of the SGIP AES program capacity of 67 MW. The 57 MW represent a 46% increase in SGIP rebated capacity from 2016. There are 143 PBI projects subject to measurement and verification, which represents a 75% increase by project count from 2016.

For the 2016 AES impact study, the evaluation team collected data from 78 of the 83 PBI storage projects in the SGIP. We did not employ any sampling strategy to develop impacts from these projects, but rather attempted a census of all projects. The evaluation team utilized the same approach for 2017. 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.

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 analysis sample represents 136 of the 143 projects subject to evaluation in 2017 which accounts for roughly 95% of all PBI projects by project count and 94% by rebated capacity.

While it was our intention to conduct measurement and verification on all 2017 PBI projects, we uncovered some data limitation and data quality issues which precluded a rigorous evaluation of all projects in the population.

TABLE 3-2: 2017 SGIP PBI POPULATION AND SAMPLE DISPOSITION BY PA

Payment Type	PA	Project Count			Rebated Capacity (kW)		
		N	n	% in Sample	N	n	% in Sample
PBI	PG&E	42	42	100%	21,088	21,088	100%
	SCE	52	47	90%	22,434	21,786	97%
	CSE	49	47	96%	13,818	11,118	80%
	All	**143**	**136**	**95%**	**57,341**	**53,993**	**94%**

3.2.2 Non-PBI Nonresidential Sample Disposition

Nonresidential non-PBI projects represent roughly 7 MW of the SGIP AES program capacity of 67 MW. The 7 MW represent a 13% increase in rated capacity within SGIP from 2016. There are 288 non-PBI nonresidential projects subject to measurement and verification which represents a 13% increase by project count from 2016.

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. In 2016, the evaluation team made efforts to contact and request metered data from most developers with relative success. Ultimately, we evaluated 181 of the 245 projects in the population for 2016, which represented roughly 55% of rebated capacity within the non-PBI nonresidential category. While the evaluation team attempted to secure metered data for the majority of the 2016 SGIP population, we did not develop a dedicated sampling strategy. We reviewed the data provided by the project developers and developed impacts for all projects where data was verifiable. There were several data quality and availability issues that limited a rigorous review of some projects.

There are 33 additional non-PBI nonresidential projects subject to evaluation for 2017. Given the increase in total projects, evaluation reporting deadlines, budgetary considerations, results garnered from the 2016 impact evaluation, along with the understanding that there are far more PBI projects subject to review (by count and rebated capacity) in 2017, we have developed a dedicated sampling approach that limits sampling error and provides statistically significant impact results for non-PBI nonresidential projects online in 2017.

Throughout the course of the 2016 impact evaluation, we satisfied several evaluation objectives, including the development of storage and customer impact metrics. While conducting that analysis, 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 2017. The results of that exercise provided the evaluation team with the minimum number of sample projects required to develop population-level SGIP storage impacts at a high level of precision (10% relative precision measured at the 90% confidence level or 90/10).

Table 3-3 presents the proposed and achieved sample design for 2017 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 2016 evaluation year includes all projects in the SGIP population subject to evaluation in 2016 and those in the 2017 evaluation year represent the incremental projects receiving upfront payments in 2017 and were not subject to evaluation in 2016. The sample design was constructed around projects in the 2016 evaluation year and the evaluation team attempted a census on all 2017 projects.

Overall, the evaluation team expected to evaluate 150 of the 278 projects in the SGIP non-PBI nonresidential population and, ultimately, evaluated 151 projects across the previously defined evaluation years. We met or exceeded all sampling targets for the 2016 evaluation year and were successful in evaluating 27 of the 33 projects in the 2017 evaluation year. The 151 projects represent 54% of all non-PBI nonresidential projects in the population and 66% of total rebated capacity. This represents an 11% increase in sampled rebated capacity compared to the 2016 evaluation (55%).

TABLE 3-3: 2017 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	2016	5	5	5	100%	99	99	100%
	2017	12	12	12	100%	360	360	100%
Hotel	2016	94	20	20	21%	1,677	396	24%
	2017	3	3	3	100%	60	60	100%
Industrial	2016	29	15	15	52%	676	347	51%
	2017	6	6	4	67%	131	88	67%
Office	2016	22	10	13	59%	490	275	56%
	2017	2	2	2	100%	45	45	100%
Other	2016	21	10	10	48%	395	178	45%
	2017	4	4	4	100%	105	105	100%
Retail	2016	32	15	19	59%	764	425	56%
School	2016	5	5	5	100%	150	150	100%
	2017	6	6	2	33%	156	45	29%
Census1	*2016*	*1*	*1*	*1*	*100%*	*1,000*	*1,000*	*100%*
Census2	*2016*	*1*	*1*	*1*	*100%*	*600*	*600*	*100%*
Special Case	*2016*	*35*	*35*	*35*	*100%*	*734*	*734*	*100%*
All Projects	2016	245	117	124	51%	6,585	4,204	64%
	2017	33	33	27	82%	856	703	82%
	Total	**278**	**150**	**151**	**54%**	**7,441**	**4,906**	**66%**

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. *Special Case* represents 35 storage systems from a developer that filed bankruptcy. The evaluation team was also able to surmise that more than 60% of these systems had either been removed from the host customers' premises or had been off-line in 2017. 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 and it's understood they contributed no impacts throughout the year. However, these projects are included in the population impact section because they are represented in the 2017 SGIP AES population.

As discussed above, non-PBI nonresidential sampling was conducted at the building type level. It was expected, however, that this approach would ultimately lead to a distribution of sample projects by PA which closely mirrored the population distribution of projects. Table 3-4 presents the sample disposition of non-PBI nonresidential projects by PA. The evaluation team sampled 41% of PG&E projects, 39% of SCE, 63% of CSE projects and both SCG projects (by count).

TABLE 3-4: 2017 SGIP NON-PBI NONRESIDENTIAL POPULATION AND SAMPLE DISPOSITION BY PA

Payment Type	PA	Project Count			Rebated Capacity (kW)		
		N	n	% in Sample	N	n	% in Sample
Non-PBI	PG&E	96	39	41%	2,011	810	40%
	SCE	71	28	39%	1,527	720	47%
	SCG	2	2	100%	40	40	100%
	CSE	72	45	63%	1,529	1,003	66%
	Others*	37	37	100%	2,334	2,334	100%
	All	**278**	**151**	**54%**	**7,441**	**4,906**	**66%**

* Others represent the 2 census projects and 35 special case projects

Figure 3-7 presents the distribution of sample nonresidential non-PBI projects by project count for each building type and PA. Figure 3-8 presents the distribution by rebated capacity.

FIGURE 3-7: DISTRIBUTION OF 2017 SGIP AES NON-PBI NONRESIDENTIAL SAMPLE PROJECT COUNT BY BUILDING TYPE AND PA

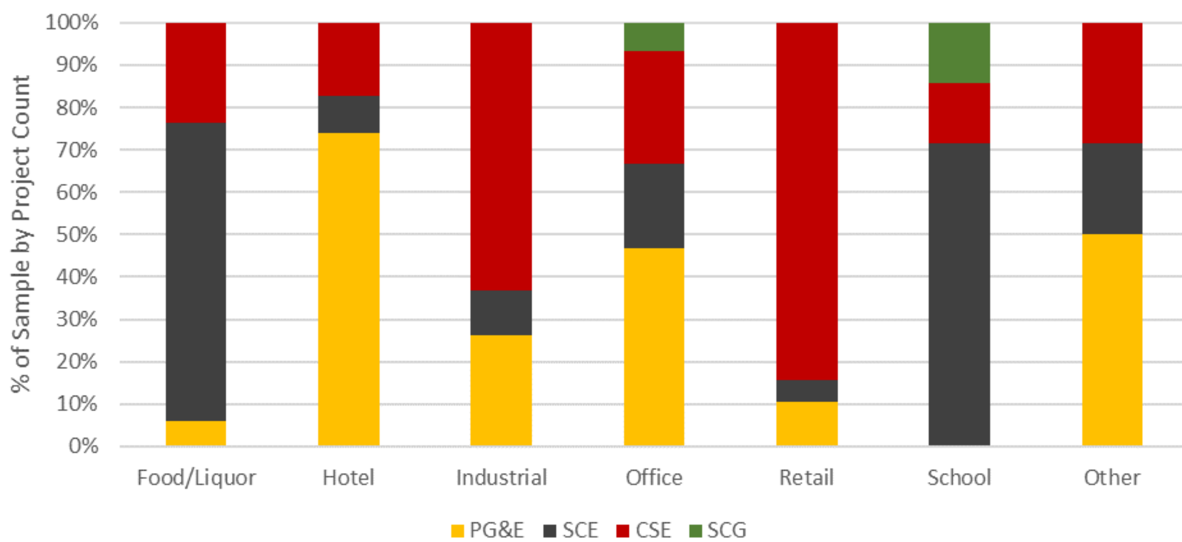
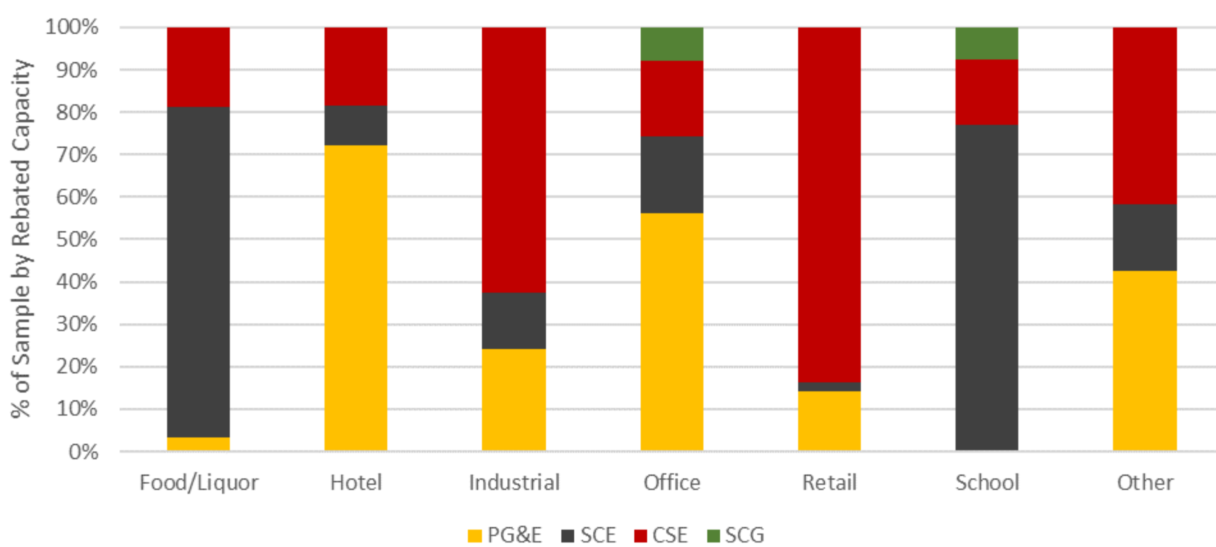


FIGURE 3-8: DISTRIBUTION OF 2017 SGIP AES NON-PBI NONRESIDENTIAL REBATED CAPACITY BY BUILDING TYPE AND PA



3.2.3 Residential Sample Disposition

Residential projects represent roughly 2 MW of the SGIP AES program capacity of 67 MW. The 2 MW represent a 9% increase in rebated capacity for residential projects within SGIP from 2016. There are 407 residential projects subject to measurement and verification which represents a 5% increase by project count from 2016. The storage systems range in rebated capacity with roughly 94% representing 4.5 to 5 kW systems.

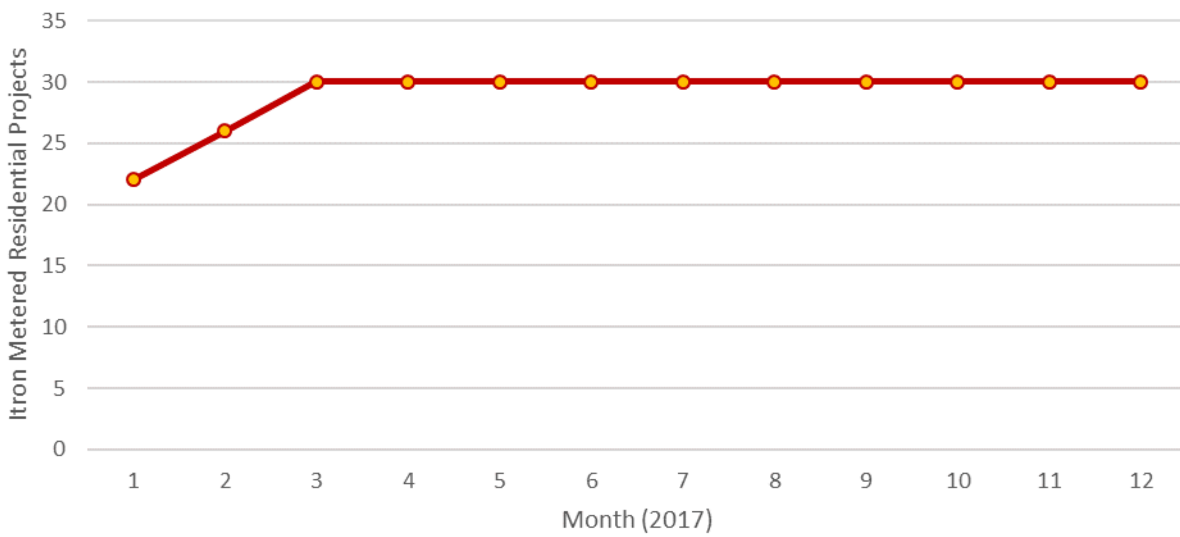
As discussed in Appendix B, this evaluation relies heavily on storage project developer and manufacturer data. Unfortunately, limitations in storage industry data acquisition systems reduced our assessment of residential program impacts in 2016 to qualitative rather than quantitative metrics.[3] To address these shortcomings, the evaluation team has leveraged an additional data source to develop impacts for SGIP residential projects.

Itron and its subcontractors 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. Data from these meters have allowed the evaluation team to better quantify the impacts from storage and provide an additional data stream to compare with the developer storage data.

Figure 3-9 presents the number of residential storage projects with installed metering equipment along with the timeline of data availability throughout 2017. Overall, twenty-two projects have metered data for the entirety of 2017, four additional projects were included in February and the remaining four were installed in March.

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

FIGURE 3-9: AVAILABLE RESIDENTIAL STORAGE METERING DATA FOR 2017



The evaluation team successfully verified the storage dispatch for 28 of the 30 residential metered projects.[4] These projects ultimately represented the sample of residential projects for this evaluation. As detailed above, historic data quality issues precluded a rigorous analysis of residential projects in the past few evaluation periods, so the evaluation team was unable to develop expected sample level precision estimates. However, the expectation was that these systems were all being utilized in a similar manner – primarily for back-up and to meet minimum SGIP cycling requirements – so a sample size of 28 would be sufficient to develop population level impacts with a high level of precision.

Table 3-5 presents the sample disposition for residential projects by PA. Of the 28 projects in the sample, 15 were installed in homes administered by PG&E, followed by 8 in SCE and 5 in CSE territory. Overall, the residential sample represents roughly 7% of all residential projects by project count and rebated capacity. As presented in Section 2, changes in how SGIP is being administered beginning in PY 2017 – a first-come, first-served reservation system to a lottery which prioritizes storage systems paired with renewables – will likely change the make-up of the residential population, so future evaluations will be required to take into account this evolution (See below in Section 3.3).

[4] Two metered projects were removed from the analysis sample based on data quality issues. One metered system provided 2 months of data early in the year and nothing thereafter. The other exhibited anomalous patterns of charge and discharge and was deemed unverifiable.

TABLE 3-5: 2017 SGIP RESIDENTIAL POPULATION AND SAMPLE DISPOSITION BY PA

Customer Type	PA	Project Count			Rebated Capacity (kW)		
		N	n	% in Sample	N	n	% in Sample
Residential	PG&E	173	15	9%	892	75	8%
	SCE	139	8	6%	714	40	6%
	SCG	1	0	0%	14	-	0%
	CSE	94	5	5%	496	25	5%
	All	**407**	**28**	**7%**	**2,116**	**140**	**7%**

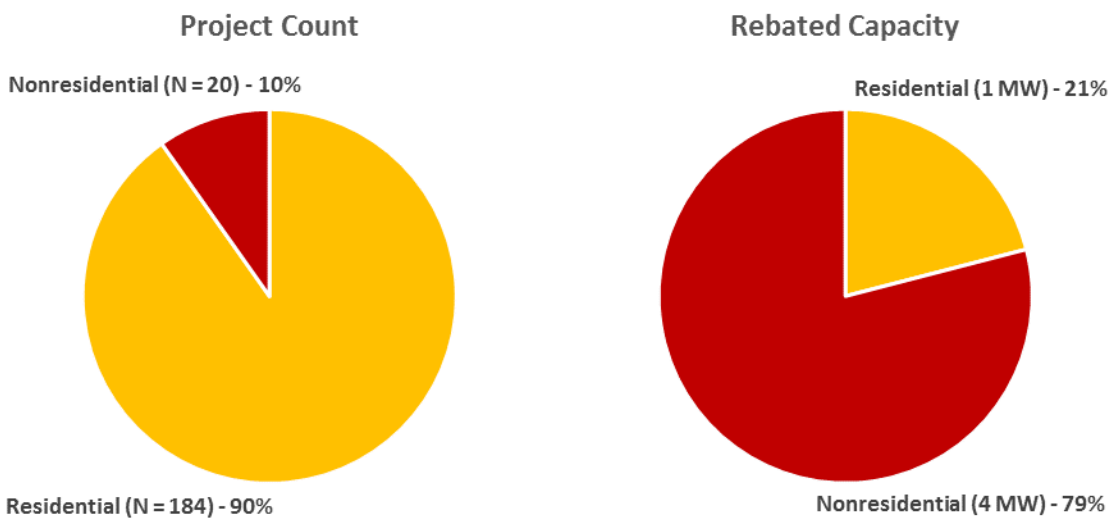
3.3 SGIP POPULATION BEYOND 2017

The above sections detail the characterization of the SGIP AES population subject to evaluation in 2017 and provides a summary of how changes to the disposition of that population from 2016 to 2017 dictated the evaluation approach. Nonresidential PBI projects constitute the most significant percentage of systems receiving upfront payments in 2017 from PY 2016 and prior (both in terms of project count and rebated capacity). While the remainder of this report presents the results associated with projects subject to evaluation in 2017, here we provide a snapshot of how the disposition of the population is changing from 2017 to 2018. 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.

We define the SGIP energy storage queue as applications submitted to SGIP that are currently in draft, waitlist, suspended or review stages. As of July 2018, there are 258 MW of SGIP rebated capacity in the energy storage queue, representing almost four times the current capacity of the program. Of these 258 MW, almost 800 kW of rebated capacity are for thermal storage – a technology that has not yet been subject to SGIP evaluation (no projects have been paid incentives). The remaining 257 MW are electrochemical storage.

In addition to the projects in the SGIP queue, the PAs have paid upfront incentives to 204 projects during 2018 representing over 5 MW of rebated capacity. This represents a 25% increase in project count compared to 2017 and a 7% increase in rebated capacity. Figure 3-10 presents the projects receiving upfront payments through the second quarter of 2018 by host customer sector. Most projects (90%) are residential projects (184) which signals a significant shift from what was observed during this evaluation period.

FIGURE 3-10: SGIP STORAGE PROJECT COUNT AND REBATED CAPACITY BY HOST CUSTOMER SECTOR (2018)



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 2017. 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
- **Observed Distribution System Objectives – Section 4.7**
  - Analyze and quantify the impacts of storage on the electric distribution system and substation transformer loading

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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 including 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 4.8**
  - 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 and utility marginal costs
- **Observed Behavior of Storage Systems Co-located with PV – Section 4.9**
  - Analyze the storage charge/discharge timing and behavior of residential storage systems paired with PV
- **Population Level Impact Objectives – Section 4.10**
  - Combine project-specific sample data from the objectives above to *quantify the magnitude* of total population level impacts for SGIP AES systems operating throughout 2017

4.2 PERFORMANCE METRICS

Below we present the performance metrics developed from the sample of projects evaluated as part of the 2017 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 achieve an AES capacity factor of at least 10% 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% capacity factor.

Another key performance metric is roundtrip efficiency (RTE), which is an eligibility requirement for the SGIP.[5] 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% to 100%. 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% 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 135 nonresidential projects have capacity factors of less than 5% (of 248 total sampled projects) with non-PBI projects representing much of that total (90). We observed 69 nonresidential projects with a capacity factor between 5 and 10% with 18 of those representing non-PBI projects and 51 representing PBI projects. Thirty-nine projects exhibited capacity factors of a least 10%. All but five of these projects were PBI. Furthermore, two non-PBI projects and four PBI projects exhibited a capacity factor greater than 20%. The mean capacity factor was 4.3% for non-PBI projects and 7.2% 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% capacity for 1,040 hours – the amount of energy in the two is the same, each constituting 520 discharge hours.

5 AES systems must maintain a round trip efficiency equal to or greater than 69.6% in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5%, assuming a 1% annual degradation rate. (2016 SGIP Handbook, https://www.selfgenca.com/documents/handbook/2016)

FIGURE 4-1: HISTOGRAM OF NONRESIDENTIAL AES DISCHARGE CAPACITY FACTOR (2017)

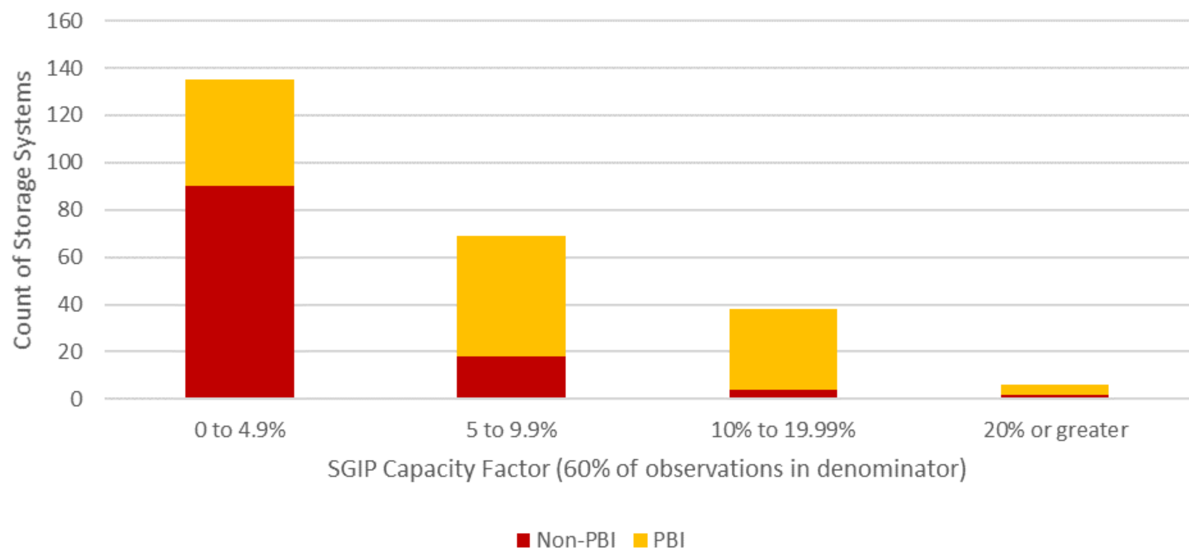


Figure 4-2 presents the distribution of RTEs for PBI and non-PBI and Figure 4-3 presents the RTEs for each of the 248 projects by descending RTE. The mean observed RTE was 51% for non-PBI projects and 81% for PBI projects over the entire evaluation period.

FIGURE 4-2: HISTOGRAM OF NONRESIDENTIAL ROUNDTRIP EFFICIENCY (2017)

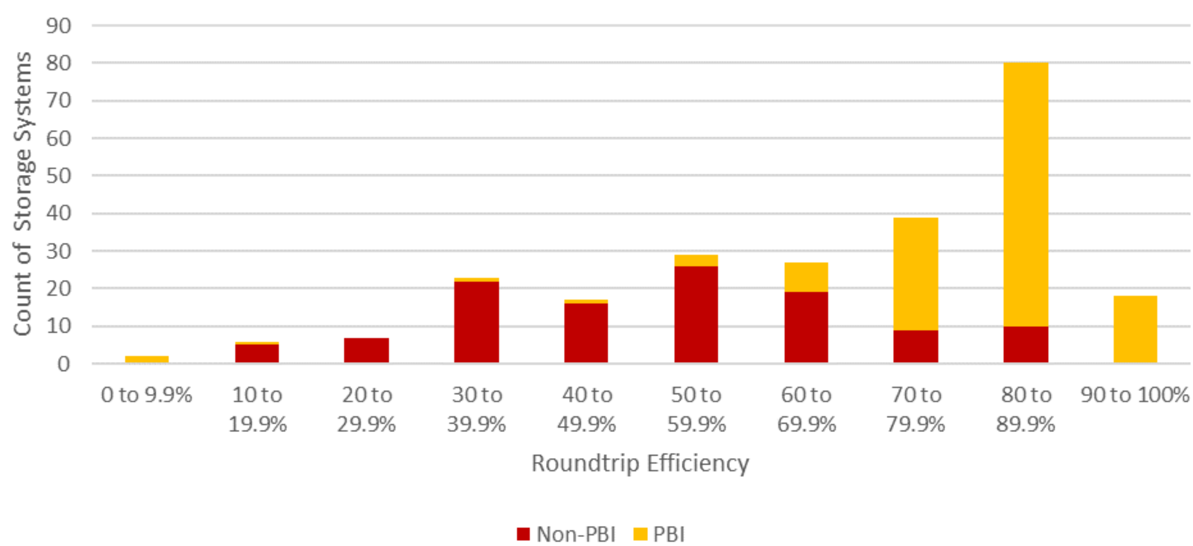
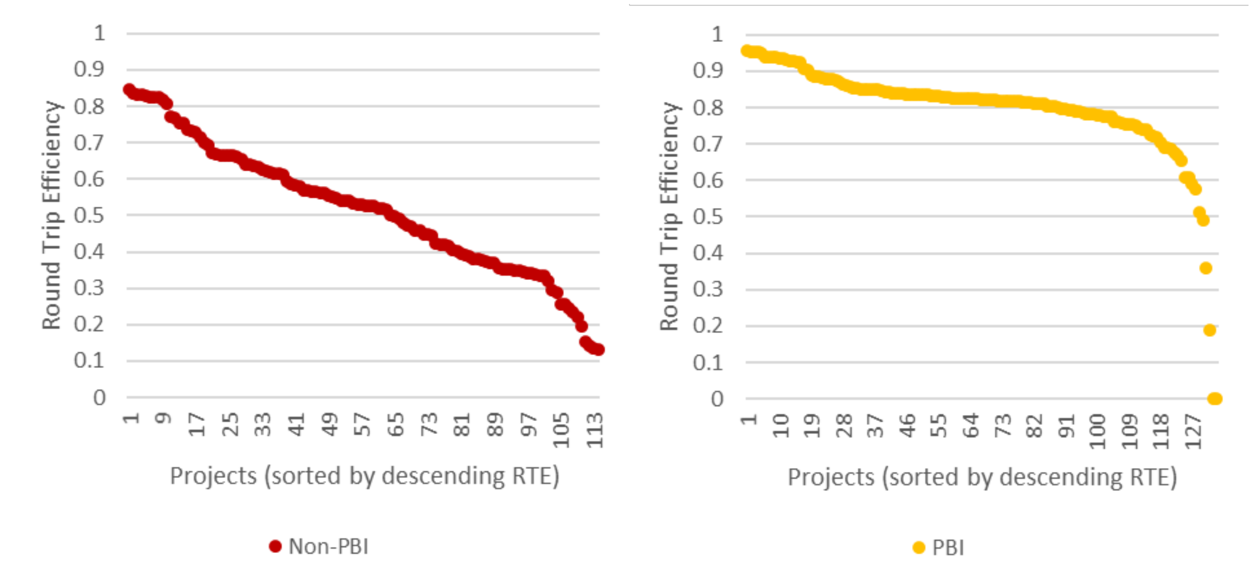


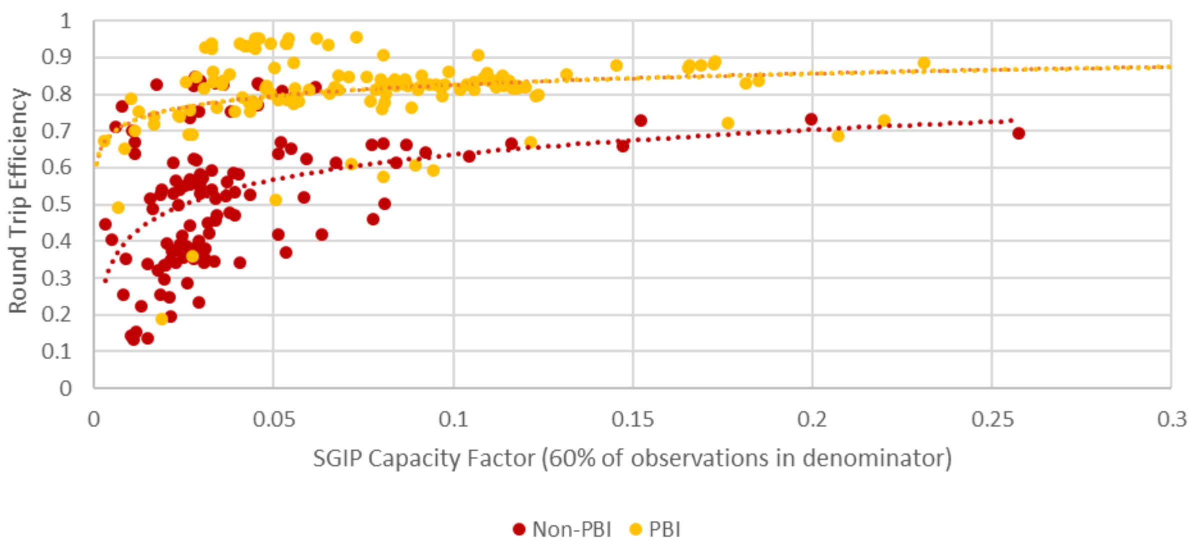
FIGURE 4-3: ROUNDTRIP EFFICIENCY FOR NONRESIDENTIAL PROJECTS (2017) – SORTED BY DESCENDING RTE



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 4-4. Systems with the lowest capacity factors tend to have the lowest RTEs.[6]

[6] The SGIP capacity factor in the figure below has been capped at 0.3. One PBI project exhibited a CF of 0.42 and received an upfront payment in June of 2017. The evaluation team verified storage dispatch for four months thereafter. The CF was calculated only for the time period of verifiable data.

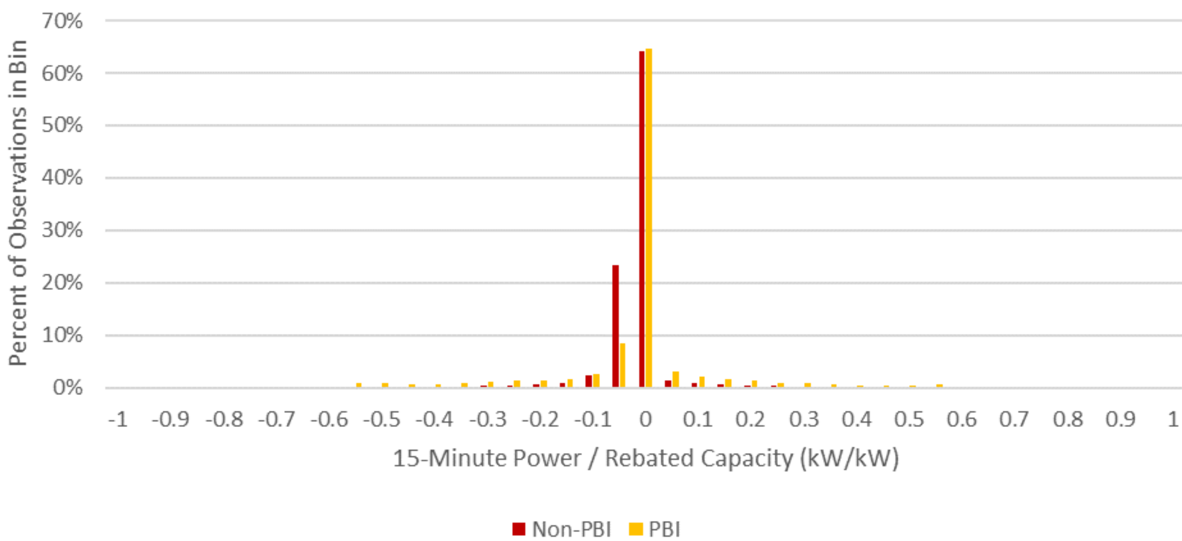
FIGURE 4-4: TOTAL ROUNDTRIP EFFICIENCY VERSUS CAPACITY FACTORS (ALL NONRESIDENTIAL PROJECTS)



We also examined the dispatch performance of the storage systems relative to the rebated capacity of the systems. Figure 4-5 presents the 15-minute kW storage charge (-) and discharge (+) normalized by storage system rebated capacity for non-PBI and PBI systems.[7] For both categories, most observations (approximately 60%) are at or near zero. This suggests that over the course of 2017, most systems were idle or dispatching at a small percentage of capacity. Both distributions skew towards charge, indicating more charging than discharging (as they should to have RTEs less than one). For non-PBI systems, a significant percentage (23%) of observations are slightly negative. This distribution suggests that a significant portion of non-PBI observations are spent serving parasitic loads. The charge/discharge 15-minute power for PBI projects is more normally distributed.

[7] It's important to note that the x-axis was set to -1 to 1 so that the scale of observations further from zero could be visualized. There are 15-minute charge/discharge observations for PBI and non-PBI projects that are -/+ 2 times rebated capacity.

FIGURE 4-5: HISTOGRAM OF NON-PBI AND PBI NORMALIZED 15-MINUTE POWER



Residential Project CFs and RTEs

The capacity factors for residential projects are presented below in Figure 4-6. A total of 20 projects had capacity factors of less than 2% (of 28 total sampled projects), four projects exhibited a capacity factor between 2 and 5%, three projects were between 5 and 10% and one project exhibited a CF greater than 10%. Note the capacity factor is calculated over the course of time with available data, so a project CF with metered data available from March through December of 2017 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 2.2% for residential projects during the evaluation period.

FIGURE 4-6: HISTOGRAM OF RESIDENTIAL AES DISCHARGE CAPACITY FACTOR (2017)

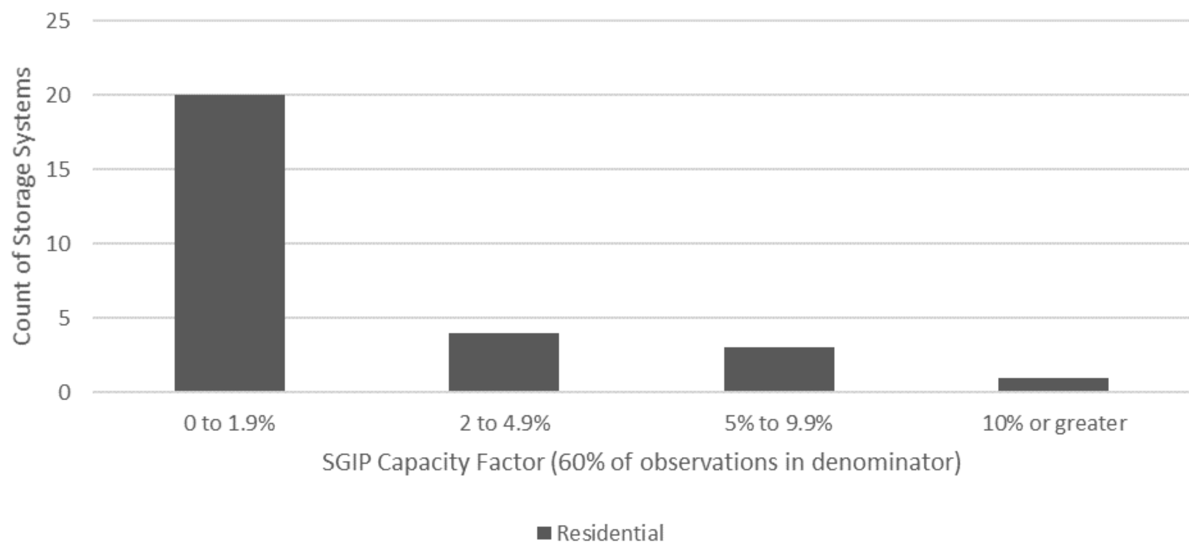


Figure 4-7 presents the distribution of RTEs for the 28 residential projects and Figure 4-8 presents the RTEs for each project by descending RTE. Thirteen residential projects exhibited RTEs in the 20% to less than 40% range, three residential projects had an RTE less than 10% and four residential project RTEs were within 70% to 80%. The mean observed residential RTE was 38%.

FIGURE 4-7: HISTOGRAM OF RESIDENTIAL ROUNDTRIP EFFICIENCY (2017)

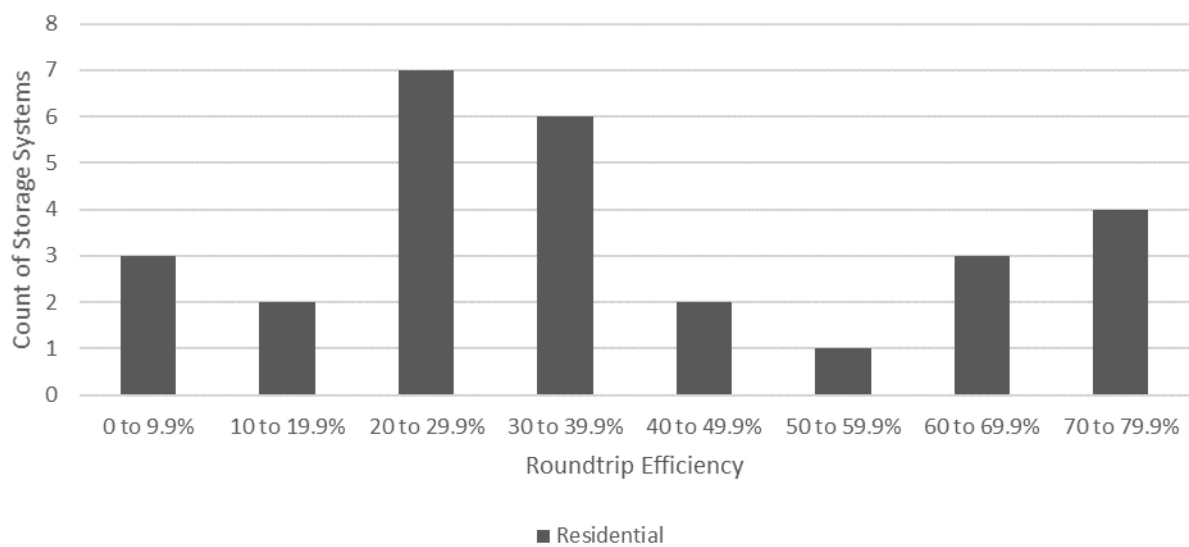
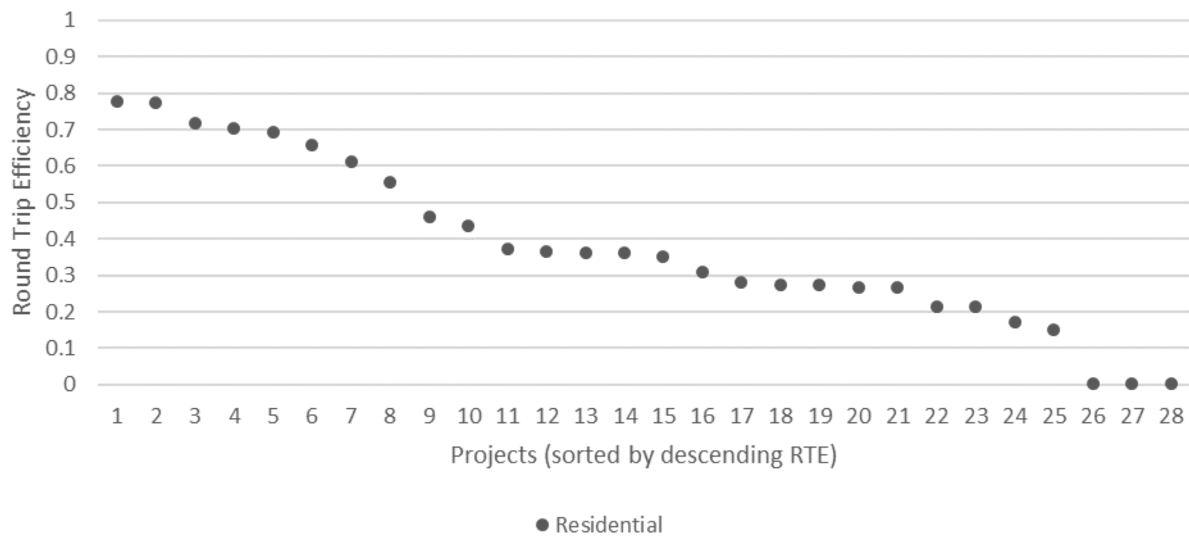


FIGURE 4-8: ROUNDTRIP EFFICIENCY FOR RESIDENTIAL PROJECTS (2017) – SORTED BY DESCENDING RTE



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. The evaluation team observed significant differences in the way storage systems are being utilized for residential customers compared to nonresidential customers. Residential customers in 2017 were primarily on tariffs with a tiered pricing structure, whereas nonresidential customers were on tariffs with TOU energy rates and demand charges. SGIP requirements (52 cycles per year for residential projects compared to 130 for nonresidential, CF requirements for PBI projects and RTE program eligibility requirements for nonresidential systems) also dictate differences in the storage dispatch behavior from residential to nonresidential customers. This is evident in Figure 4-9. The average monthly RTEs are significantly greater in the latter months of the year, namely October, November and December. The evaluation team observed more consistent, daily storage cycling from residential projects in those months. Nonresidential customers, however, are utilizing their storage systems to realize bill savings (namely non-coincident peak demand reduction), so monthly RTEs don't vary as significantly across months as those from residential systems.

FIGURE 4-9: AVERAGE MONTHLY ROUNDTRIP EFFICIENCY FOR RESIDENTIAL PROJECTS (2017)

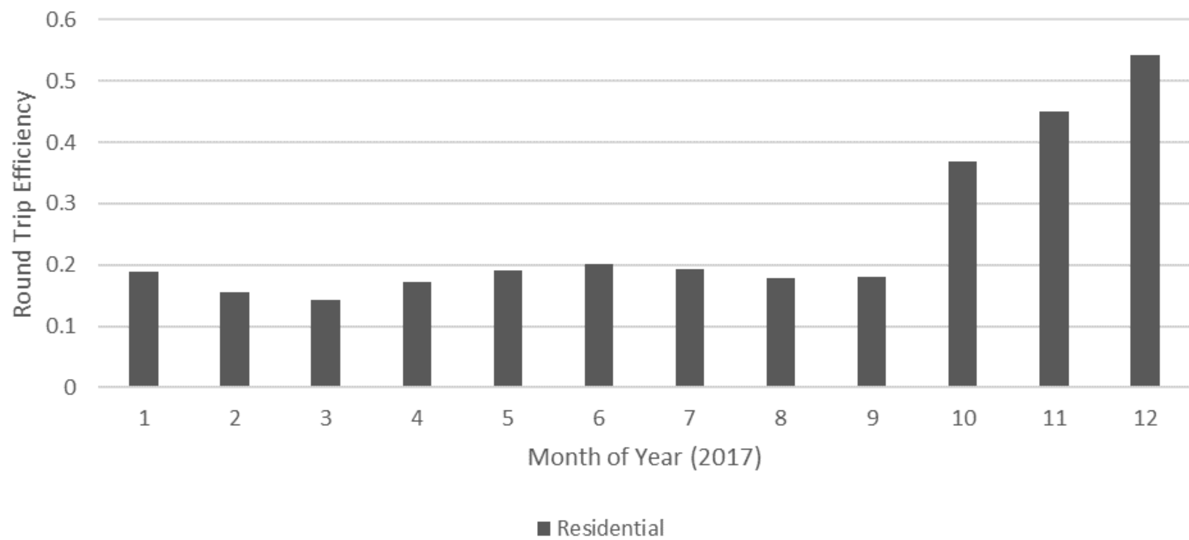


Figure 4-10 below presents the number of cycling events for each project throughout 2017. The SGIP requires residential storage systems to cycle 52 times throughout the year.[8] Twenty-one of the twenty - eight projects met the 52-cycle requirement. One project was online throughout the entirety of 2017, discharging each day throughout the afternoon hours and charging thereafter. Of the seven that did not meet the requirement, three were idle throughout the entire metering period.

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

FIGURE 4-10: ANNUAL SINGLE CYCLE EVENTS FOR SAMPLE OF RESIDENTIAL PROJECTS

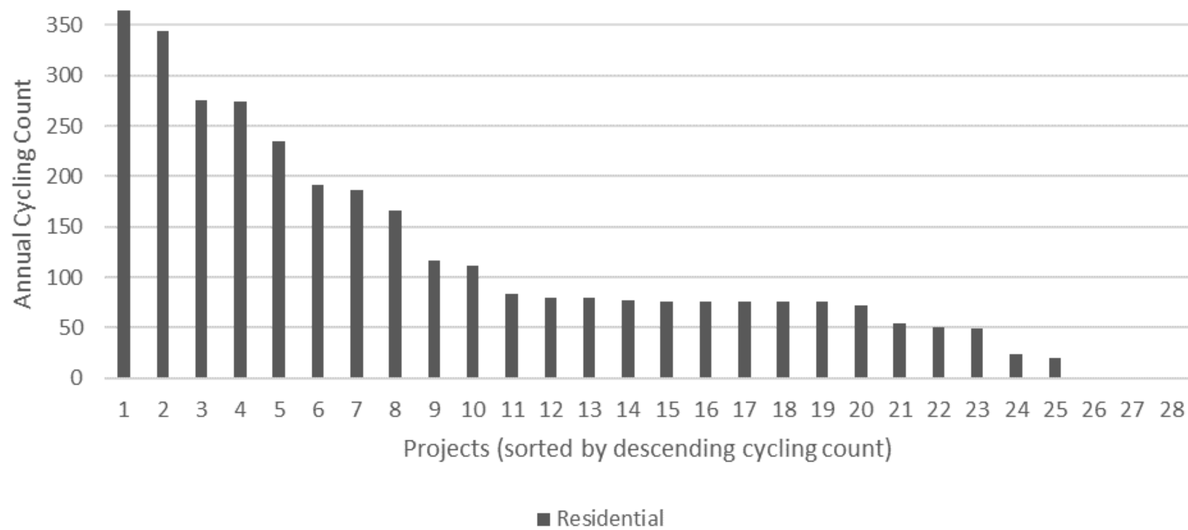
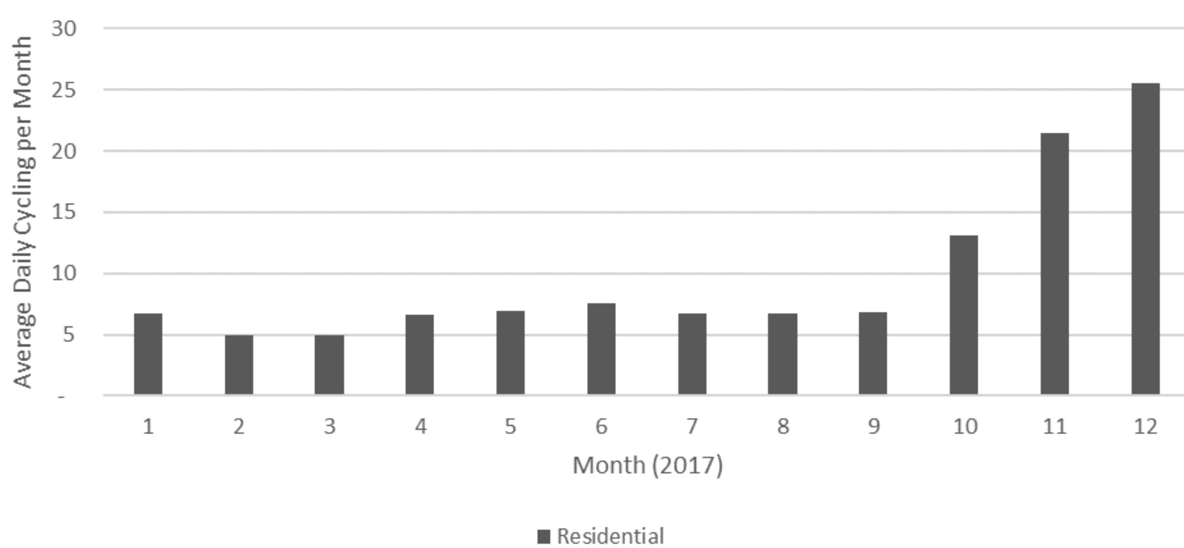


Figure 4-11 presents the average number of cycles across the metered sample of 28 projects by month. This figure mirrors the RTEs presented in Figure 4-9 as more utilized systems tend to have higher RTEs and parasitic losses from idle systems generally lead to lower RTEs. In 2017, there were 5 to 8 projects cycling throughout the early winter and summer months. Most projects begin cycling in October throughout the remainder of the year. Presumably they are programmed to meet the 52-cycle per year requirement.

FIGURE 4-11: AVERAGE MONTHLY SINGLE CYCLE EVENTS FOR SAMPLED RESIDENTIAL PROJECTS



4.2.2 Cross-Year Performance Impact Comparisons (2016 to 2017)

The evaluation team also compared the performance metrics developed from the 2016 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 2017 are not compared to projects in the 2016 population. Instead, the analysis is limited to projects that were operational during both 2016 and 2017. It is important to note, many projects evaluated in 2016 received their upfront payment at different times throughout the year, so the performance metrics did not incorporate a full calendar year of impacts. All projects completed during 2016 were online and operating throughout the entirety of 2017, so any potential changes in performance from one year to the next may only reflect that difference.

Figure 4-12 and Figure 4-13 present those comparisons for RTEs and CFs, respectively. Any point on the figure above the black line represents a project with a greater RTE in 2017 relative to 2016. On average, non-PBI projects exhibit greater RTEs in 2017 compared to their own operation in 2016. For PBI projects, the differences are negligible. Similarly, non-PBI projects generally are being utilized more in 2017 compared to the previous year. PBI projects, however, appear to be utilized less – exhibiting lower CFs in 2017, on average, than 2016.

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 in November of 2016 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 2017, where data was available and verifiable. Differences in performance across the 2 years could signal a change in operation or could represent differences in the time frame in which impacts were calculated for each year.

FIGURE 4-12: CROSS-YEAR ROUNDTRIP EFFICIENCY COMPARISON (2016 TO 2017)

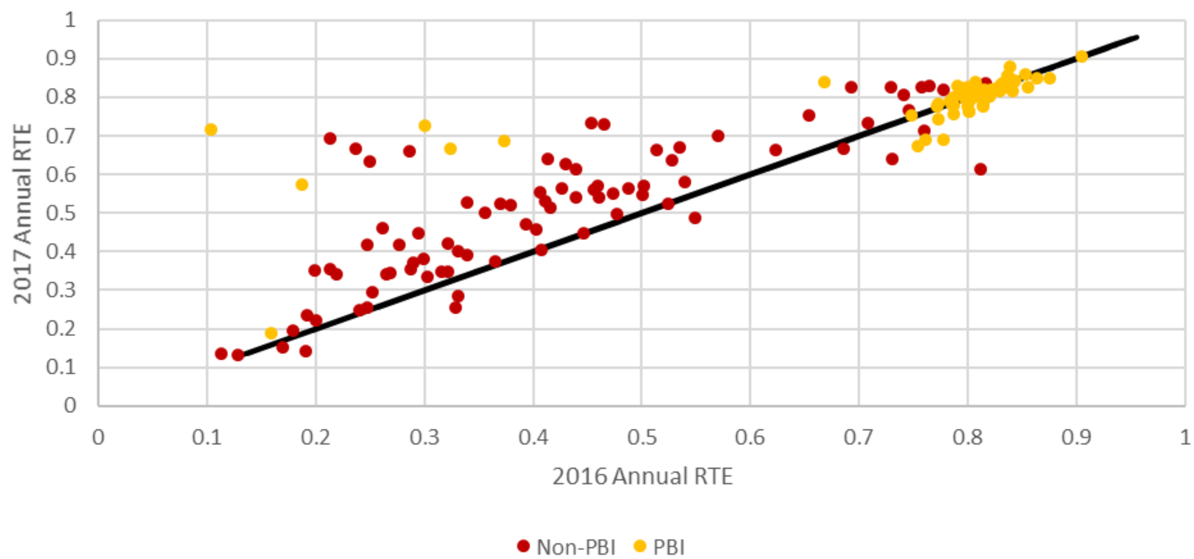
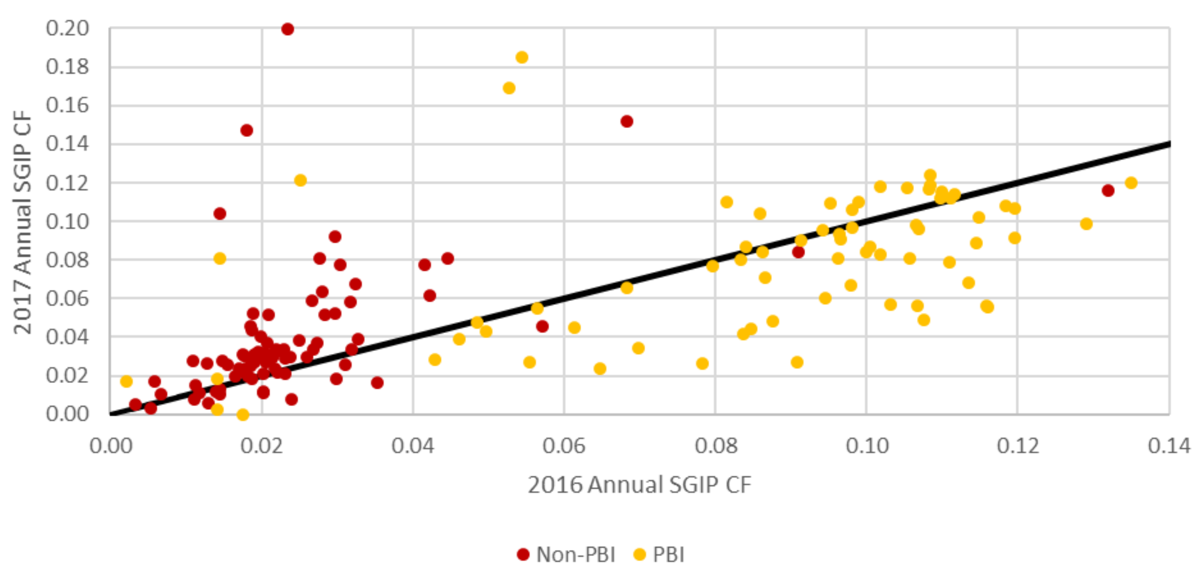


FIGURE 4-13: CROSS-YEAR SGIP CAPACITY FACTOR COMPARISON (2016 TO 2017)



4.2.3 Influence of Parasitic Loads on Performance

The mean observed RTE for non-PBI projects (51%) was far lower than for PBI projects (81%). Likewise, Figure 4-1 and Figure 4-4 provided evidence that these systems were under-utilized with capacity factors generally ranging from 0.01 to 0.05. One consequence of this underutilization is the accumulation of standby losses and parasitic loads associated with system cooling, communications and other power electronic loads. We attempted to quantify the influence of these losses by classifying the storage dispatch into three general categories:

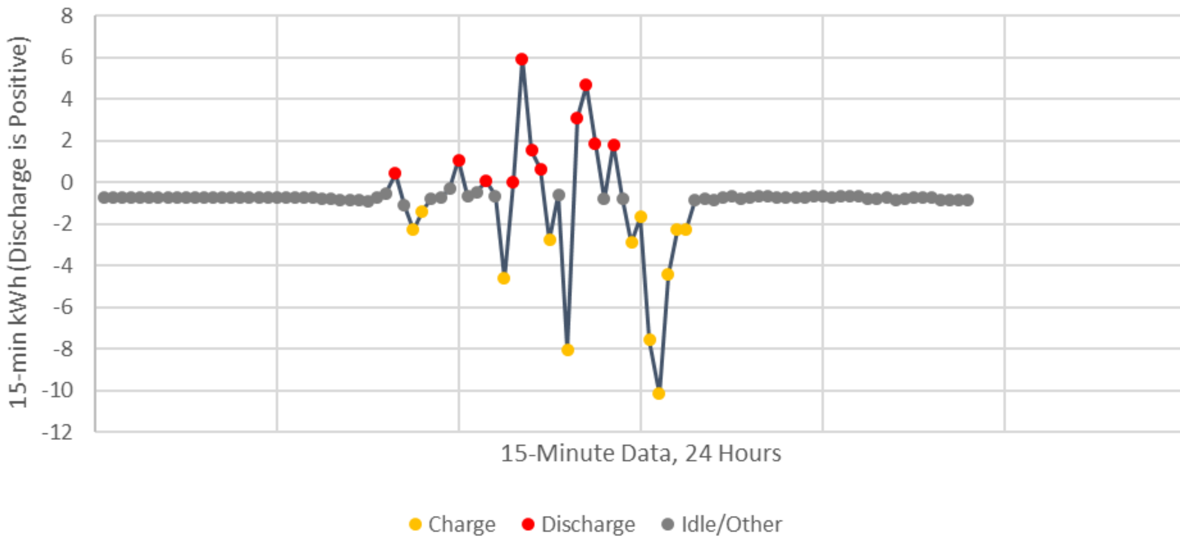
- Discharge – any 15-minute discharge (+) event
- Charge – any 15-minute charge (-) event not identified as an idle/other period
- Idle/Other – any 15-minute charge (-) event not identified as a charge period
  - Identify 15-minute charge (-) event when storage system is NOT discharging
  - Develop a 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[9]
  - Develop a weighted[10] average of all 15-minute charge observations below the cut point
  - These observations represented the parasitic load

Figure 4-14 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.

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

[10] 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 4-14: EXAMPLE CLASSIFICATION OF 15-MINUTE POWER KW CHARGE/DISCHARGE/IDLE



Nonresidential Parasitic Influence

Figure 4-15 and Figure 4-16 present 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, respectively. Non-PBI projects are further split out by the building type (or facility type).

The average parasitic for non-PBI ranges from zero to roughly 0.35 kWh at the 15-minute level.[11] 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% to 6% for non-PBI projects.[12]

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

[12] 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 4-15: MEAN PARASTIC KWH AND MEAN PARASITIC AS A PERCENT OF REBATED CAPACITY (BY BUILDING TYPE FOR NON-PBI NONRESIDENTIAL)

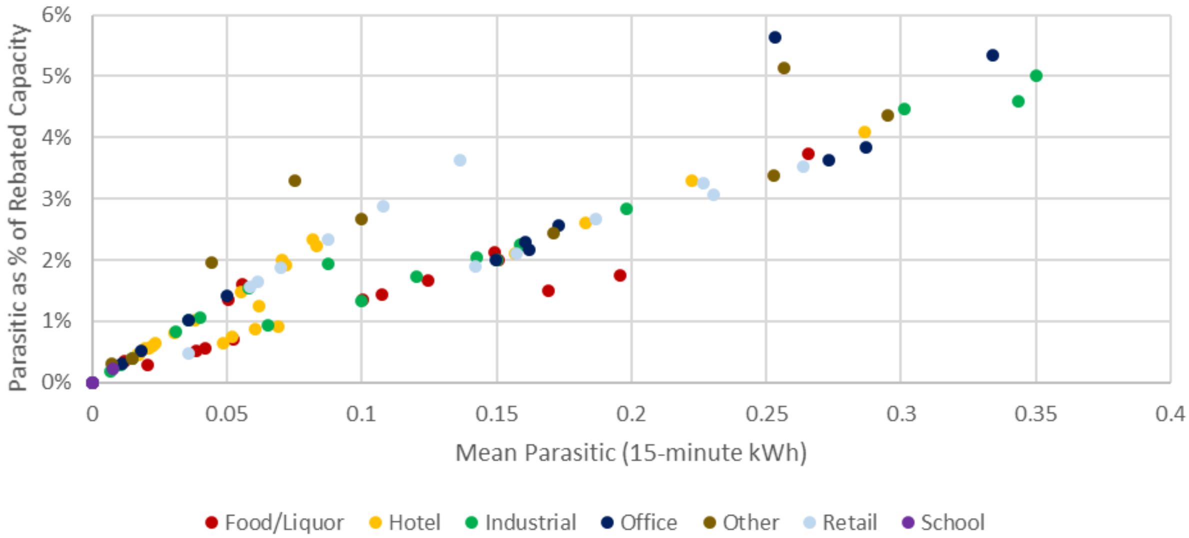
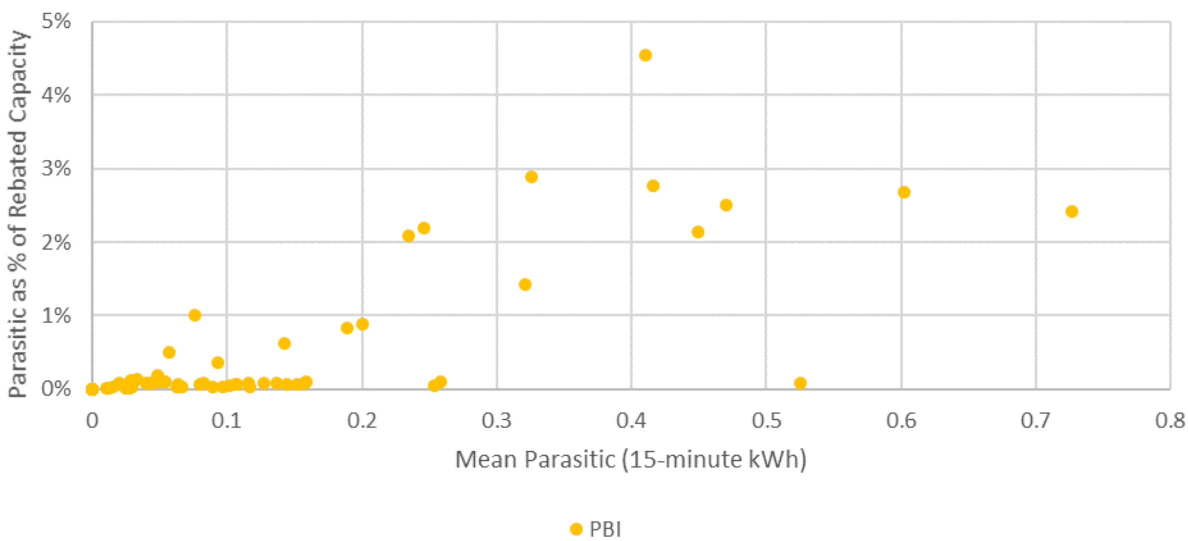
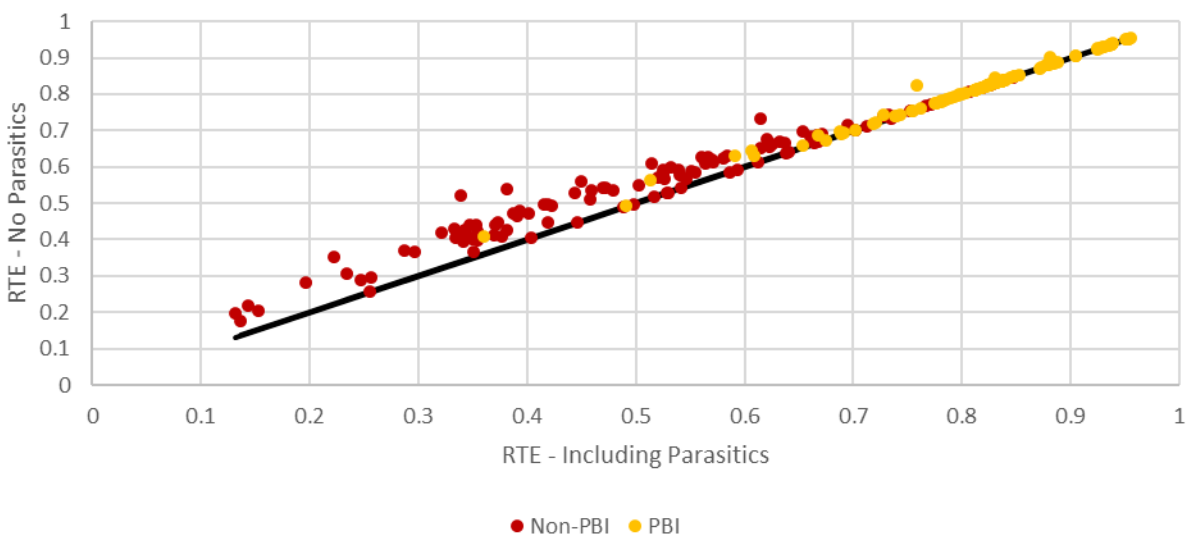


FIGURE 4-16: MEAN PARASTIC KWH AND MEAN PARASITIC AS A PERCENT OF REBATED CAPACITY (PBI PROJECTS)



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 4-17. 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 30% to 40% range would exhibit RTEs in the 40% to 50% range if the parasitic loads were removed.

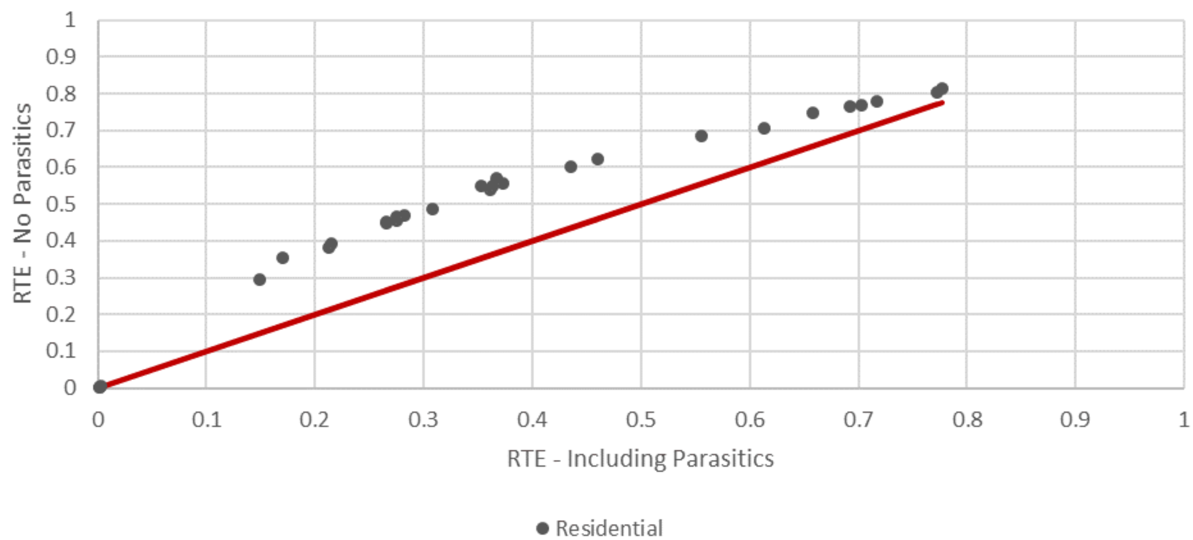
FIGURE 4-17: INFLUENCE OF PARASITICS ON ROUNDTRIP EFFICIENCY (NONRESIDENTIAL PROJECTS)



Residential Parasitic Influence

The average parasitic observed in the residential metered data was 0.09 kWh at the 15-minute interval or roughly 40 watts. As presented above in Figure 4-6, residential systems were under-utilized, especially throughout the first three quarters of 2017, so the small parasitic draw, at the 15-minute level, adds up considerably throughout the year. Projects with calculated RTEs in the 30 to 40% range would exhibit RTEs of 50 to 60% in the absence of that idle load.

FIGURE 4-18: INFLUENCE OF PARASITICS ON ROUNDTRIP EFFICIENCY (RESIDENTIAL PROJECTS)



4.3 CUSTOMER IMPACTS

Below we present the customer impacts developed from the sample of projects evaluated as part of the 2017 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 bill 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). Figure 4-19 provides the TOU periods in local time for each of the three IOUs where SGIP storage projects were located. These periods are all defined by workday (Monday through Friday). Weekends and holidays are considered off-peak.

FIGURE 4-19: TIME-OF-USE PERIODS BY IOU (LOCAL TIME)

	Summer Weekday			Winter Weekday		
Hour	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
0	Off	Off	Off	Off	Off	Off
1	Off	Off	Off	Off	Off	Off
2	Off	Off	Off	Off	Off	Off
3	Off	Off	Off	Off	Off	Off
4	Off	Off	Off	Off	Off	Off
5	Off	Off	Off	Off	Off	Off
6	Off	Off	Part	Off	Off	Part
7	Off	Off	Part	Off	Off	Part
8	Off/Part	Part	Part	Off/Part	Part	Part
9	Part	Part	Part	Part	Part	Part
10	Part	Part	Part	Part	Part	Part
11	Part	Part	Peak	Part	Part	Part
12	Peak	Peak	Peak	Part	Part	Part
13	Peak	Peak	Peak	Part	Part	Part
14	Peak	Peak	Peak	Part	Part	Part
15	Peak	Peak	Peak	Part	Part	Part
16	Peak	Peak	Peak	Part	Part	Part
17	Peak	Peak	Peak	Part	Part	Peak
18	Part	Part	Part	Part	Part	Peak
19	Part	Part	Part	Part	Part	Peak
20	Part	Part	Part	Part	Part	Part
21	Off/Part	Part	Part	Off/Part	Off	Part
22	Off	Part	Off	Off	Off	Off
23	Off	Off	Off	Off	Off	Off

The summer peak period extends from 12 pm through 6 pm for PG&E and SCE and from 11 am through 6 pm for SDG&E (PDT). Each IOU also has a partial-peak period extending from the shoulder hours on either side of the peak period and an off-peak period that extends from the late evening into the early morning. PG&E and SCE do not have a peak period during the winter. The SDG&E winter peak extends from 5 pm through 8 pm.

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 4-20 and Figure 4-21 present the discharge behavior for 244 nonresidential projects during the summer TOU period for non-PBI and PBI projects, respectively. Each vertical bar on the figures represents an individual project sorted by descending percentage of energy discharged during TOU peak periods. The majority of non-PBI projects are discharging during peak and partial-peak times, but as evidenced in gray, projects are also discharging throughout off-peak hours. This relationship is more prevalent for PBI projects.

FIGURE 4-20: 2017 SGIP NONRESIDENTIAL NON-PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD

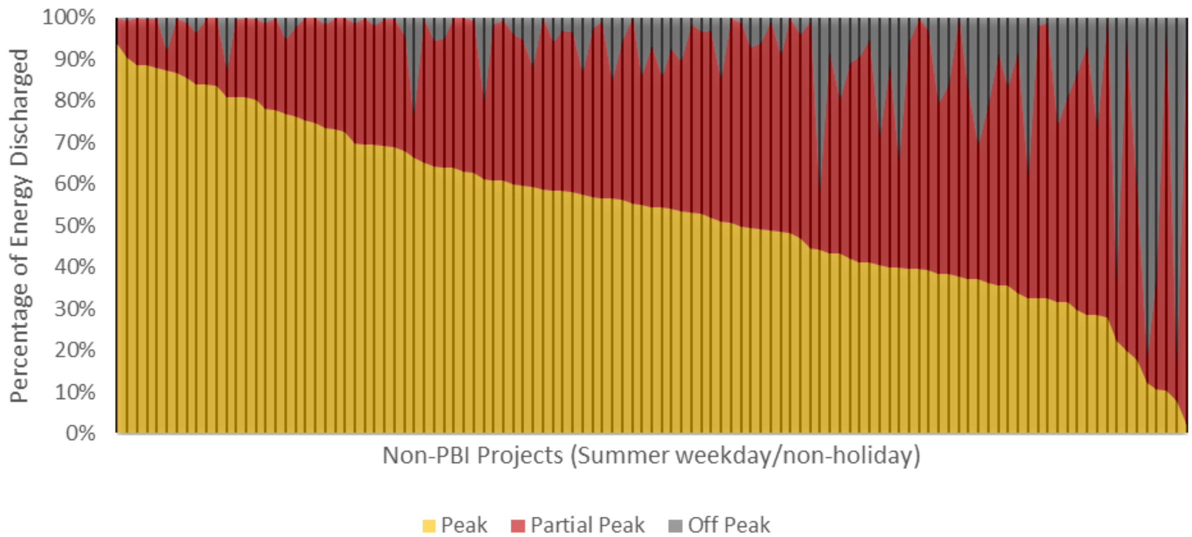


FIGURE 4-21: 2017 SGIP NONRESIDENTIAL PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD

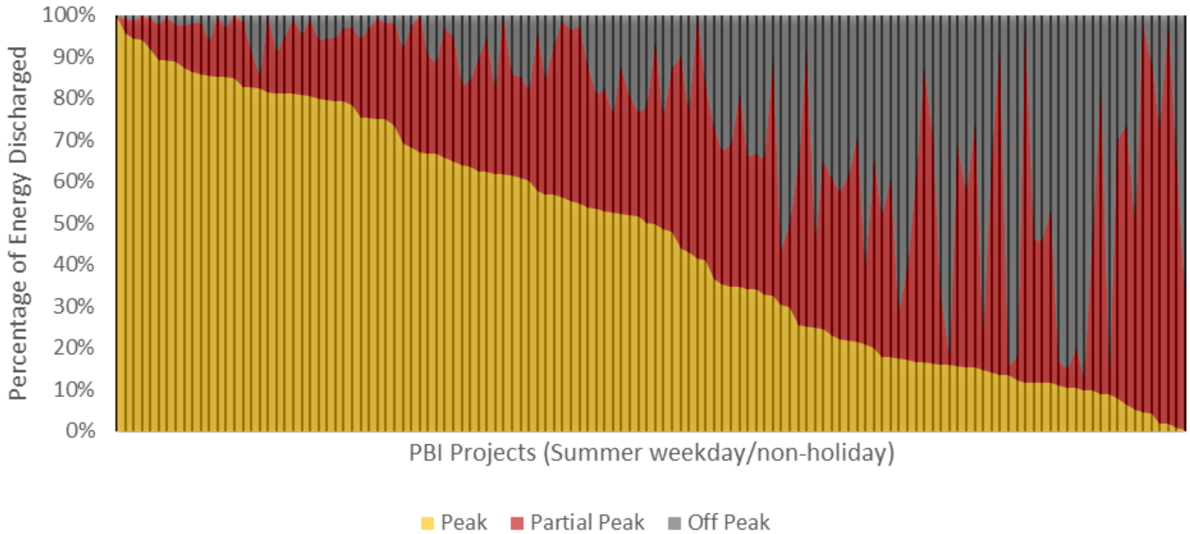


Figure 4-22 and Figure 4-23 present storage discharge by winter TOU period. Only one IOU has a commercial peak period rate during the winter.

FIGURE 4-22: 2017 SGIP NONRESIDENTIAL NON-PBI PROJECT DISCHARGE BY WINTER TOU PERIOD

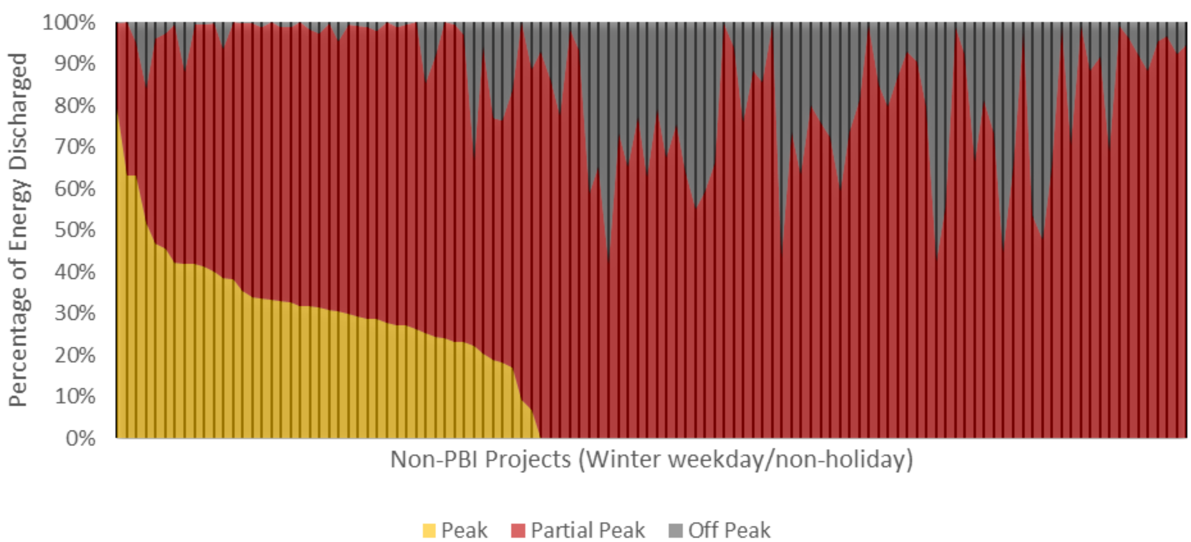
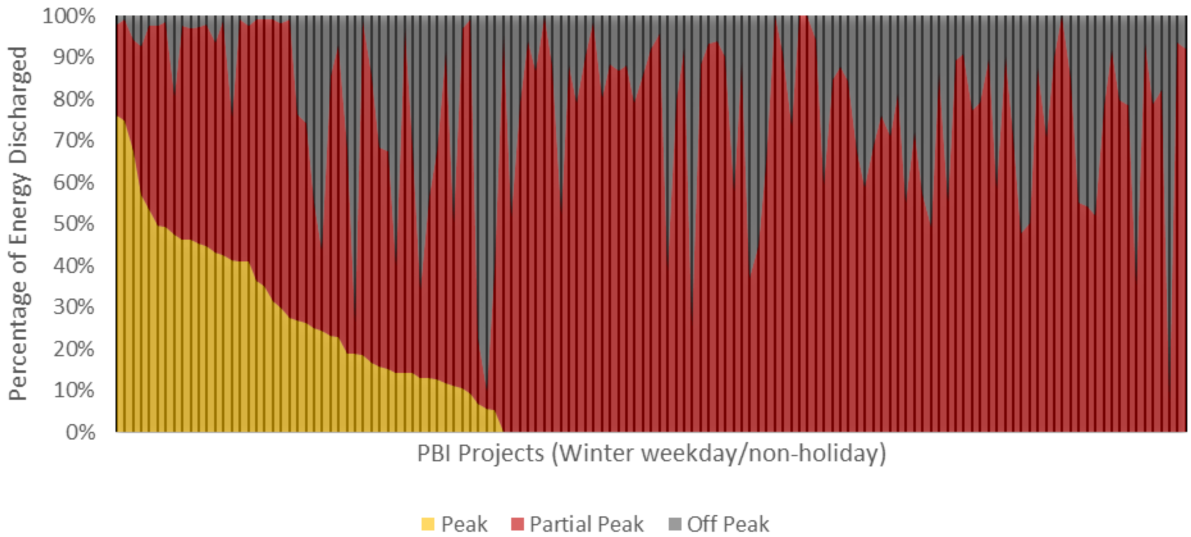


FIGURE 4-23: 2017 SGIP NONRESIDENTIAL PBI PROJECT DISCHARGE BY WINTER TOU PERIOD



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. Sixty-three non-PBI projects discharged 50% or more of their storage energy during the summer peak period. Sixty-four PBI projects discharged 50% or more of their storage energy during the summer peak period.[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, part-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 (0.059 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.

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

FIGURE 4-24: HOURLY NET DISCHARGE KW PER REBATED KW BY SUMMER TOU PERIOD

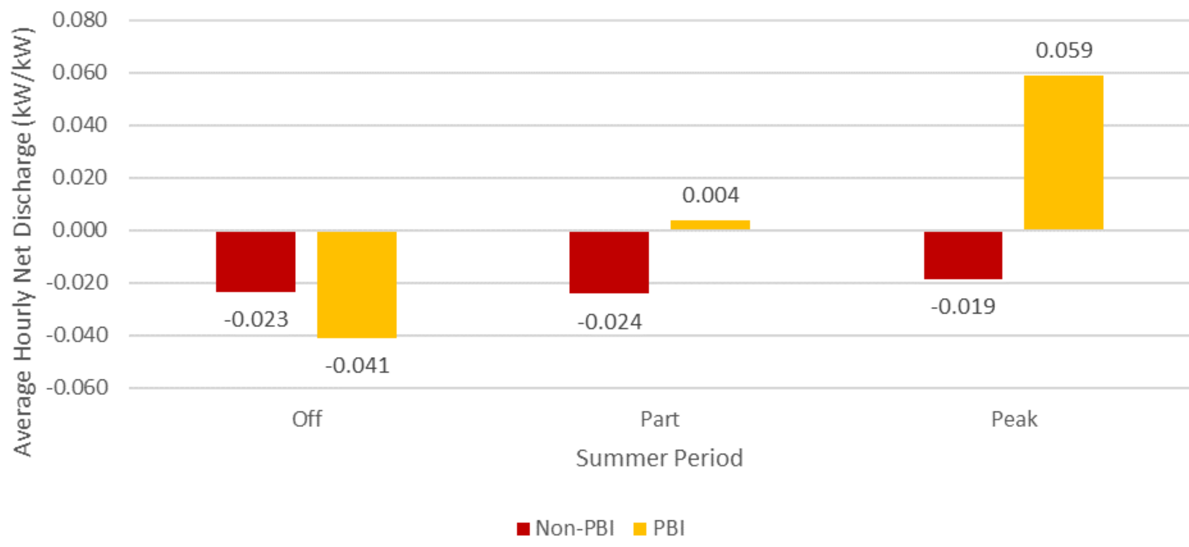
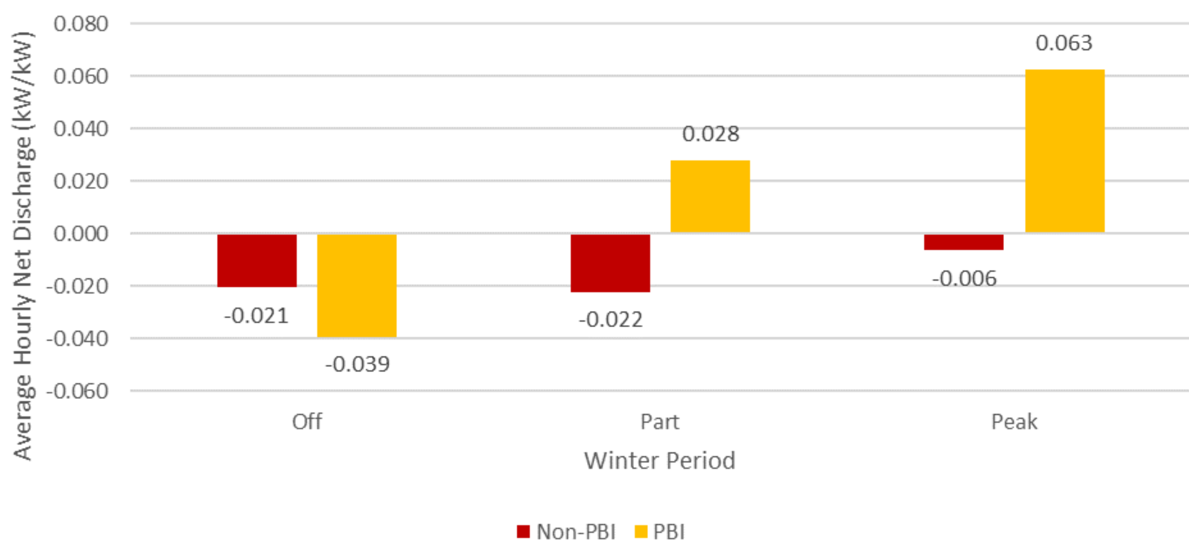


FIGURE 4-25: HOURLY NET DISCHARGE KW PER REBATED KW BY WINTER TOU PERIOD



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 4-26 and Figure 4-27 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 4-26: 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	0.012	0.009	0.008	0.019	0.021	0.023	0.028	0.050	0.060	0.063	0.059	0.057
1	0.017	0.015	0.007	0.011	0.013	0.016	0.024	0.045	0.057	0.058	0.060	0.059
2	0.010	0.008	0.004	0.011	0.014	0.016	0.025	0.046	0.058	0.061	0.059	0.057
3	0.010	0.007	0.004	0.012	0.013	0.015	0.025	0.046	0.059	0.062	0.062	0.061
4	0.010	0.008	0.004	0.005	0.005	0.004	0.017	0.021	0.028	0.025	0.057	0.061
5	0.012	0.009	0.006	0.006	0.008	0.006	0.020	0.025	0.028	0.026	0.026	0.024
6	0.024	0.018	0.013	0.018	0.018	0.016	0.025	0.032	0.036	0.033	0.032	0.024
7	0.030	0.023	0.020	0.022	0.019	0.015	0.021	0.028	0.032	0.027	0.030	0.030
8	0.031	0.026	0.029	0.031	0.025	0.018	0.025	0.034	0.040	0.036	0.027	0.027
9	0.046	0.040	0.036	0.036	0.033	0.025	0.029	0.039	0.041	0.040	0.036	0.033
10	0.045	0.041	0.043	0.036	0.042	0.032	0.037	0.052	0.045	0.048	0.040	0.036
11	0.044	0.041	0.048	0.038	0.055	0.049	0.048	0.070	0.061	0.066	0.044	0.041
12	0.040	0.041	0.051	0.043	0.057	0.052	0.050	0.075	0.064	0.071	0.050	0.043
13	0.040	0.042	0.049	0.041	0.054	0.049	0.051	0.069	0.059	0.065	0.052	0.046
14	0.040	0.041	0.043	0.037	0.064	0.067	0.073	0.081	0.077	0.068	0.048	0.044
15	0.040	0.039	0.040	0.037	0.065	0.075	0.077	0.088	0.089	0.065	0.046	0.043
16	0.045	0.042	0.055	0.062	0.070	0.084	0.081	0.097	0.096	0.073	0.049	0.056
17	0.083	0.075	0.084	0.080	0.044	0.034	0.038	0.045	0.052	0.069	0.080	0.064
18	0.104	0.096	0.118	0.110	0.062	0.045	0.056	0.058	0.071	0.082	0.084	0.073
19	0.142	0.131	0.123	0.105	0.078	0.058	0.074	0.072	0.080	0.088	0.094	0.086
20	0.141	0.132	0.081	0.059	0.053	0.047	0.057	0.057	0.064	0.057	0.076	0.085
21	0.083	0.075	0.037	0.033	0.048	0.048	0.055	0.078	0.087	0.084	0.054	0.044
22	0.019	0.016	0.018	0.038	0.042	0.043	0.055	0.079	0.081	0.086	0.075	0.068
23	0.043	0.032	0.011	0.012	0.015	0.017	0.027	0.049	0.058	0.059	0.077	0.076

FIGURE 4-27: 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	-0.185	-0.168	-0.141	-0.136	-0.132	-0.138	-0.141	-0.172	-0.184	-0.166	-0.177	-0.168
1	-0.165	-0.150	-0.113	-0.103	-0.096	-0.103	-0.106	-0.138	-0.144	-0.129	-0.154	-0.149
2	-0.121	-0.109	-0.083	-0.076	-0.067	-0.071	-0.077	-0.099	-0.110	-0.107	-0.120	-0.119
3	-0.090	-0.080	-0.058	-0.055	-0.050	-0.048	-0.055	-0.079	-0.093	-0.093	-0.097	-0.096
4	-0.063	-0.057	-0.042	-0.038	-0.039	-0.036	-0.042	-0.058	-0.072	-0.071	-0.082	-0.087
5	-0.044	-0.040	-0.028	-0.022	-0.023	-0.020	-0.028	-0.032	-0.041	-0.038	-0.059	-0.064
6	-0.031	-0.027	-0.019	-0.020	-0.021	-0.018	-0.026	-0.027	-0.034	-0.033	-0.033	-0.036
7	-0.025	-0.021	-0.021	-0.019	-0.019	-0.017	-0.024	-0.024	-0.030	-0.029	-0.032	-0.031
8	-0.023	-0.024	-0.028	-0.026	-0.025	-0.020	-0.031	-0.037	-0.041	-0.039	-0.033	-0.031
9	-0.033	-0.032	-0.028	-0.022	-0.022	-0.018	-0.027	-0.035	-0.037	-0.038	-0.039	-0.039
10	-0.035	-0.028	-0.024	-0.020	-0.019	-0.017	-0.027	-0.031	-0.036	-0.034	-0.034	-0.038
11	-0.033	-0.025	-0.023	-0.017	-0.015	-0.013	-0.022	-0.025	-0.033	-0.030	-0.031	-0.036
12	-0.028	-0.023	-0.021	-0.015	-0.012	-0.013	-0.021	-0.024	-0.031	-0.028	-0.032	-0.032
13	-0.025	-0.021	-0.020	-0.016	-0.015	-0.014	-0.025	-0.032	-0.040	-0.037	-0.032	-0.029
14	-0.024	-0.023	-0.024	-0.020	-0.021	-0.016	-0.024	-0.035	-0.040	-0.039	-0.036	-0.029
15	-0.027	-0.024	-0.032	-0.028	-0.030	-0.019	-0.023	-0.046	-0.040	-0.047	-0.036	-0.031
16	-0.029	-0.030	-0.026	-0.017	-0.030	-0.020	-0.025	-0.049	-0.038	-0.050	-0.032	-0.029
17	-0.020	-0.017	-0.024	-0.021	-0.037	-0.030	-0.039	-0.064	-0.045	-0.052	-0.026	-0.028
18	-0.024	-0.020	-0.021	-0.019	-0.028	-0.031	-0.036	-0.047	-0.038	-0.043	-0.026	-0.031
19	-0.024	-0.022	-0.031	-0.038	-0.024	-0.026	-0.029	-0.039	-0.037	-0.040	-0.033	-0.032
20	-0.041	-0.046	-0.040	-0.039	-0.036	-0.029	-0.037	-0.042	-0.045	-0.052	-0.065	-0.031
21	-0.052	-0.052	-0.093	-0.126	-0.126	-0.107	-0.120	-0.141	-0.149	-0.169	-0.076	-0.067
22	-0.155	-0.141	-0.123	-0.117	-0.124	-0.119	-0.123	-0.163	-0.178	-0.165	-0.160	-0.150
23	-0.131	-0.118	-0.138	-0.155	-0.159	-0.155	-0.163	-0.200	-0.206	-0.197	-0.159	-0.136

Non-PBI projects, conversely, exhibit more variability with regards to charging and discharging throughout the day. Figure 4-28 and Figure 4-29 convey these results. For non-PBI projects, the magnitude of charge and discharge kW within the same hour 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.

FIGURE 4-28: 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	0.018	0.015	0.011	0.021	0.024	0.027	0.027	0.023	0.016	0.012	0.007	0.006
1	0.025	0.023	0.009	0.010	0.014	0.015	0.012	0.012	0.003	0.002	0.012	0.014
2	0.008	0.010	0.002	0.010	0.011	0.012	0.011	0.012	0.003	0.001	0.001	0.002
3	0.008	0.009	0.002	0.010	0.013	0.013	0.011	0.012	0.003	0.001	0.002	0.002
4	0.008	0.009	0.003	0.005	0.005	0.004	0.003	0.005	0.004	0.005	0.004	0.006
5	0.013	0.015	0.012	0.012	0.011	0.011	0.007	0.010	0.007	0.015	0.011	0.008
6	0.028	0.025	0.021	0.014	0.017	0.018	0.011	0.015	0.010	0.011	0.016	0.015
7	0.035	0.027	0.026	0.020	0.021	0.022	0.017	0.020	0.015	0.014	0.016	0.014
8	0.031	0.033	0.033	0.028	0.029	0.034	0.027	0.028	0.020	0.020	0.018	0.015
9	0.037	0.040	0.040	0.032	0.034	0.041	0.036	0.036	0.025	0.028	0.022	0.019
10	0.038	0.042	0.046	0.033	0.047	0.060	0.052	0.054	0.032	0.038	0.028	0.019
11	0.036	0.040	0.050	0.040	0.052	0.059	0.047	0.055	0.034	0.040	0.030	0.020
12	0.037	0.044	0.051	0.043	0.052	0.059	0.048	0.053	0.032	0.045	0.032	0.022
13	0.038	0.045	0.054	0.043	0.048	0.057	0.046	0.052	0.032	0.046	0.033	0.025
14	0.035	0.040	0.049	0.036	0.038	0.051	0.039	0.046	0.028	0.039	0.028	0.026
15	0.026	0.038	0.048	0.036	0.037	0.045	0.036	0.038	0.024	0.033	0.023	0.022
16	0.026	0.037	0.057	0.059	0.034	0.051	0.044	0.036	0.023	0.027	0.023	0.032
17	0.050	0.064	0.058	0.039	0.028	0.036	0.025	0.024	0.016	0.027	0.050	0.029
18	0.045	0.055	0.056	0.040	0.021	0.023	0.018	0.022	0.015	0.020	0.037	0.025
19	0.035	0.044	0.031	0.021	0.017	0.020	0.017	0.017	0.009	0.014	0.027	0.021
20	0.021	0.024	0.012	0.010	0.007	0.009	0.009	0.009	0.005	0.009	0.015	0.018
21	0.016	0.016	0.009	0.017	0.016	0.018	0.017	0.018	0.006	0.006	0.008	0.010
22	0.011	0.013	0.005	0.013	0.013	0.015	0.013	0.016	0.004	0.004	0.006	0.006
23	0.009	0.011	0.005	0.013	0.015	0.016	0.017	0.016	0.005	0.005	0.005	0.005

FIGURE 4-29: 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	-0.036	-0.041	-0.037	-0.048	-0.050	-0.051	-0.051	-0.045	-0.040	-0.035	-0.031	-0.027
1	-0.051	-0.053	-0.033	-0.036	-0.039	-0.039	-0.039	-0.038	-0.027	-0.024	-0.034	-0.032
2	-0.035	-0.040	-0.025	-0.032	-0.035	-0.037	-0.035	-0.033	-0.024	-0.020	-0.024	-0.020
3	-0.029	-0.034	-0.022	-0.031	-0.034	-0.036	-0.033	-0.034	-0.023	-0.019	-0.021	-0.017
4	-0.028	-0.033	-0.023	-0.028	-0.031	-0.031	-0.029	-0.030	-0.023	-0.020	-0.022	-0.017
5	-0.028	-0.033	-0.024	-0.027	-0.028	-0.026	-0.024	-0.028	-0.025	-0.024	-0.023	-0.019
6	-0.033	-0.038	-0.030	-0.030	-0.032	-0.029	-0.028	-0.029	-0.025	-0.031	-0.029	-0.024
7	-0.041	-0.041	-0.041	-0.033	-0.033	-0.031	-0.029	-0.028	-0.024	-0.026	-0.032	-0.030
8	-0.040	-0.041	-0.053	-0.045	-0.042	-0.041	-0.039	-0.040	-0.034	-0.038	-0.031	-0.027
9	-0.054	-0.057	-0.058	-0.045	-0.047	-0.047	-0.043	-0.048	-0.036	-0.038	-0.044	-0.035
10	-0.057	-0.063	-0.060	-0.052	-0.051	-0.053	-0.050	-0.053	-0.042	-0.044	-0.042	-0.037
11	-0.061	-0.064	-0.063	-0.050	-0.056	-0.064	-0.062	-0.060	-0.046	-0.051	-0.048	-0.039
12	-0.062	-0.061	-0.067	-0.055	-0.058	-0.064	-0.059	-0.062	-0.047	-0.051	-0.050	-0.037
13	-0.059	-0.063	-0.064	-0.059	-0.066	-0.071	-0.063	-0.068	-0.049	-0.055	-0.052	-0.038
14	-0.060	-0.063	-0.069	-0.058	-0.068	-0.075	-0.064	-0.075	-0.050	-0.060	-0.053	-0.039
15	-0.062	-0.064	-0.071	-0.059	-0.064	-0.077	-0.065	-0.072	-0.053	-0.060	-0.052	-0.044
16	-0.057	-0.066	-0.074	-0.060	-0.064	-0.073	-0.060	-0.071	-0.051	-0.063	-0.047	-0.046
17	-0.051	-0.062	-0.077	-0.072	-0.067	-0.088	-0.072	-0.075	-0.054	-0.061	-0.044	-0.045
18	-0.057	-0.069	-0.079	-0.065	-0.061	-0.077	-0.062	-0.062	-0.045	-0.052	-0.051	-0.043
19	-0.065	-0.071	-0.084	-0.070	-0.050	-0.067	-0.051	-0.055	-0.038	-0.043	-0.055	-0.041
20	-0.071	-0.079	-0.055	-0.038	-0.039	-0.045	-0.037	-0.036	-0.026	-0.030	-0.063	-0.036
21	-0.050	-0.049	-0.043	-0.050	-0.054	-0.064	-0.058	-0.054	-0.033	-0.038	-0.037	-0.036
22	-0.048	-0.049	-0.035	-0.044	-0.049	-0.054	-0.046	-0.043	-0.029	-0.031	-0.035	-0.034
23	-0.037	-0.043	-0.031	-0.041	-0.041	-0.041	-0.039	-0.040	-0.027	-0.029	-0.031	-0.029

Figure 4-30 and Figure 4-31 below combine the discharge and charge data for both PBI and non-PBI projects. The combined results are like PBI project findings given the much more significant sizing of those systems.

FIGURE 4-30: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NONRES 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	0.012	0.009	0.020	0.022	0.024	0.028	0.037	0.040	0.039	0.035	0.033
1	0.021	0.019	0.008	0.011	0.014	0.015	0.018	0.029	0.032	0.031	0.037	0.038
2	0.009	0.009	0.003	0.010	0.012	0.014	0.018	0.030	0.033	0.032	0.032	0.031
3	0.009	0.008	0.003	0.011	0.013	0.014	0.018	0.030	0.033	0.033	0.034	0.034
4	0.009	0.009	0.004	0.005	0.005	0.004	0.011	0.014	0.017	0.016	0.032	0.035
5	0.012	0.012	0.009	0.009	0.010	0.008	0.014	0.018	0.018	0.021	0.019	0.016
6	0.026	0.021	0.017	0.016	0.018	0.017	0.019	0.024	0.024	0.023	0.024	0.020
7	0.032	0.025	0.023	0.021	0.020	0.018	0.020	0.024	0.024	0.021	0.024	0.023
8	0.031	0.029	0.031	0.030	0.027	0.025	0.026	0.031	0.031	0.028	0.023	0.021
9	0.042	0.040	0.038	0.034	0.033	0.032	0.033	0.037	0.034	0.034	0.030	0.026
10	0.042	0.042	0.045	0.035	0.044	0.045	0.044	0.053	0.039	0.043	0.034	0.028
11	0.040	0.041	0.049	0.039	0.054	0.054	0.048	0.063	0.048	0.054	0.038	0.031
12	0.039	0.042	0.051	0.043	0.055	0.056	0.049	0.065	0.049	0.059	0.041	0.033
13	0.039	0.043	0.052	0.042	0.051	0.053	0.048	0.061	0.046	0.056	0.043	0.036
14	0.037	0.041	0.046	0.036	0.052	0.060	0.058	0.065	0.054	0.054	0.038	0.036
15	0.034	0.039	0.044	0.037	0.052	0.061	0.058	0.065	0.059	0.050	0.035	0.033
16	0.036	0.040	0.056	0.061	0.053	0.068	0.064	0.069	0.062	0.051	0.037	0.045
17	0.067	0.070	0.072	0.061	0.037	0.035	0.032	0.035	0.035	0.049	0.066	0.048
18	0.076	0.077	0.089	0.078	0.043	0.035	0.038	0.042	0.045	0.053	0.062	0.051
19	0.091	0.091	0.080	0.066	0.049	0.040	0.048	0.046	0.047	0.053	0.062	0.056
20	0.084	0.082	0.049	0.036	0.031	0.029	0.034	0.034	0.036	0.034	0.047	0.054
21	0.051	0.047	0.024	0.025	0.033	0.034	0.037	0.050	0.049	0.047	0.032	0.028
22	0.015	0.015	0.012	0.026	0.029	0.030	0.036	0.050	0.045	0.047	0.042	0.039
23	0.027	0.022	0.008	0.013	0.015	0.017	0.022	0.034	0.033	0.033	0.043	0.043

FIGURE 4-31: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NONRES 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	-0.115	-0.109	-0.093	-0.095	-0.094	-0.097	-0.099	-0.113	-0.116	-0.104	-0.108	-0.101
1	-0.111	-0.105	-0.076	-0.072	-0.069	-0.073	-0.075	-0.091	-0.090	-0.079	-0.097	-0.094
2	-0.081	-0.077	-0.056	-0.055	-0.052	-0.055	-0.057	-0.069	-0.070	-0.066	-0.075	-0.073
3	-0.061	-0.058	-0.042	-0.044	-0.042	-0.043	-0.045	-0.058	-0.060	-0.058	-0.061	-0.059
4	-0.047	-0.046	-0.033	-0.033	-0.035	-0.034	-0.036	-0.045	-0.049	-0.047	-0.054	-0.054
5	-0.037	-0.037	-0.026	-0.024	-0.026	-0.023	-0.026	-0.030	-0.034	-0.031	-0.042	-0.043
6	-0.032	-0.032	-0.024	-0.025	-0.026	-0.023	-0.027	-0.028	-0.030	-0.032	-0.031	-0.030
7	-0.033	-0.030	-0.030	-0.025	-0.025	-0.024	-0.026	-0.026	-0.027	-0.028	-0.032	-0.031
8	-0.031	-0.032	-0.040	-0.035	-0.033	-0.030	-0.035	-0.039	-0.038	-0.039	-0.032	-0.029
9	-0.043	-0.044	-0.042	-0.033	-0.034	-0.031	-0.035	-0.041	-0.036	-0.038	-0.041	-0.037
10	-0.045	-0.044	-0.041	-0.035	-0.034	-0.034	-0.037	-0.041	-0.039	-0.039	-0.038	-0.038
11	-0.047	-0.043	-0.042	-0.033	-0.034	-0.037	-0.040	-0.041	-0.039	-0.040	-0.039	-0.038
12	-0.044	-0.040	-0.042	-0.033	-0.034	-0.037	-0.039	-0.042	-0.039	-0.039	-0.040	-0.034
13	-0.041	-0.040	-0.041	-0.036	-0.039	-0.041	-0.042	-0.049	-0.044	-0.045	-0.042	-0.033
14	-0.041	-0.041	-0.045	-0.037	-0.043	-0.044	-0.043	-0.054	-0.045	-0.049	-0.044	-0.034
15	-0.043	-0.042	-0.050	-0.043	-0.045	-0.046	-0.042	-0.058	-0.046	-0.053	-0.044	-0.037
16	-0.042	-0.046	-0.049	-0.037	-0.046	-0.045	-0.041	-0.059	-0.044	-0.056	-0.039	-0.036
17	-0.035	-0.038	-0.048	-0.045	-0.051	-0.057	-0.055	-0.069	-0.049	-0.056	-0.034	-0.036
18	-0.040	-0.042	-0.048	-0.040	-0.043	-0.052	-0.048	-0.054	-0.041	-0.047	-0.038	-0.037
19	-0.043	-0.044	-0.056	-0.053	-0.036	-0.045	-0.039	-0.046	-0.037	-0.041	-0.044	-0.036
20	-0.055	-0.061	-0.047	-0.039	-0.038	-0.036	-0.037	-0.040	-0.036	-0.041	-0.064	-0.033
21	-0.051	-0.051	-0.070	-0.091	-0.092	-0.087	-0.091	-0.101	-0.095	-0.107	-0.058	-0.052
22	-0.104	-0.098	-0.082	-0.083	-0.089	-0.089	-0.088	-0.107	-0.109	-0.101	-0.101	-0.096
23	-0.086	-0.083	-0.089	-0.102	-0.104	-0.102	-0.106	-0.125	-0.122	-0.117	-0.098	-0.086

While TOU arbitrage appears to be a motivation for on-peak discharge, monthly and TOU demand reduction[14] are also important behavioral drivers. We aggregated all projects (by PBI and non-PBI) and examined how storage behavior influenced hourly load by TOU period and month. For non-PBI projects, storage dispatch increased hourly load throughout the year more significantly than it reduced load (Figure 4-32). This is consistent with the lower RTEs found within the sample of projects along with the hourly charge and discharge data presented above in Figure 4-28 and Figure 4-29. These systems are continually discharging at the sub-hourly level and re-charging immediately to shave peak demand spikes. They are reducing hourly load, on average, more regularly throughout the year during peak periods (the valley in Figure 4-32 between the gray and red lines) compared to partial-peak and off-peak hours. For PBI projects, there is a significant share of hours throughout each TOU period and month where storage has no impact on hourly demand (Figure 4-33). Much like non-PBI projects, they are reducing their hourly load, on average, more substantially throughout the peak period (the valleys get deeper).

[14] Along with monthly customer peak demand charges, some rates also include an additional demand charge which corresponds to the utility tariff peak/partial-peak TOU periods.

FIGURE 4-32: HOURLY LOAD FOR NON-PBI PROJECTS BY TOU PERIOD AND MONTH

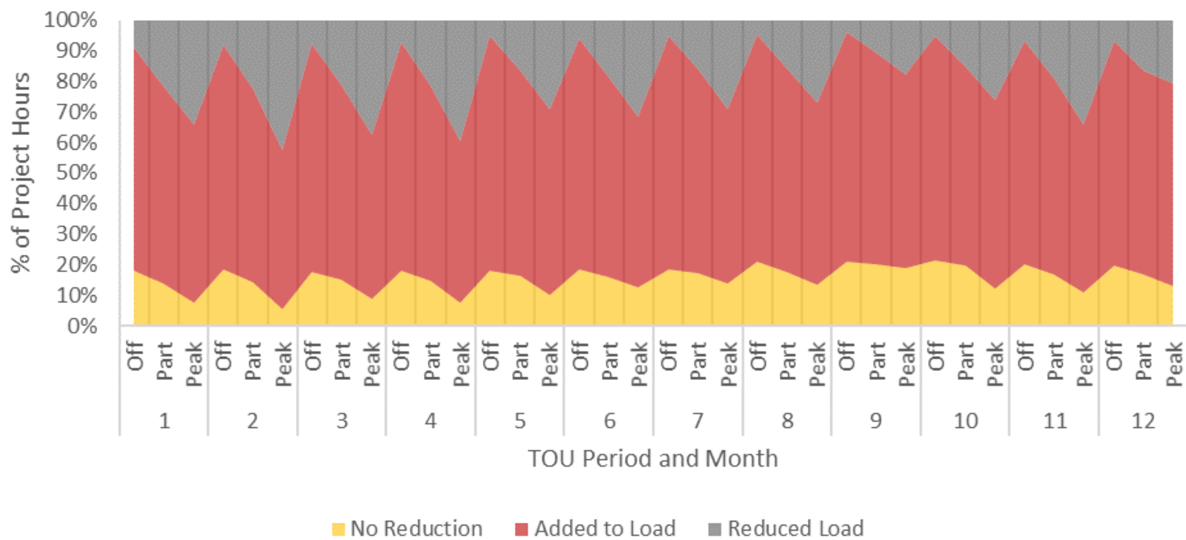
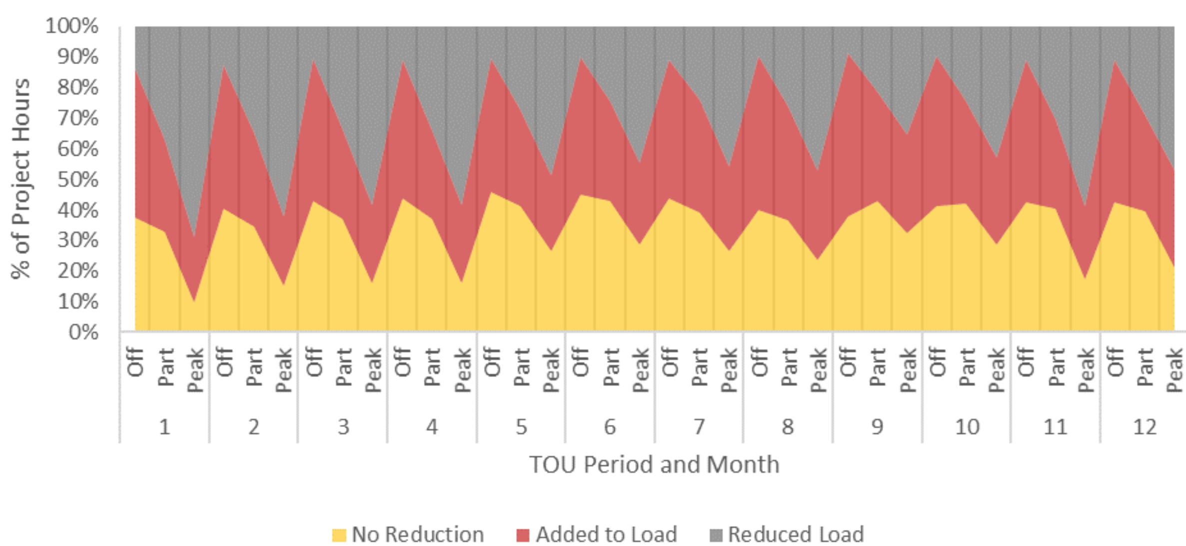


FIGURE 4-33: HOURLY LOAD FOR PBI PROJECTS BY TOU PERIOD AND MONTH



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 4-34 and Figure 4-35 convey those results. For both non-PBI and

PBI projects, storage dispatch resulted in significant reductions in monthly peak demand. For non-PBI projects, these reductions are more prominent from January through May where roughly 90% of projects (or project-months) reduced their monthly peak demand. For PBI projects, the patterns are similar, however, the percentage of projects reducing monthly peak demand is 70% to 85% throughout the year.

FIGURE 4-34: MONTHLY PEAK DEMAND FOR NON-PBI PROJECTS

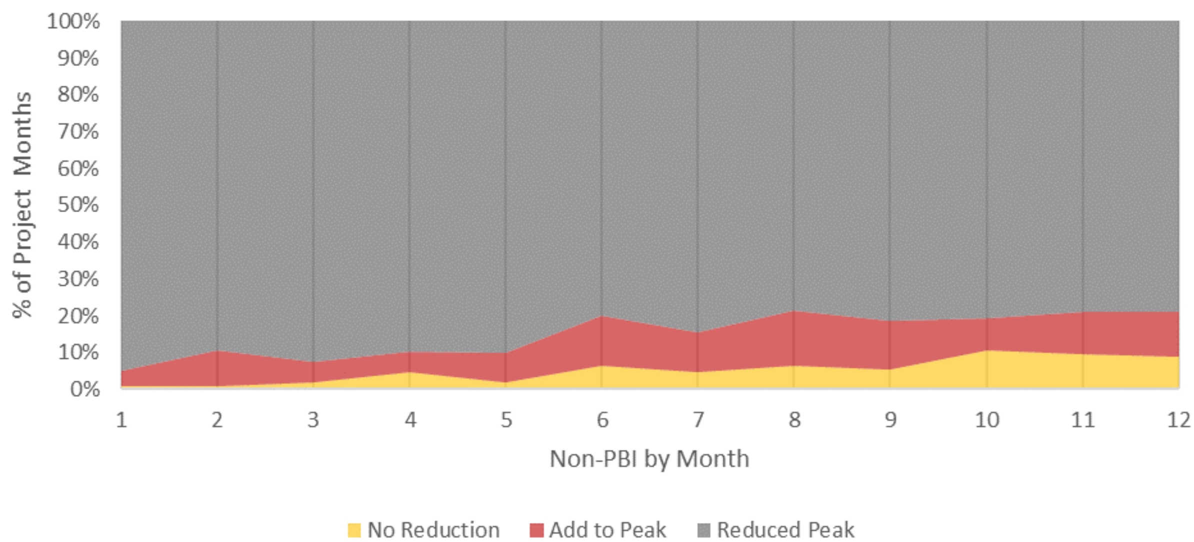
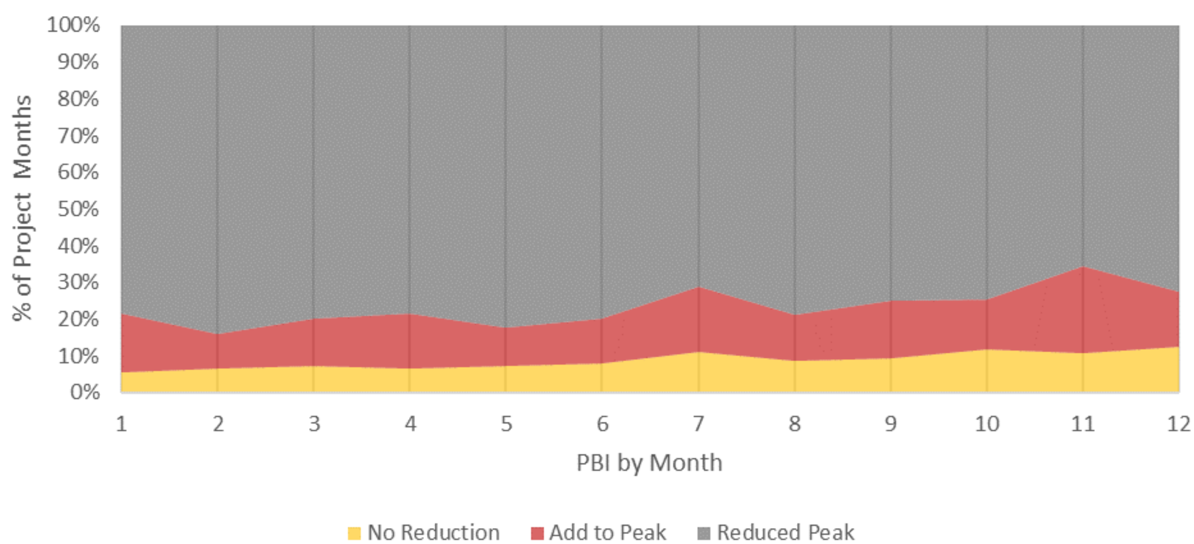


FIGURE 4-35: MONTHLY PEAK DEMAND FOR PBI PROJECTS



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, both in terms of the rebated capacity of the system and the overall reduction in demand. Figure 4-36 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 45% of SGIP rebated capacity for non-PBI projects and 18% for PBI projects.

FIGURE 4-36: MONTHLY PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

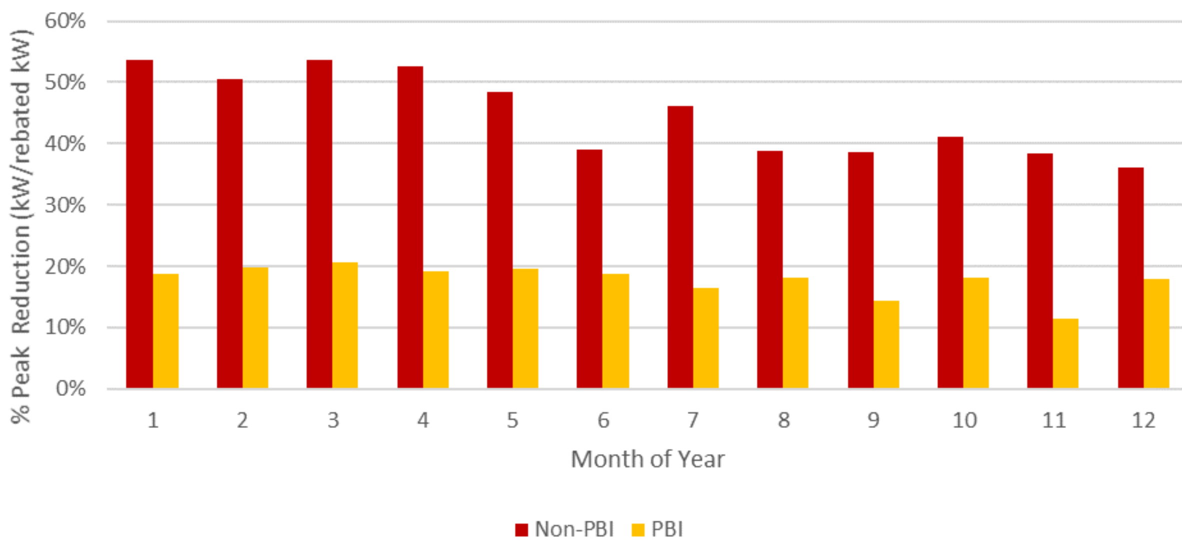


Figure 4-37 conveys the monthly average peak demand reduction as a percentage of the monthly avoided peak. In other words, if a customer's monthly peak demand would have been 100 kW in the absence of the storage system and they reduced peak demand by 10 kW with storage, then the customer reduced their peak demand by 10%. On average, PBI customers are reducing their peak demand 9% with the greatest reductions coming in the early part of the year. Non-PBI customers are reducing their peak demand by 7%.

FIGURE 4-37: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW)

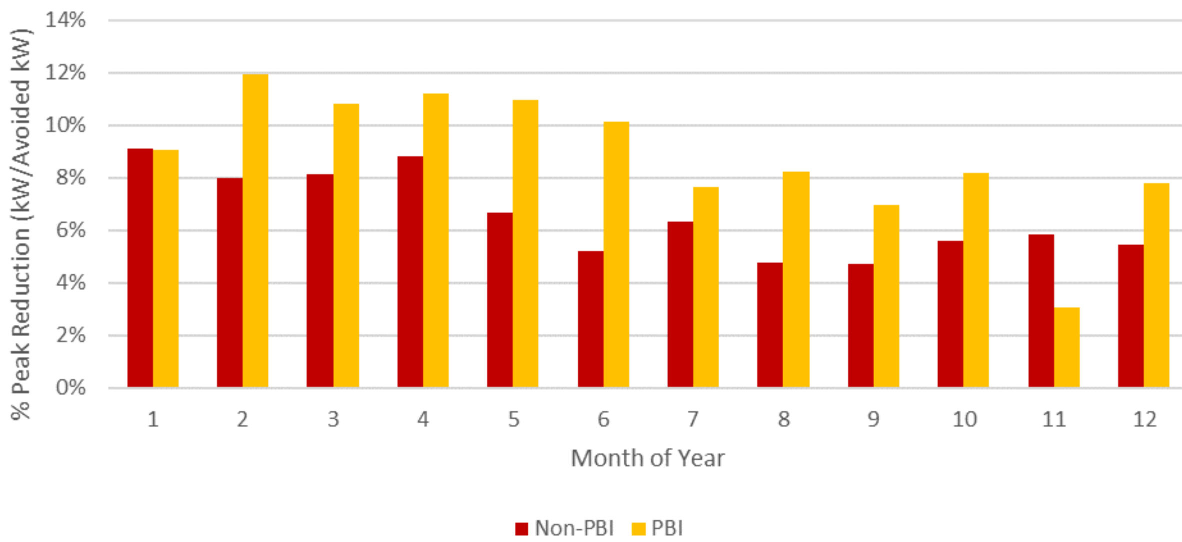
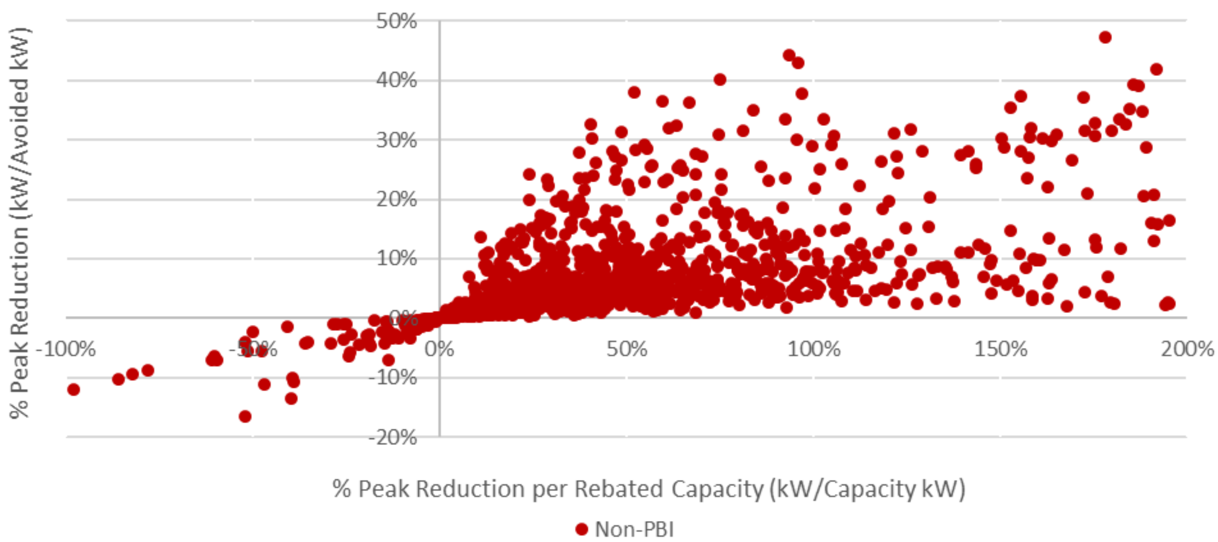


Figure 4-38 and Figure 4-39 disaggregate the data provided in the above figures for each project-month. The horizontal axis represents the monthly peak demand reduction, as a percentage of rebated capacity, for each project-month and the vertical axis represents the monthly peak demand reduction for each project relative to their avoided peak demand for that month.

While the average peak demand reduction is 45% of SGIP rebated capacity for non-PBI projects, the distribution by project-month ranges from as high as 200% to as low as a 100% increase in monthly demand. 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% to as low as -20%.

FIGURE 4-38: 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 12 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 4-39: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) PER PBI PROJECT

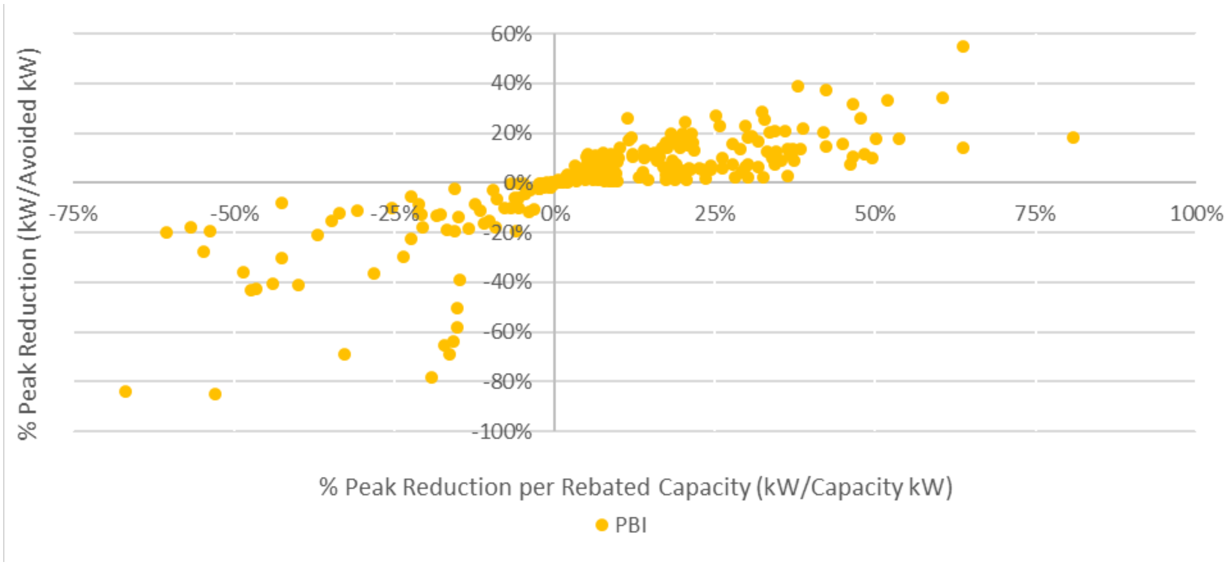


Figure 4-40 and Figure 4-41 present the rebated capacity for each system (non-PBI and PBI, respectively) relative to the size of facility load. In other words, if a storage system is sized at 50 kW (rebated capacity) and the maximum 15-minute load at that facility would have been 100 kW throughout the year, the system size relative to load would be 50%. Non-PBI systems, on average, are sized from 50% to close to 1% of facility load. Many PBI projects, however, are sized much larger than the load they are servicing.

FIGURE 4-40: PERCENT CAPACITY (KW) PER MAX ANNUAL AVOIDED PEAK (KW) FOR NON-PBI PROJECTS

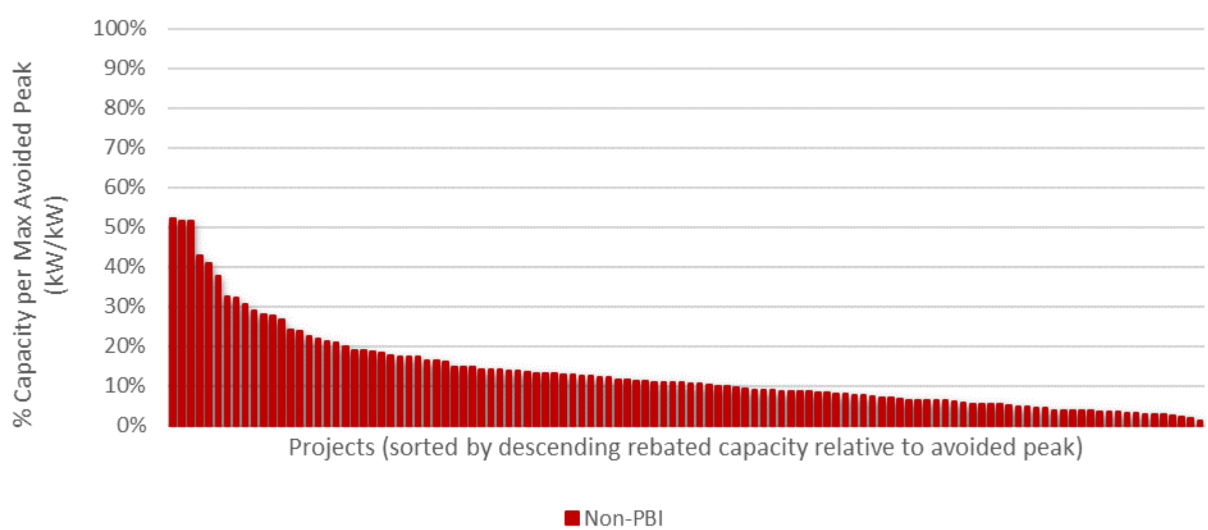
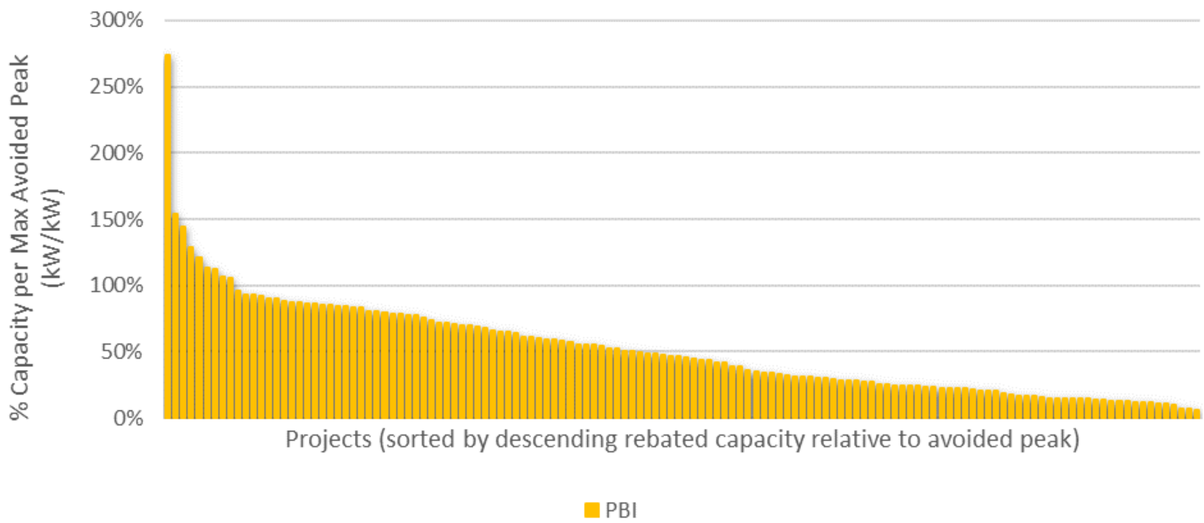


FIGURE 4-41: PERCENT CAPACITY (KW) PER MAX ANNUAL AVOIDED PEAK (KW) FOR PBI PROJECTS



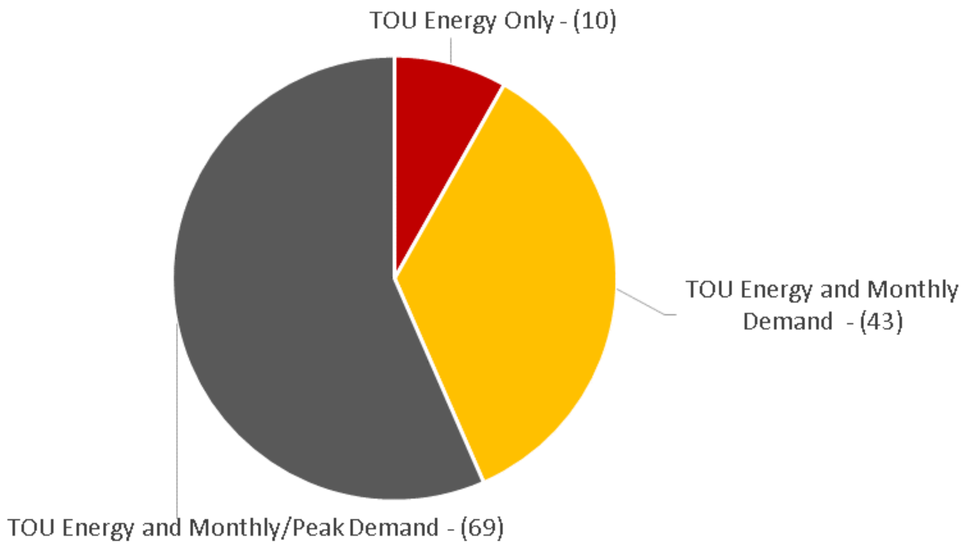
Overall Storage Dispatch Behavior by Customer Rate Group and Project Type

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 three 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
  - This rate group includes customers on an energy only tariff. They were charged a different energy rate ($/kWh) depending on the period (off-peak, partial-peak or peak hours) and season (winter or summer).
- TOU Energy with Monthly Demand
  - This rate group includes customers on a TOU energy rate as well as a monthly demand charge ($/kW). The monthly demand charge represents the highest rate of power (kW) during any 15-minute interval through each month in the year.
- TOU Energy with Monthly and Peak Demand
  - This rate group includes customers on a TOU energy rate with a monthly demand charge along with an additional demand charge incurred during a specific period (off-peak, partial-peak or peak hours) and season (winter and/or summer).

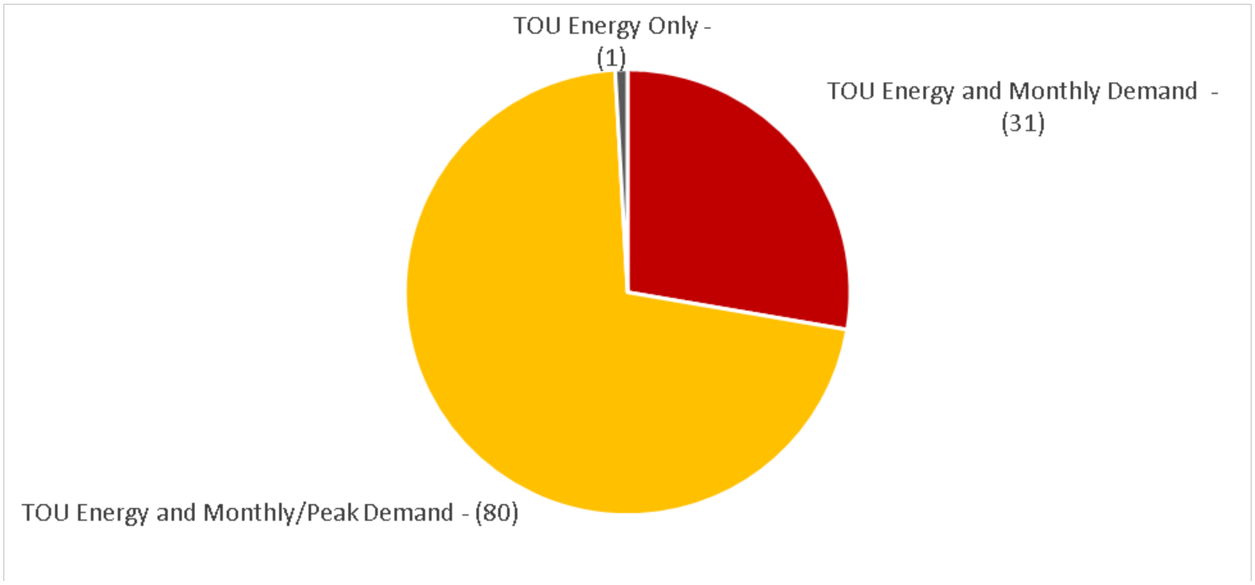
The evaluation team requested 15-minute load data and rate schedules for projects within the sample from each of the IOUs. Of the 287 nonresidential storage projects, we matched load and rate schedule data to 234 projects – 78 in PG&E, 66 in SCE and 90 in SDG&E.[15] Figure 4-42 and Figure 4-43 present the distribution of rate groups by project type. Overall, there were 10 PBI projects on a TOU energy only rate, 43 projects on a TOU and monthly demand rate and 69 on a TOU, monthly and peak demand rate. Only one non-PBI project was on a TOU energy only rate. Thirty-nine were on a TOU and monthly demand rate, and the remaining 80 non-PBI projects were on a TOU, monthly and peak demand rate.

FIGURE 4-42: RATE SCHEDULE GROUPS FOR PBI PROJECTS



[15] There was an additional project served by a municipality. We were unable to obtain rate information for that customer.

FIGURE 4-43: RATE SCHEDULE GROUPS FOR NON-PBI PROJECTS



We compared energy discharge for projects on a TOU energy rate only with those that also included a demand charge. Since a project on a TOU energy rate has no incentive to discharge during off-peak TOU periods and a customer with demand charges would be more incentivized to discharge during peak hours if their peak load was coincident with the TOU peak period, we compared the dispatch behavior for the two rate groups. There were only 11 projects on a TOU energy only rate, of which ten were PBI projects. All these projects were in PG&E territory. Figure 4-44 presents the average hourly discharge kW (per rebated capacity) for rates with energy and demand charges and Figure 4-45 presents the same results for TOU energy only rates. It's important to note that these data are presented in pacific standard time while TOU periods are defined in pacific local time.[16]

For PBI projects with demand charges there is a clear signature of discharge during both seasons – winter and summer. During the summer, average net discharge increases gradually beginning in the afternoon (2 to 3 pm) and ebbs in the evening beginning around 5 pm. During the winter, there is substantial discharge during the early evening from 5 until 9 pm.

For PBI projects on a TOU energy only rate, the discharge signature is more pronounced during the hours of 11 am to 4 pm (pacific standard time) or 12pm to 5pm local time, which coincides with the peak period.

[16] These data are presented in standard time, whereas the TOU periods presented in Figure 4-19 are presented in local time. TOU time periods begin and end one hour later during daylight savings time which occurred between 3/12 and 11/5 in 2017.

These data suggest that customers on TOU energy only rates are optimizing their bill savings with TOU arbitrage.

FIGURE 4-44: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NONRESIDENTIAL PBI PROJECTS ON A TOU ENERGY AND DEMAND RATE (PG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	0.003	0.003	0.006	0.007	0.006	0.006	0.013	0.032	0.032	0.046	0.029	0.037
1	0.006	0.006	0.005	0.002	0.001	0.001	0.011	0.029	0.030	0.039	0.031	0.036
2	0.001	0.001	0.003	0.002	0.001	0.001	0.012	0.034	0.038	0.047	0.032	0.033
3	0.001	0.001	0.003	0.002	0.002	0.002	0.013	0.035	0.038	0.050	0.044	0.053
4	0.001	0.002	0.004	0.003	0.006	0.004	0.012	0.015	0.019	0.021	0.037	0.049
5	0.003	0.002	0.007	0.009	0.016	0.008	0.016	0.024	0.023	0.025	0.019	0.022
6	0.008	0.007	0.014	0.010	0.013	0.004	0.012	0.021	0.024	0.029	0.020	0.020
7	0.021	0.013	0.009	0.012	0.012	0.007	0.009	0.010	0.017	0.020	0.020	0.030
8	0.015	0.012	0.013	0.021	0.028	0.021	0.017	0.019	0.034	0.035	0.019	0.021
9	0.030	0.027	0.019	0.019	0.028	0.020	0.017	0.019	0.029	0.028	0.040	0.034
10	0.026	0.026	0.026	0.023	0.034	0.026	0.026	0.031	0.034	0.030	0.042	0.036
11	0.027	0.030	0.032	0.030	0.062	0.047	0.039	0.053	0.060	0.052	0.047	0.048
12	0.033	0.036	0.039	0.035	0.068	0.057	0.044	0.062	0.065	0.056	0.051	0.049
13	0.037	0.042	0.042	0.040	0.070	0.051	0.050	0.062	0.064	0.057	0.053	0.054
14	0.041	0.048	0.044	0.045	0.137	0.110	0.123	0.122	0.106	0.109	0.056	0.061
15	0.047	0.056	0.046	0.055	0.164	0.144	0.143	0.146	0.128	0.126	0.056	0.058
16	0.062	0.065	0.058	0.068	0.188	0.163	0.156	0.169	0.135	0.148	0.060	0.044
17	0.069	0.063	0.120	0.144	0.078	0.065	0.078	0.081	0.075	0.084	0.060	0.054
18	0.124	0.115	0.189	0.225	0.113	0.110	0.122	0.102	0.123	0.106	0.082	0.066
19	0.185	0.183	0.229	0.245	0.139	0.131	0.152	0.129	0.152	0.131	0.112	0.086
20	0.201	0.223	0.127	0.099	0.068	0.068	0.081	0.065	0.076	0.065	0.109	0.093
21	0.093	0.094	0.055	0.012	0.010	0.014	0.020	0.036	0.038	0.052	0.057	0.042
22	0.020	0.018	0.033	0.042	0.032	0.041	0.047	0.064	0.057	0.074	0.046	0.047
23	0.063	0.057	0.019	0.002	0.001	0.002	0.012	0.029	0.030	0.039	0.052	0.063

FIGURE 4-45: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NONRESIDENTIAL PBI PROJECTS ON A TOU ENERGY ONLY RATE (PG&E)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	0.002	0.007	0.002	0.002	0.015	0.001	0.002	0.002	0.001	0.002	0.015	0.004
1	0.002	0.007	0.002	0.003	0.018	0.003	0.003	0.001	0.001	0.001	0.009	0.004
2	0.002	0.007	0.003	0.005	0.014	0.005	0.005	0.001	0.001	0.001	0.007	0.004
3	0.003	0.007	0.007	0.011	0.015	0.006	0.005	0.001	0.001	0.002	0.007	0.003
4	0.006	0.008	0.009	0.018	0.022	0.013	0.009	0.002	0.002	0.001	0.012	0.008
5	0.012	0.017	0.014	0.030	0.041	0.031	0.023	0.007	0.005	0.006	0.017	0.013
6	0.018	0.029	0.024	0.047	0.053	0.038	0.035	0.009	0.009	0.006	0.031	0.029
7	0.014	0.026	0.034	0.046	0.026	0.017	0.017	0.020	0.020	0.017	0.023	0.031
8	0.040	0.036	0.076	0.111	0.024	0.021	0.023	0.033	0.041	0.040	0.026	0.024
9	0.123	0.109	0.108	0.093	0.038	0.030	0.029	0.019	0.026	0.026	0.038	0.048
10	0.097	0.100	0.082	0.061	0.025	0.030	0.034	0.020	0.011	0.018	0.048	0.040
11	0.083	0.071	0.081	0.065	0.084	0.094	0.077	0.094	0.042	0.058	0.043	0.026
12	0.074	0.082	0.070	0.060	0.080	0.081	0.076	0.087	0.063	0.048	0.042	0.037
13	0.065	0.076	0.062	0.047	0.069	0.064	0.086	0.089	0.071	0.063	0.039	0.041
14	0.068	0.055	0.040	0.028	0.100	0.106	0.117	0.112	0.099	0.107	0.031	0.051
15	0.068	0.029	0.025	0.027	0.123	0.126	0.120	0.123	0.109	0.130	0.034	0.059
16	0.054	0.032	0.020	0.029	0.132	0.128	0.125	0.147	0.125	0.141	0.032	0.040
17	0.042	0.027	0.026	0.050	0.058	0.033	0.035	0.054	0.052	0.059	0.047	0.030
18	0.035	0.028	0.048	0.074	0.098	0.073	0.074	0.085	0.067	0.067	0.068	0.059
19	0.066	0.064	0.072	0.074	0.109	0.081	0.083	0.099	0.073	0.082	0.101	0.118
20	0.090	0.084	0.041	0.031	0.052	0.040	0.043	0.046	0.029	0.036	0.106	0.141
21	0.041	0.038	0.026	0.015	0.034	0.011	0.008	0.020	0.004	0.008	0.056	0.057
22	0.006	0.010	0.022	0.018	0.037	0.020	0.019	0.034	0.008	0.016	0.031	0.014
23	0.021	0.015	0.010	0.002	0.015	0.001	0.001	0.001	0.002	0.001	0.049	0.029

We also assessed monthly demand reduction based on the rate group for each of the projects. Customers with demand charges will likely utilize storage dispatch differently throughout the year for demand reduction than a customer on an energy-only rate. As mentioned above, customers on an energy-only rate will likely not optimize storage to reduce peak demand unless their peak demand is coincident with periods when they are paying higher energy rates.

Figure 4-46 and Figure 4-47 present the monthly peak demand reduction for PBI and non-PBI customers by rate group. The vertical axis represents the percentage reduction in monthly peak demand realized from the storage system. For non-PBI projects, there is some variation in demand reduction for customers on monthly charges only compared to those on a monthly combined with peak charge, with the latter customers generally showing somewhat higher reductions. The PBI projects on a TOU energy only rate provide more perspective. Throughout several months of the year, they are increasing their peak demand, on average. These customers are potentially saving money on their bills through TOU arbitrage and, given that there is no price signal for them to reduce demand during certain periods of time, are increasing their monthly peak demand.

FIGURE 4-46: PBI MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) BY RATE GROUP

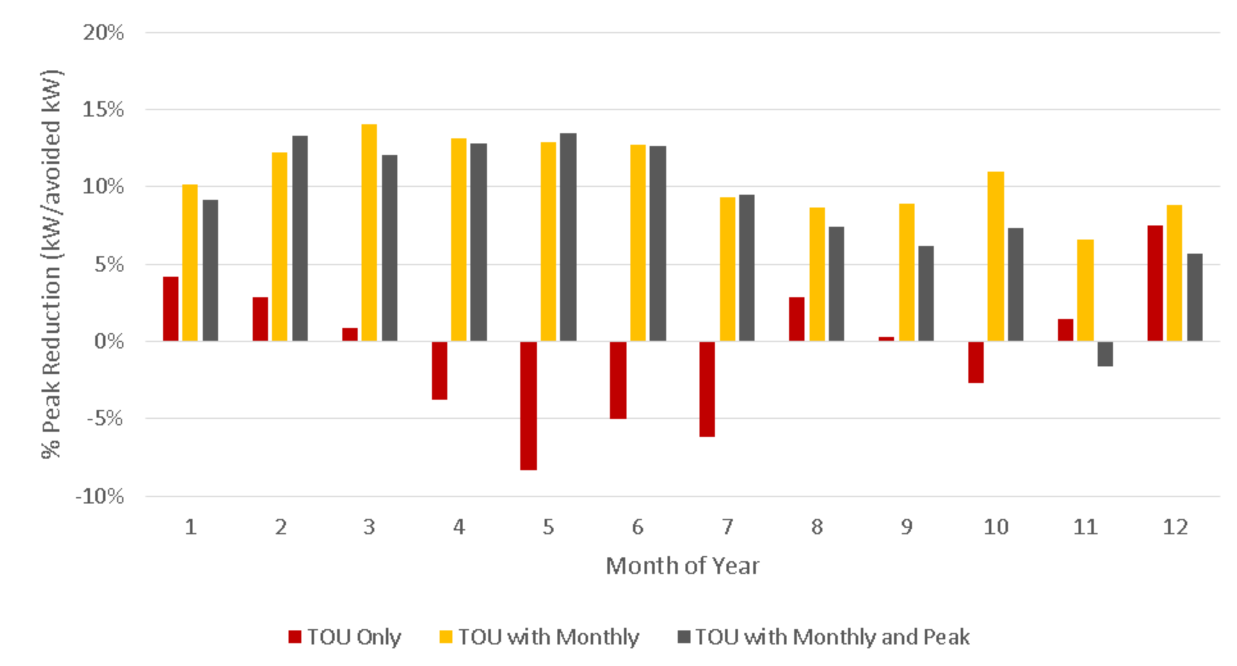
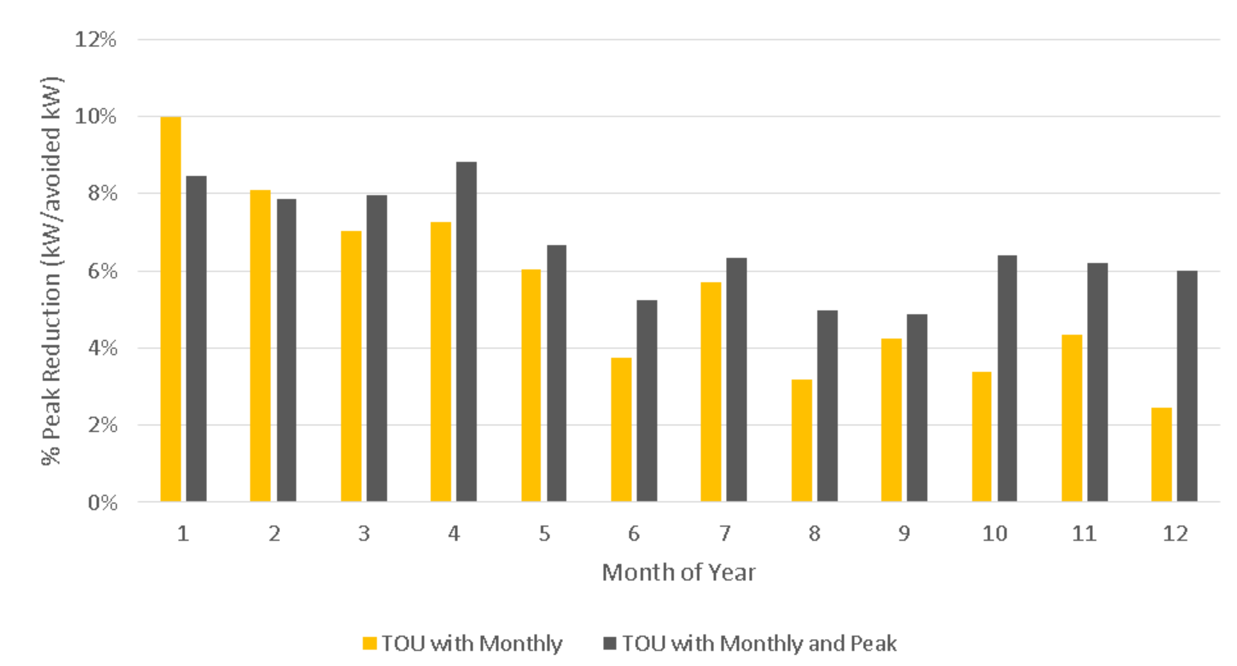


FIGURE 4-47: NON-PBI MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) BY RATE GROUP

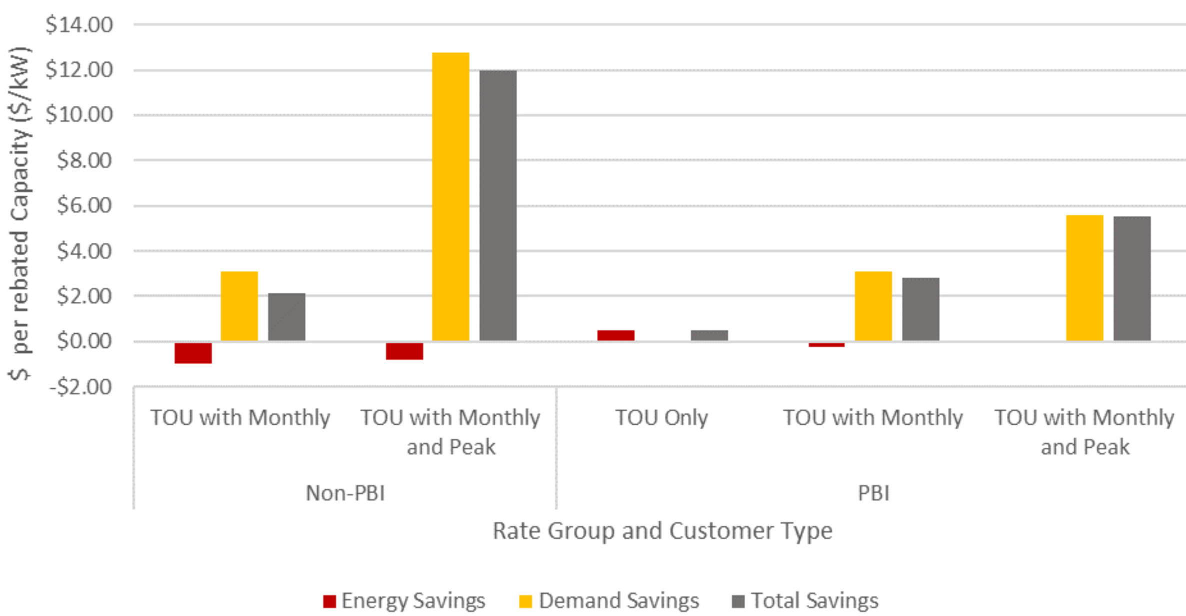


Overall Customer Bill Savings ($/kW) by Rate Group and Project Type

Finally, 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 4-48 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.

For both non-PBI rate groups, customers incurred energy costs, on average, by utilizing their storage systems. Both the monthly demand and the monthly demand with peak groups realized significant savings by optimizing their storage to reduce peak and/or monthly demand. PBI projects on a TOU energy only rate realized energy savings from the storage systems which suggests they were optimizing dispatch for TOU arbitrage. PBI customers with demand charges realized savings from demand reduction, while energy charges had a negligible effect on their bill.

FIGURE 4-48: CUSTOMER BILL SAVINGS ($/KW) BY RATE GROUP AND PBI/NON-PBI



4.3.2 Residential Customer Impacts

For the 28 projects for which data are available, we've conducted a high-level assessment of how residential storage systems are being utilized throughout the day and year. Figure 4-49 and Figure 4-50 convey those findings. These projects generally discharge from late morning starting at 11am until midafternoon at about 4 pm. They are consistently charging directly after this period, from 4 pm until midnight.

FIGURE 4-49: 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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
11	0.053	0.053	0.049	0.041	0.046	0.053	0.036	0.038	0.047	0.081	0.139	0.158
12	0.052	0.052	0.046	0.066	0.072	0.078	0.060	0.063	0.059	0.087	0.139	0.158
13	0.052	0.050	0.046	0.065	0.073	0.077	0.060	0.062	0.053	0.035	0.022	0.055
14	0.052	0.050	0.046	0.067	0.075	0.079	0.062	0.063	0.053	0.034	0.017	0.054
15	0.034	0.040	0.039	0.063	0.066	0.070	0.057	0.055	0.040	0.028	0.016	0.044
16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.012	0.040
17	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

FIGURE 4-50: 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	-0.007	-0.010	-0.013	-0.012	-0.012	-0.010	-0.010	-0.010	-0.009	-0.008	-0.006	-0.007
1	-0.007	-0.009	-0.011	-0.010	-0.010	-0.009	-0.011	-0.009	-0.008	-0.008	-0.007	-0.006
2	-0.007	-0.009	-0.011	-0.009	-0.010	-0.009	-0.010	-0.009	-0.008	-0.009	-0.007	-0.007
3	-0.006	-0.010	-0.010	-0.008	-0.009	-0.009	-0.009	-0.008	-0.010	-0.009	-0.007	-0.007
4	-0.006	-0.009	-0.009	-0.009	-0.009	-0.009	-0.008	-0.009	-0.008	-0.008	-0.007	-0.007
5	-0.005	-0.007	-0.009	-0.009	-0.009	-0.010	-0.009	-0.010	-0.008	-0.009	-0.007	-0.008
6	-0.005	-0.008	-0.010	-0.010	-0.010	-0.011	-0.009	-0.010	-0.011	-0.009	-0.008	-0.007
7	-0.007	-0.009	-0.010	-0.010	-0.011	-0.011	-0.009	-0.010	-0.010	-0.009	-0.008	-0.007
8	-0.007	-0.008	-0.009	-0.009	-0.009	-0.010	-0.009	-0.011	-0.008	-0.010	-0.007	-0.007
9	-0.006	-0.008	-0.010	-0.009	-0.009	-0.009	-0.009	-0.010	-0.009	-0.010	-0.008	-0.007
10	-0.006	-0.008	-0.009	-0.009	-0.010	-0.010	-0.010	-0.009	-0.009	-0.009	-0.007	-0.008
11	-0.005	-0.006	-0.008	-0.008	-0.009	-0.008	-0.008	-0.008	-0.007	-0.005	-0.003	-0.001
12	-0.004	-0.006	-0.009	-0.008	-0.008	-0.008	-0.009	-0.007	-0.006	-0.006	-0.003	-0.001
13	-0.005	-0.007	-0.008	-0.008	-0.007	-0.008	-0.010	-0.008	-0.010	-0.028	-0.053	-0.045
14	-0.005	-0.006	-0.008	-0.008	-0.007	-0.008	-0.009	-0.008	-0.015	-0.060	-0.129	-0.110
15	-0.006	-0.007	-0.010	-0.008	-0.008	-0.010	-0.009	-0.011	-0.021	-0.064	-0.133	-0.115
16	-0.046	-0.047	-0.048	-0.050	-0.054	-0.061	-0.046	-0.045	-0.049	-0.038	-0.038	-0.043
17	-0.044	-0.047	-0.045	-0.055	-0.060	-0.064	-0.051	-0.052	-0.051	-0.033	-0.019	-0.037
18	-0.043	-0.044	-0.042	-0.054	-0.060	-0.064	-0.051	-0.052	-0.050	-0.038	-0.023	-0.063
19	-0.042	-0.044	-0.041	-0.060	-0.063	-0.070	-0.058	-0.061	-0.057	-0.052	-0.040	-0.094
20	-0.041	-0.044	-0.042	-0.060	-0.066	-0.069	-0.054	-0.052	-0.042	-0.039	-0.033	-0.078
21	-0.040	-0.043	-0.043	-0.059	-0.065	-0.069	-0.054	-0.054	-0.041	-0.036	-0.030	-0.074
22	-0.038	-0.041	-0.039	-0.051	-0.058	-0.058	-0.048	-0.049	-0.041	-0.032	-0.025	-0.061
23	-0.021	-0.027	-0.026	-0.039	-0.036	-0.033	-0.029	-0.029	-0.022	-0.015	-0.009	-0.011

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 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 2017 for both the CAISO system[17] as well as the three IOUs.

4.4.1 Nonresidential System Impacts

Figure 4-51 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 180 of the top 200 hours and therefore increasing coincident peak demand during those hours. These results are consistent with findings from the 2016 SGIP Advanced Energy Storage Impact Evaluation, both in terms of the magnitude of average net discharge kW throughout the top 200 hours in 2016 and the number of hours where SGIP AES projects were increasing coincident peak demand (165 of 200 hours in 2016[18]).

FIGURE 4-51: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS FOR NON-PBI PROJECTS

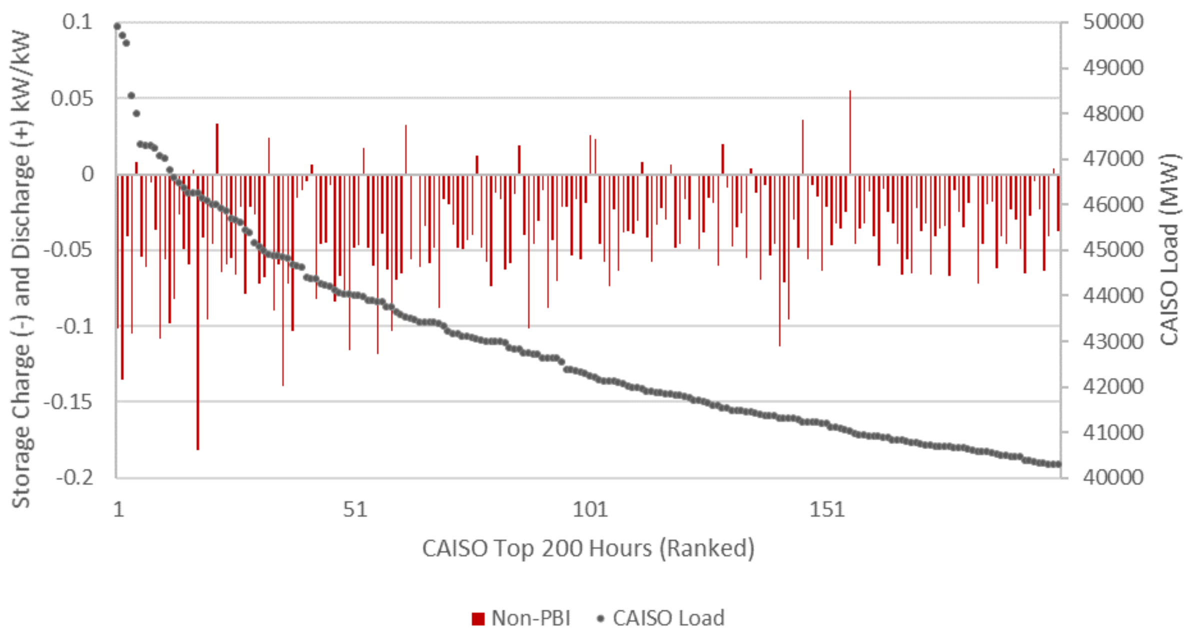


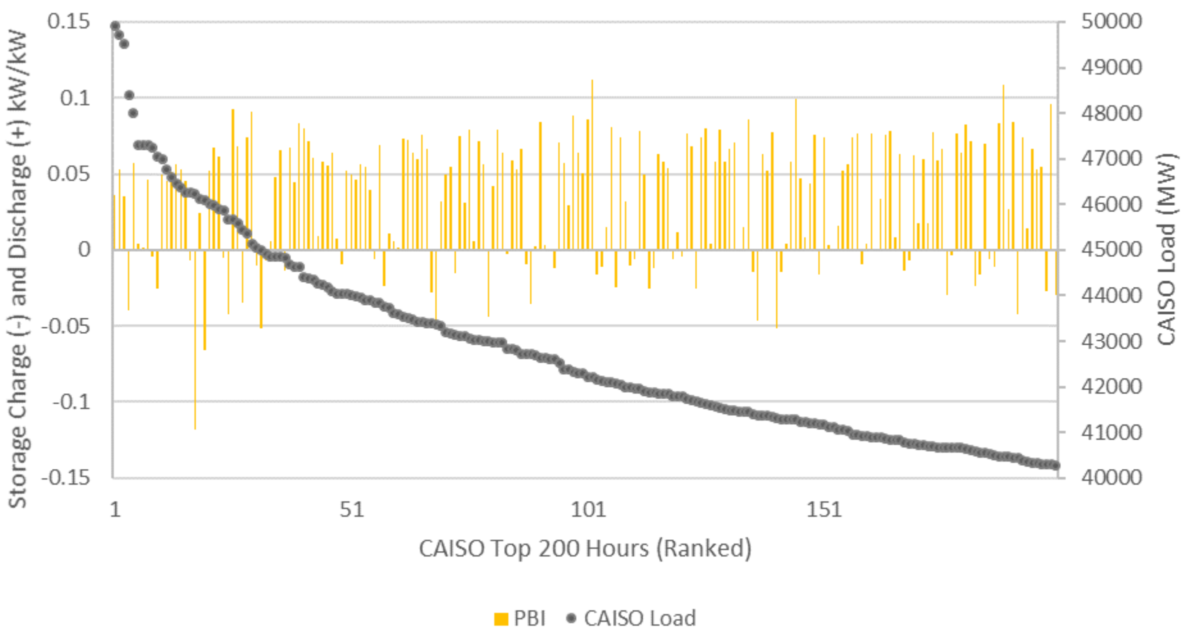
Figure 4-52 presents the average kW discharge per rebated capacity for PBI projects along with the peak MW for each of the top 200 CAISO hours. PBI projects were discharging throughout 145 of the top 200

[17] The top 200 CAISO peak hours all fall within June and September, beginning on 6/19 and ending on 9/12. The top CAISO load hour was on 9/1 at 3 pm (PST). The top 5 CAISO load hours occurred on that day (1 pm through 5 pm).

[18] It's important to note, CAISO peak hours in 2016 are different from peak hours in 2017. For example, the top CAISO load hour in 2016 was on 7/27 at 3 pm (PST), whereas the top load hour in 2017 was 9/1 at 3 pm (PST).

CAISO peak hours and therefore contributing to coincident peak demand reduction. These results, however, are less consistent with findings from the 2016 SGIP Advanced Energy Storage Impact Evaluation, both in terms of the magnitude of average net discharge kW throughout the top 200 hours in 2016 and the number of hours where SGIP AES projects were contributing to coincident peak demand reduction (188 of 200 hours in 2016).

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



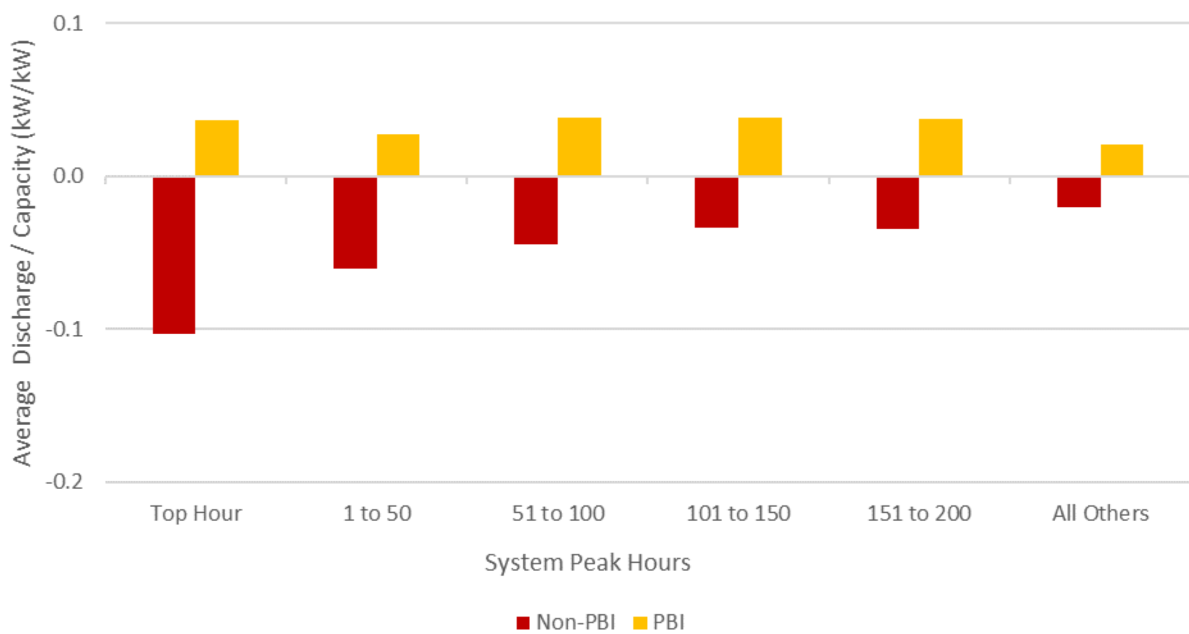
We also examined how the average net discharge throughout the top 200 system peak hours (2017) compared to the average across the remaining hours within the summer. All 200 system peak hours occurred within June and September (inclusive) and within utility peak and partial-peak TOU periods, so we have defined summer within that context.[19]

Figure 4-53 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 0.04 kW per kW rebated capacity during the CAISO peak hour. Non-PBI projects, however, are charging roughly 0.10 kW per kW rebated capacity during that hour. A similar trend is evident across the other bins. PBI storage systems are discharging, on average, throughout all other summer hours defined

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

as peak or partial-peak by TOU periods. Non-PBI projects are, on average, charging throughout those hours.

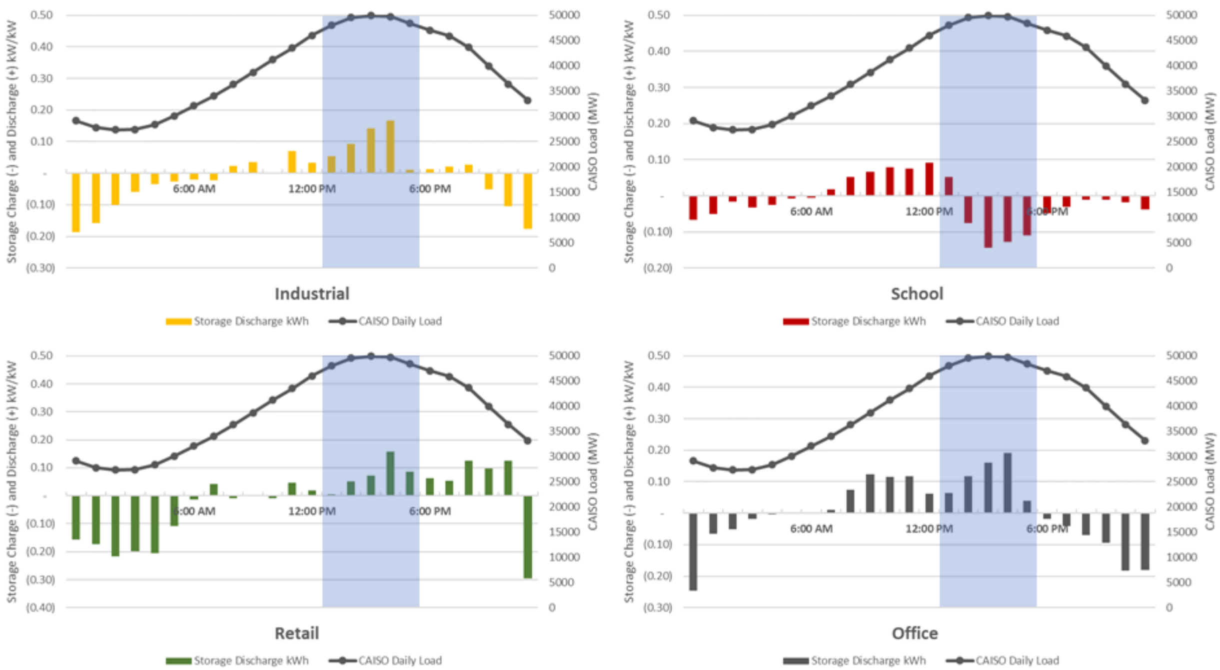
FIGURE 4-53: NET DISCHARGE KWH PER REBATED CAPACITY KW DURING CAISO PEAK HOURS FOR ALL PROJECTS WITH SUMMER AVERAGE



In 2016, PBI projects were discharging 0.22 kW and 0.15 kW per kW rebated capacity during the CAISO top hour and the top 50 hours, respectively. As evidenced above, the magnitude of that average discharge has decreased considerably in 2017. While the peak CAISO load hours differ across years, the makeup of the PBI population has changed considerably since 2016. In 2016, the top 200 CAISO hours occurred prior to October. Sixteen projects received their upfront payment in the final 3 months of that year. Furthermore, 62 additional projects received upfront payments in 2017 and were not subject to evaluation in 2016. Of those 78 total projects, 34 are primary and secondary schools.

Figure 4-54 presents the average storage discharge profiles of four facility types on September 1, 2017. The five top CAISO hours occurred within that day from 1 pm through 5 pm (PST) and are highlighted in light blue. The CAISO load profile is also overlaid in the figure. These facility types include (clockwise from top left), industrial facilities, schools, offices and retail establishments and represent 43%, 18%, 9% and 7%, respectively – or collectively, 77% – of the total 2017 rebated capacity for PBI projects. Schools are the only facility type, on average, charging throughout the top 5 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.

FIGURE 4-54: STORAGE DISCHARGE KW ON SEPTEMBER 1, 2017



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 4-55 and Figure 4-56, respectively. The results are much like those on 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. 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.

One striking difference across utility top peak loads throughout 2017 is the average net charge of storage systems operating in SDG&E territory. As presented above in Figure 4-54, schools were generally charging throughout CAISO peak hours (many of which were coincident with SDG&E system load) after discharging throughout the morning hours. Of the 43 PBI school storage systems, 21 were operating within SDG&E service territory in 2017. These systems combined represent 6.4 MW of rebated capacity or roughly 50% of the total rebated capacity for PBI systems operating in SDG&E territory.

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

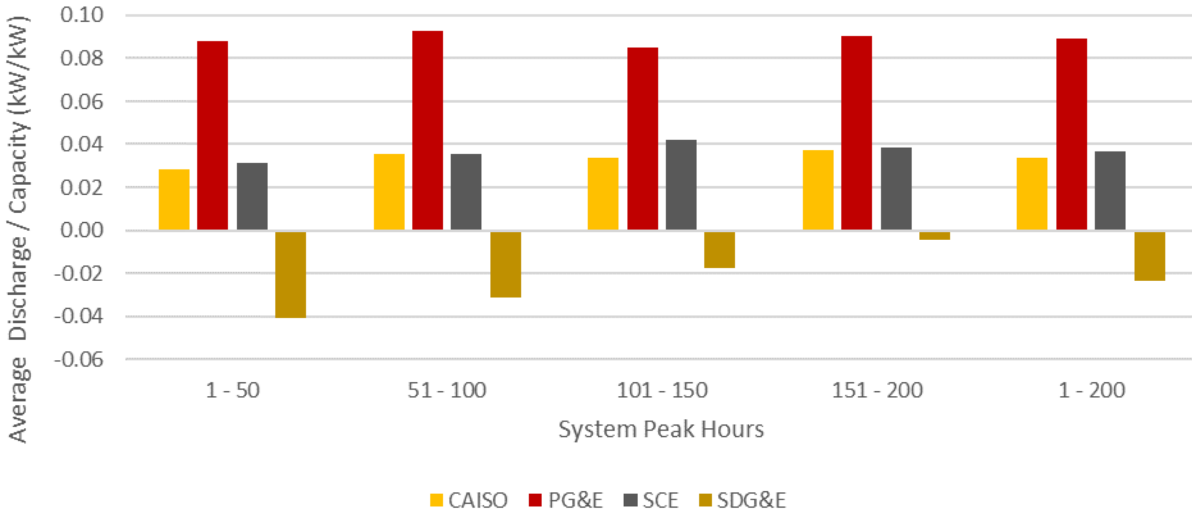
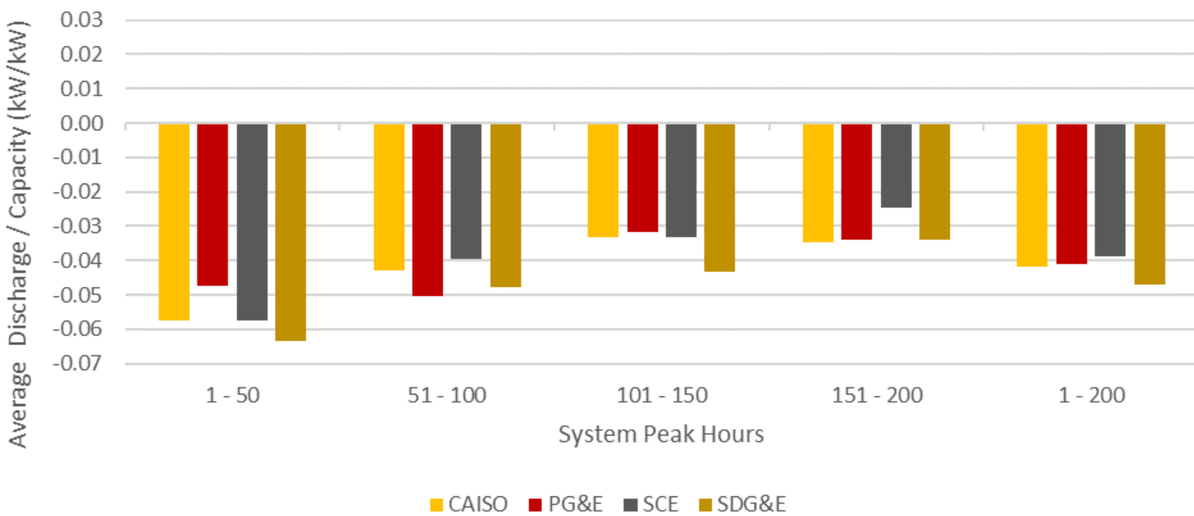


FIGURE 4-56: NET DISCHARGE KWH PER REBATED CAPACITY KW DURING SYSTEM PEAK HOURS FOR NON-PBI PROJECTS



4.4.2 Residential System Impacts

Figure 4-57 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 far less consistent than nonresidential projects. During summer months (which coincide with the CAISO peak hours), the sample of residential projects were either mostly idle or cycling throughout the daytime hours (Figure 4-11). The charging and discharging patterns associated with those cycling events were likely coincidental to system peak hours. This is evident in Figure 4-58. The average net discharge during the CAISO peak hour was positive, however, across the top 50 hours these systems were charging on average.

FIGURE 4-57: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS FOR RESIDENTIAL PROJECTS

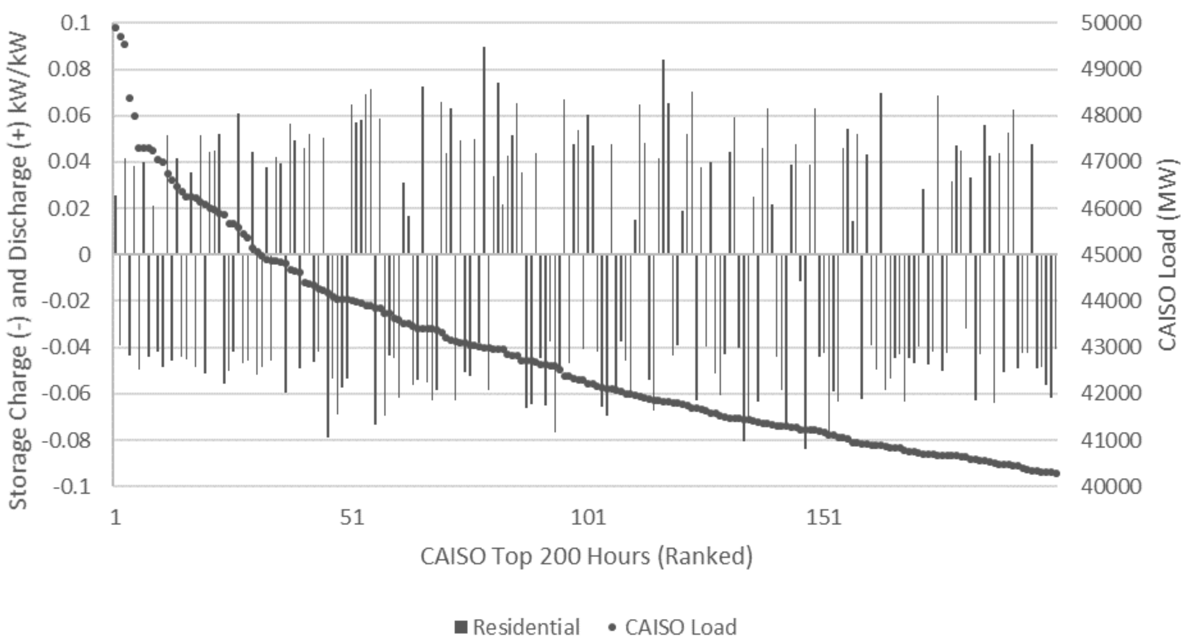
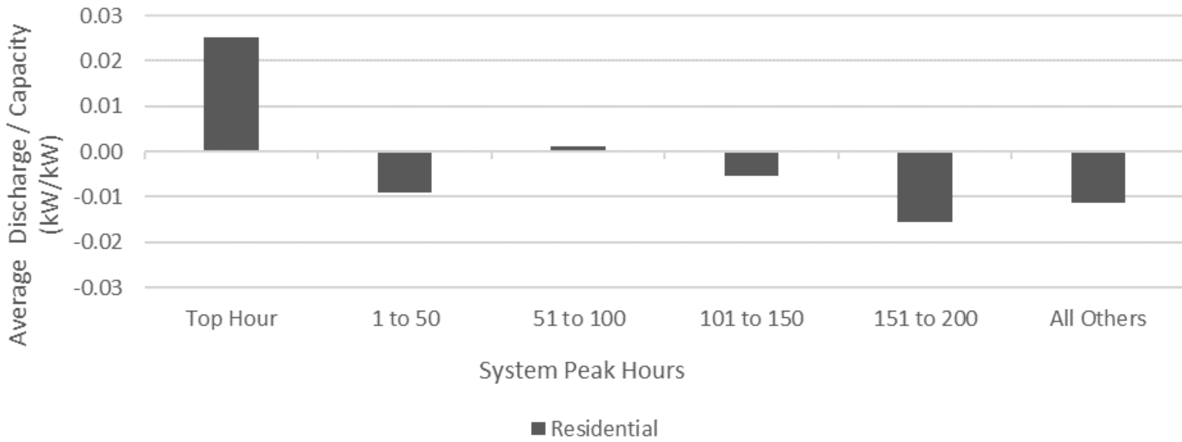


FIGURE 4-58: NET DISCHARGE KWH PER REBATED CAPACITY KW DURING CAISO PEAK HOURS FOR RESIDENTIAL PROJECTS WITH SUMMER AVERAGE



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 CO_2 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 system operators 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.

4.5.1 Nonresidential Environmental Impacts

Figure 4-59 and Figure 4-60 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 113 of 114 non-PBI projects and 118 of 134 PBI projects.

FIGURE 4-59: NET CO2 EMISSIONS PER REBATED CAPACITY FOR NON-PBI PROJECTS

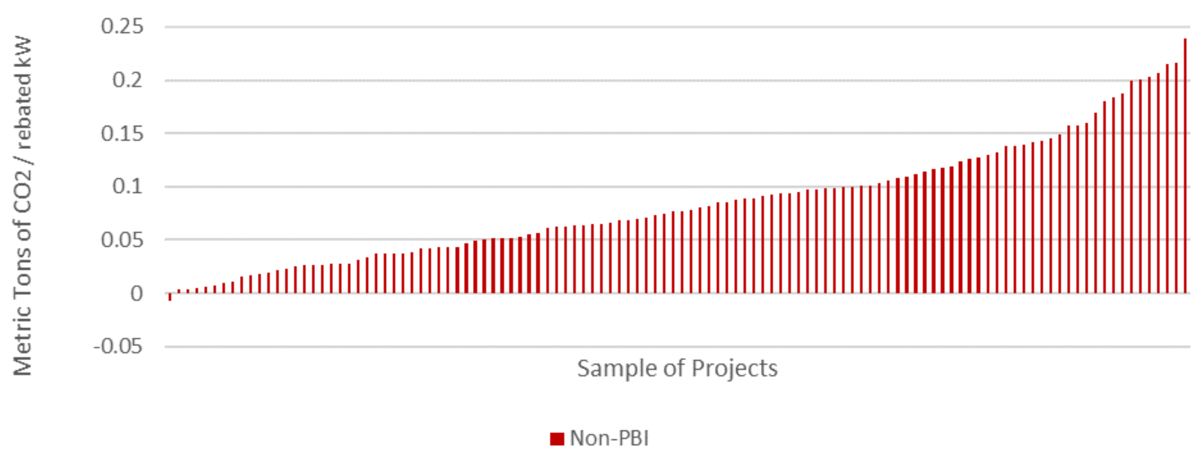


FIGURE 4-60: NET CO2 EMISSIONS PER REBATED CAPACITY FOR PBI PROJECTS

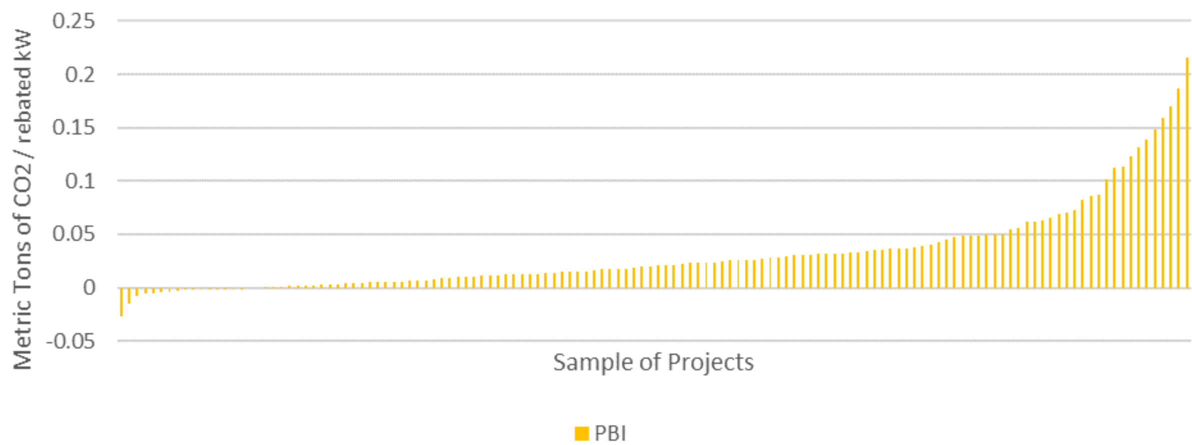
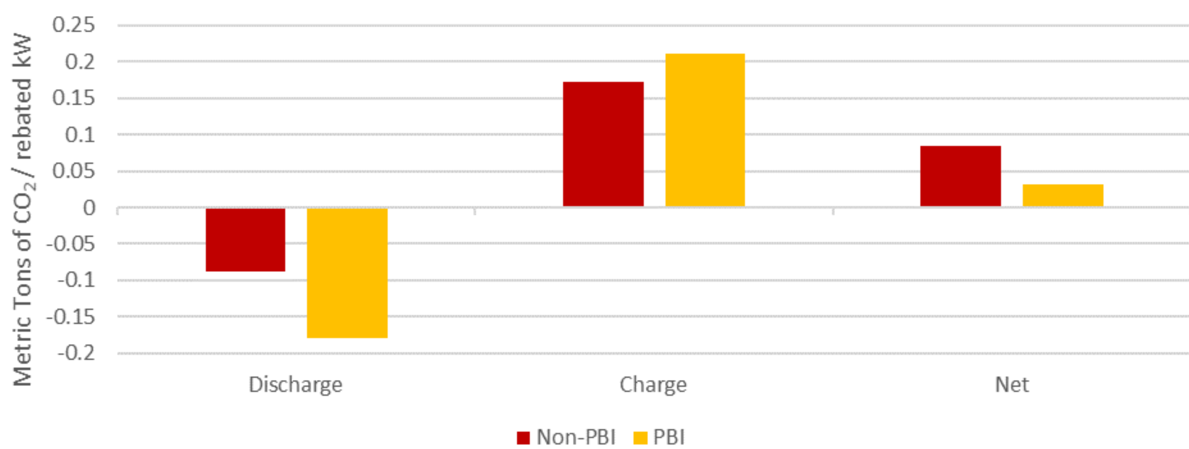


Figure 4-61 shows that, on average, both PBI and non-PBI projects are increasing emissions due to a combination of losses due to inefficiencies and less than ideal operation timing. The magnitude of normalized emissions for non-PBI projects is more significant overall.

FIGURE 4-61: 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 4-62 and Figure 4-63 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% 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 912 metric ton increase compared to a 221 metric ton increase), the influence of parasitic losses is far less consequential (roughly 0.2% of total GHG increases).

FIGURE 4-62: WATERFALL OF TOTAL CO2 IMPACTS FOR NON-PBI PROJECTS (INCLUDING PARASITIC INFLUENCE)

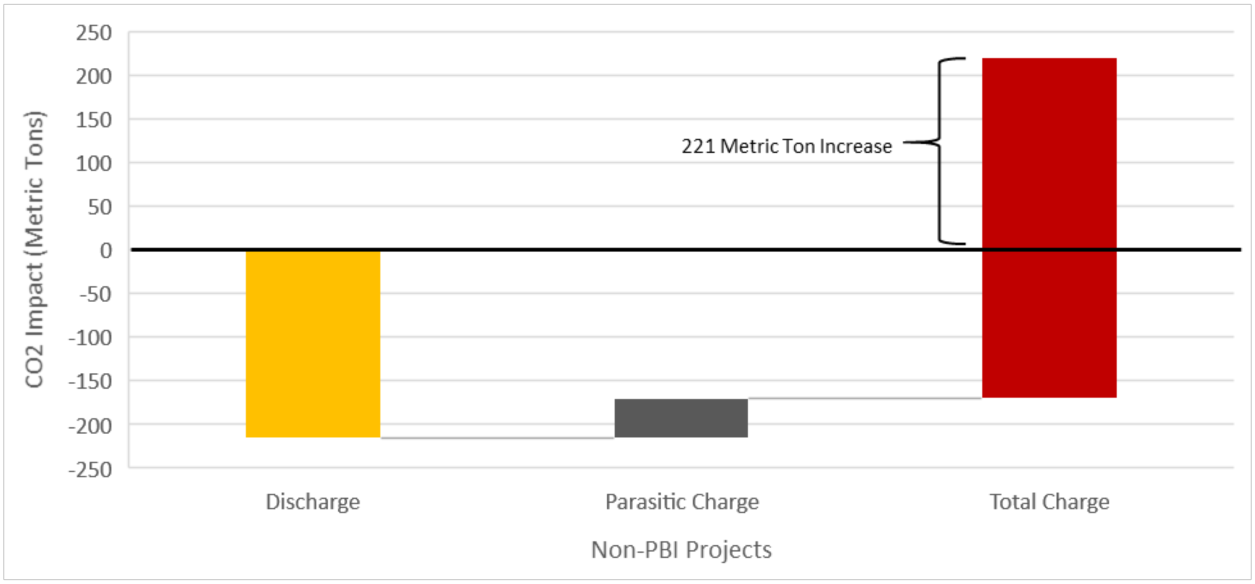
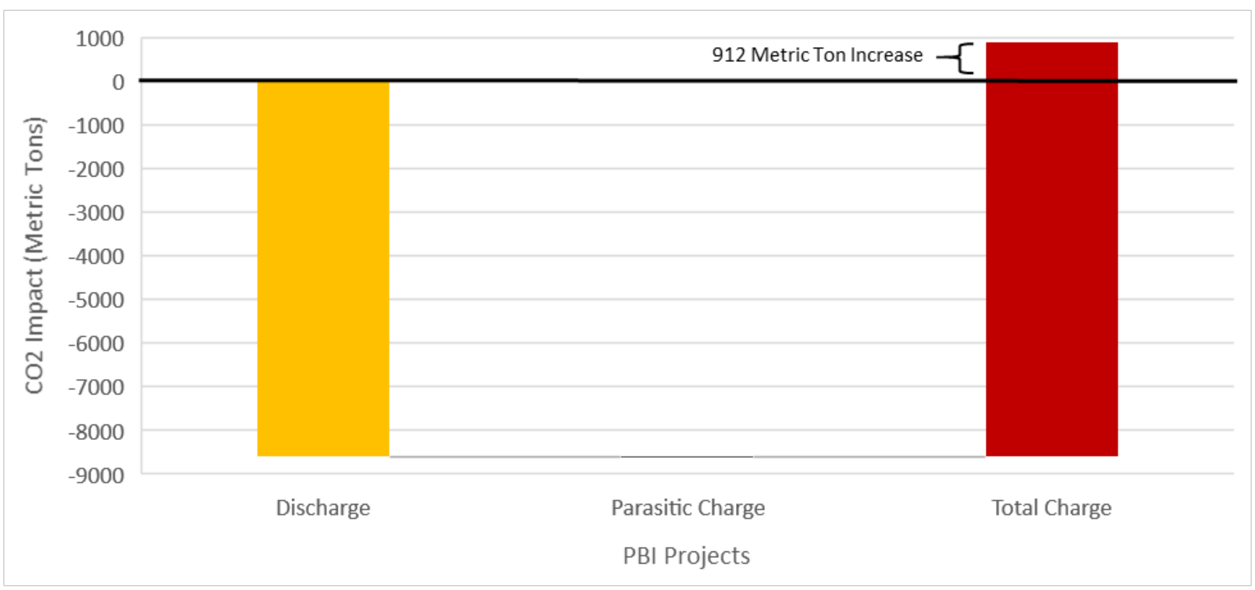


FIGURE 4-63: WATERFALL OF TOTAL CO2 IMPACTS FOR PBI PROJECTS (INCLUDING PARASITIC INFLUENCE)



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 4-64 and Figure 4-65.

FIGURE 4-64: AVERAGE PM_{10} EMISSIONS PER REBATED CAPACITY FOR NONRESIDENTIAL PROJECTS

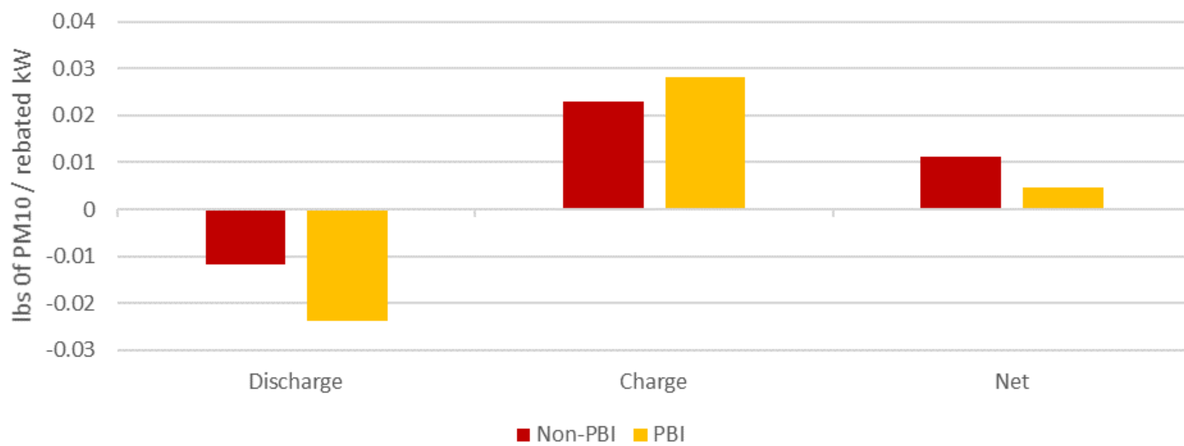


FIGURE 4-65: AVERAGE NOX EMISSIONS PER REBATED CAPACITY FOR NONRESIDENTIAL PROJECTS

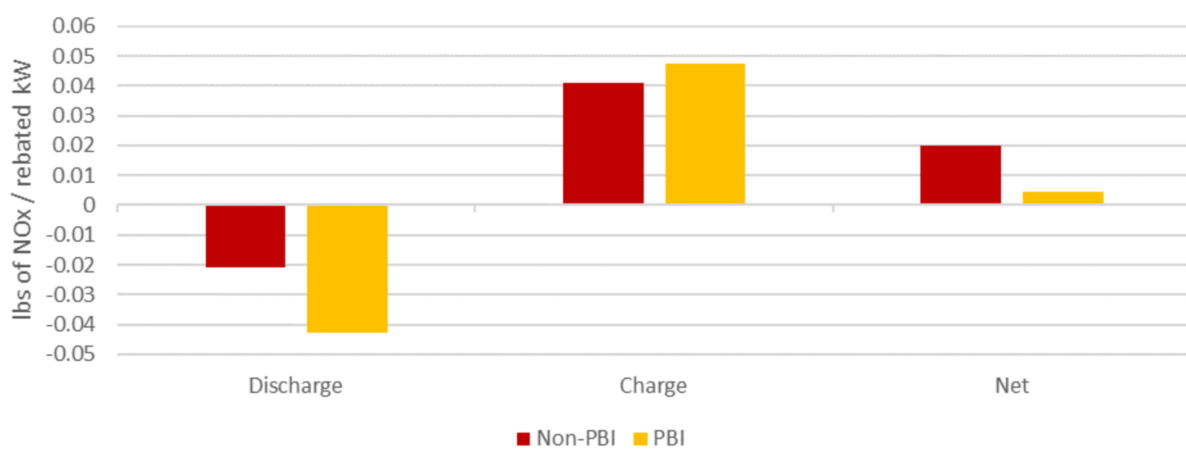


Figure 4-66 through Figure 4-69 display the average daily net discharge for non-PBI and PBI projects (for the summer and winter periods) along with the average marginal CO_2 emissions shape. In the summer, marginal emissions are highest during morning and late afternoon ramps (as renewable generation 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 4-66: NON-PBI NET DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR SUMMER

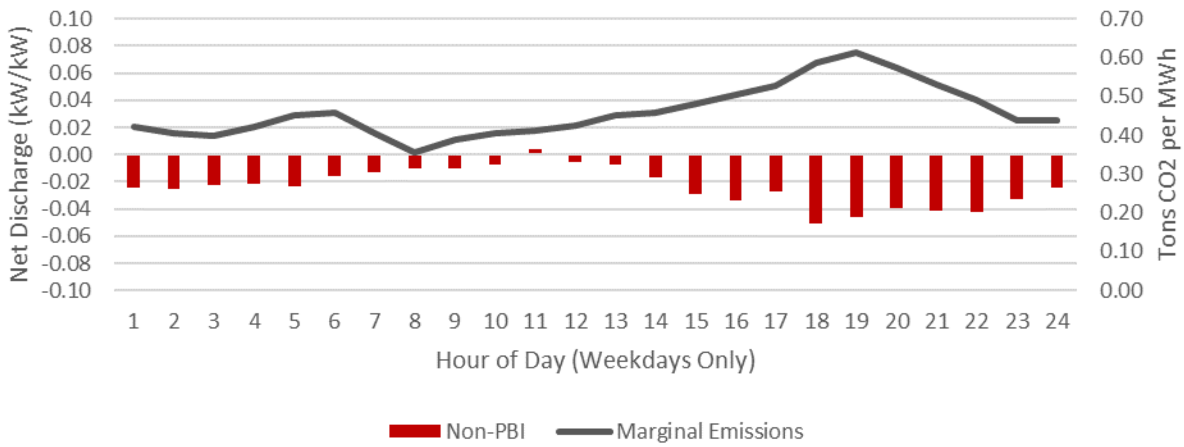


FIGURE 4-67: PBI NET DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR SUMMER

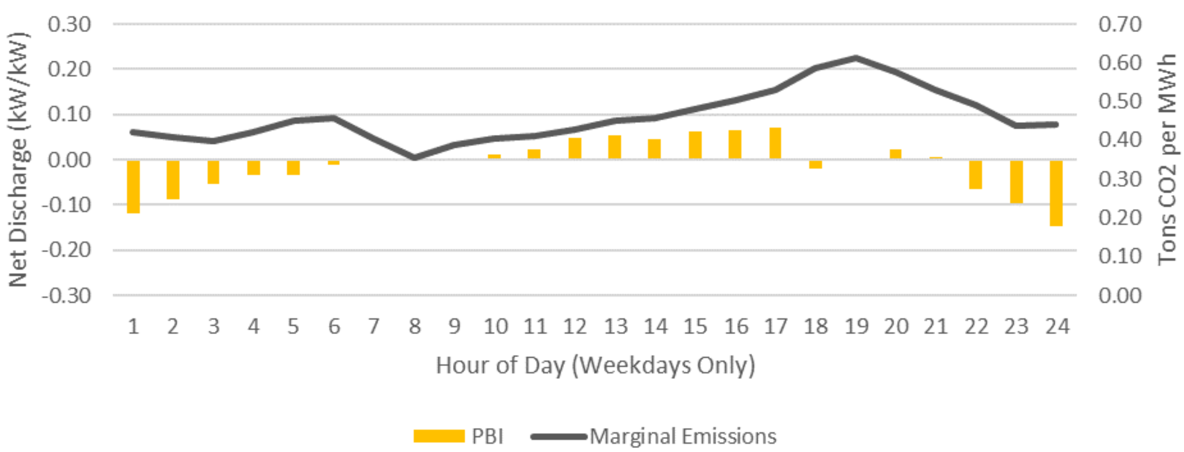


FIGURE 4-68: NON-PBI NET DISCHARGE PER REBATED KW MARGINAL EMISSIONS RATE FOR WINTER

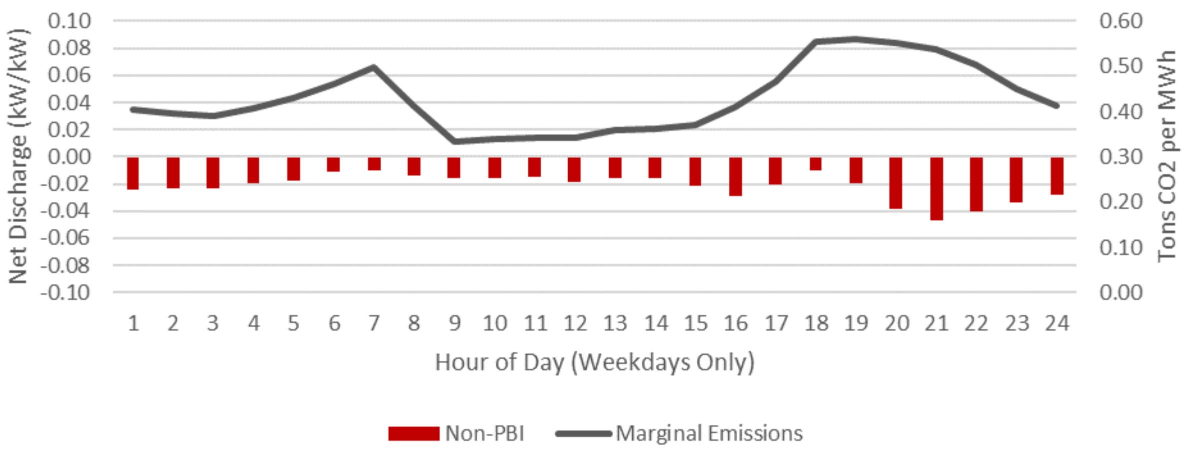
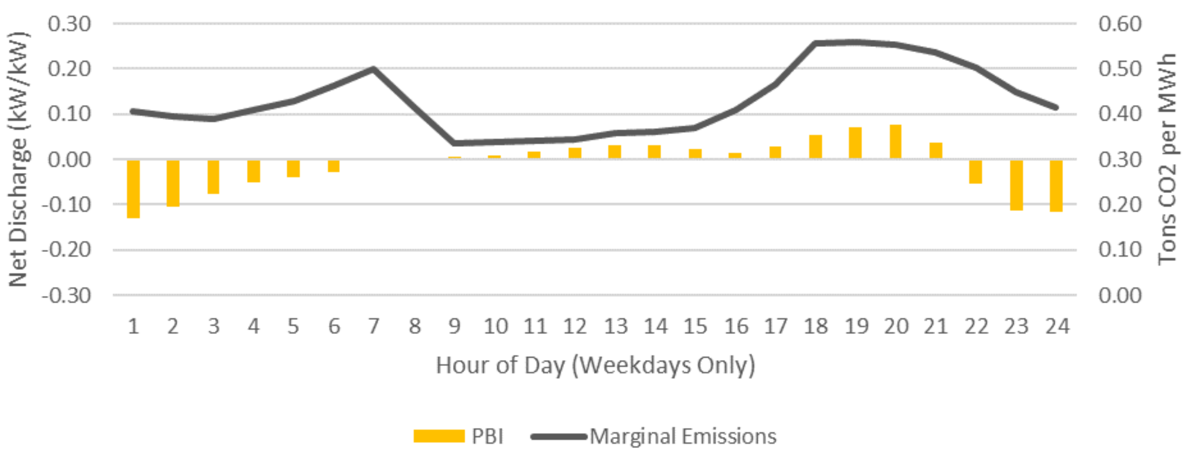
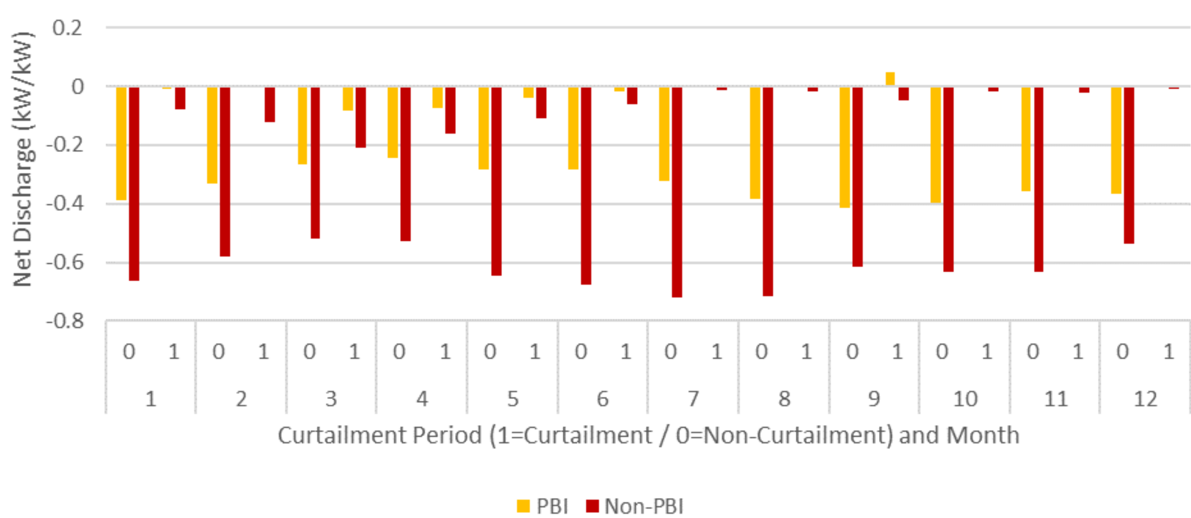


FIGURE 4-69: PBI NET KWH DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR WINTER



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 September, 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 4-70: NET DISCHARGE KW PER KW BY MONTH AND CURTAILMENT EVENTS



4.5.2 Residential Environmental Impacts

All sampled residential projects contributed to an increase in GHG emissions. 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 leads 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.

FIGURE 4-71: NET CO2 EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS

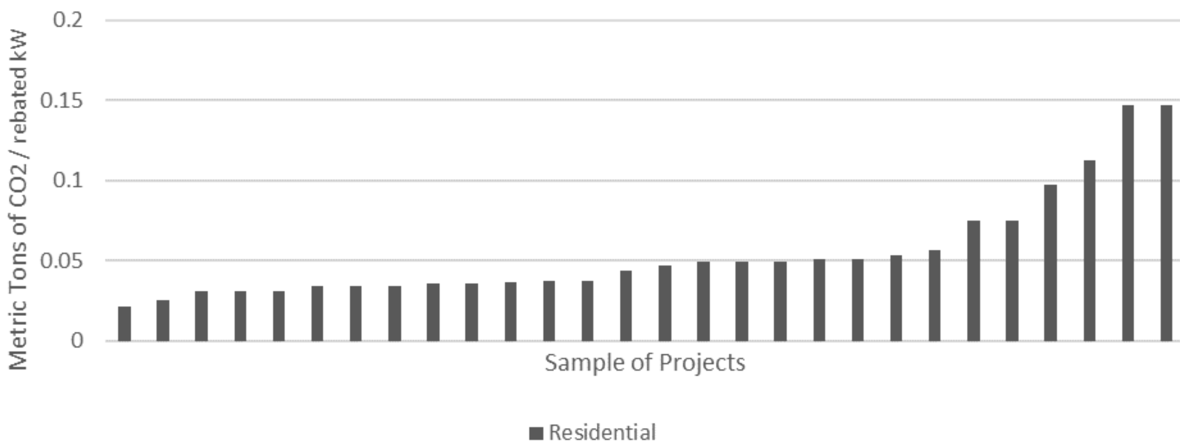


Figure 4-72 through Figure 4-74 summarize the average CO_2, PM_{10} and NOx impacts of residential energy storage systems. The average CO_2, PM_{10} and NOx emission impacts are highly correlated given the underlying assumptions used in development of all three emission profiles. We observed average increases in emissions for all three pollutants.

FIGURE 4-72: AVERAGE CO2 EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS

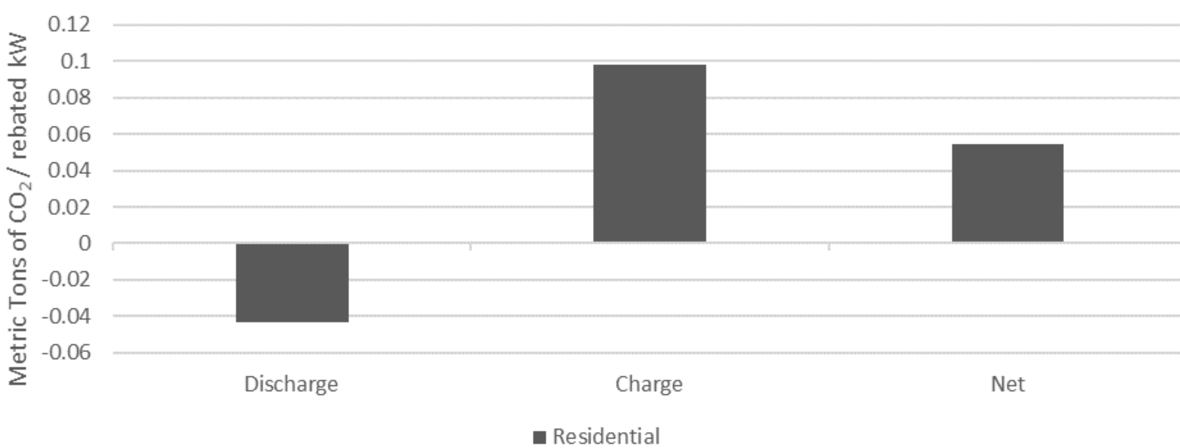


FIGURE 4-73: AVERAGE PM_{10} EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS

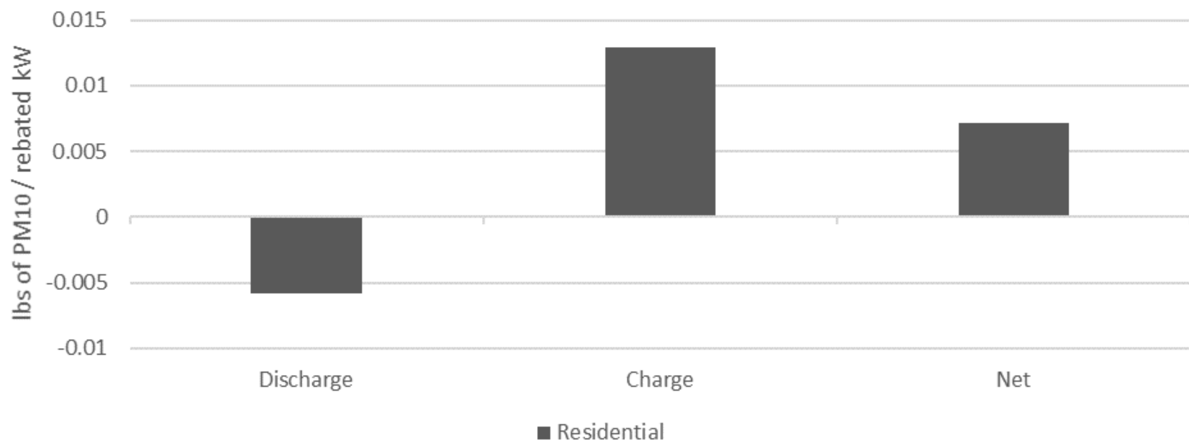
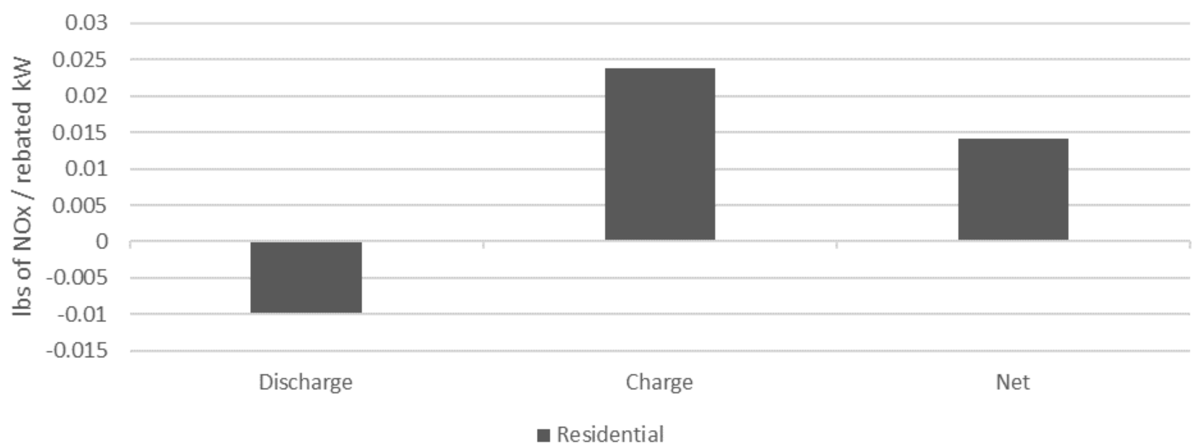


FIGURE 4-74: AVERAGE NOX EMISSIONS PER REBATED CAPACITY FOR RESIDENTIAL PROJECTS



4.6 UTILITY MARGINAL COST IMPACTS

Utility marginal cost impacts were calculated for each IOU and each hourly time increment in 2017. The marginal costs used in our analysis are based on the 2017 values included in the 2018 release of the E3 DER Avoided Cost Calculator.[20] Storage system charging results in an increased load and therefore will

[20] 2018 DER Avoided Cost Calculator and Documentation available at: http://www.cpuc.ca.gov/General.aspx?id=5267

generally increase cost to the system and discharging generally results in a benefit, or avoided cost, to the system.

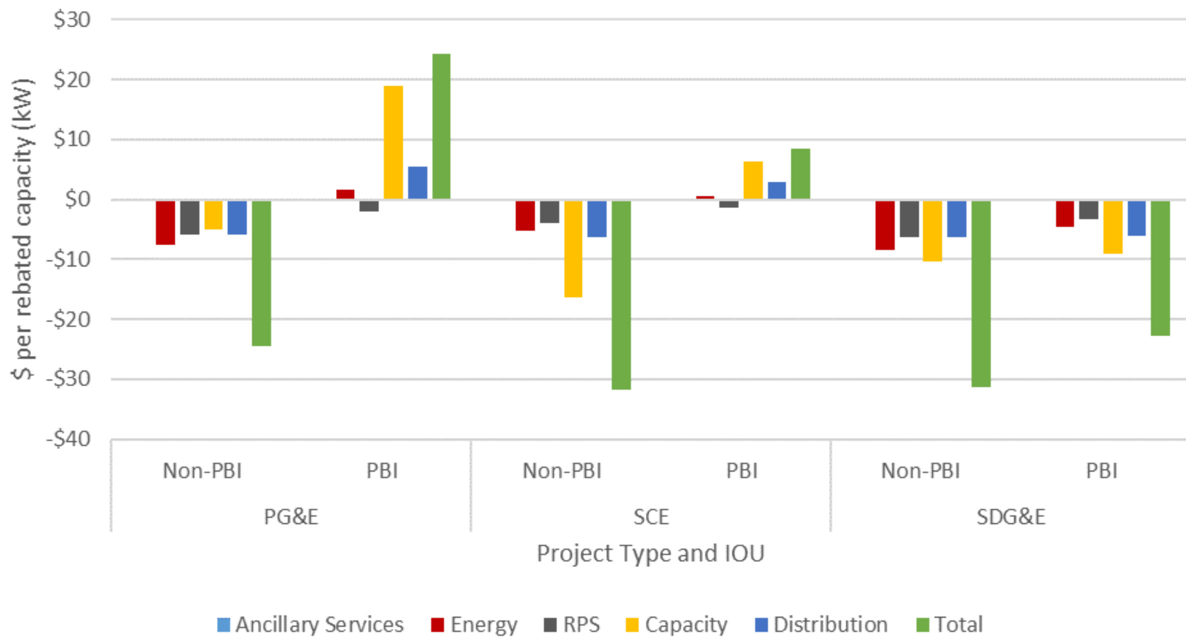
For AES projects to provide a benefit to the grid, the marginal costs “avoided” during storage discharge must be greater than the marginal cost increase during storage charging. Since AES technologies inherently consume more energy during charging relative to energy discharged, the marginal cost rate 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[21] (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.

4.6.1 Nonresidential Utility Cost Impacts

The normalized utility marginal costs are shown in Figure 4-75 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 $2.27 per rebated capacity (kW) and the average marginal cost (-) for non-PBI projects is $29.04 per rebated capacity (kW).

[21] Section 5 provides a detailed definition of RPS and all other marginal costs.

FIGURE 4-75: MARGINAL AVOIDED COST $ PER REBATED CAPACITY (KW) BY IOU AND PROJECT TYPE

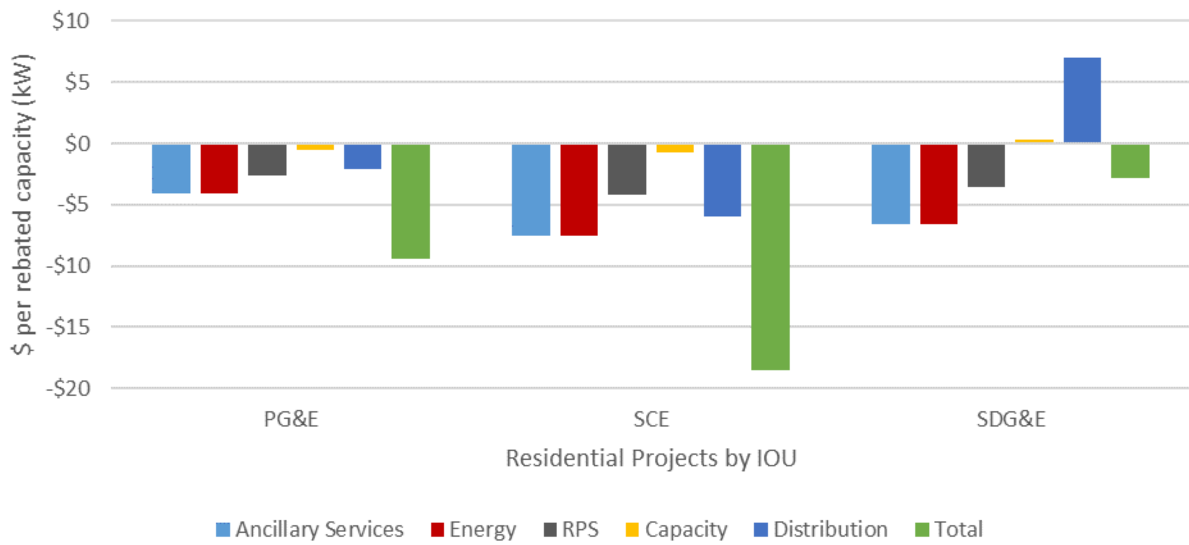


Overall, non-PBI projects represent a net cost to the utility system. The marginal costs modeled in this study are highest when energy prices are high and the CAISO system load is peaking. Section 4.3 provided evidence that non-PBI projects are net charging, on average, throughout the year. In other words, these projects are charging during both low and high marginal cost periods. Section 4.4 also provided evidence that non-PBI projects were charging during CAISO peak hours which represents a net capacity cost. PBI projects, conversely, are providing a net marginal benefit for two utilities (Figure 4-75). These projects were generally discharging during periods when energy prices were high and charging overnight, when marginal prices were lower. The benefits generated during the discharge periods are greater than the cost incurred during storage charge. Likewise, PBI systems were generally discharging during peak CAISO hours. This provides a significant capacity benefit.

4.6.2 Residential Utility Cost Impacts

The normalized utility marginal costs are shown in Figure 4-76 for residential projects by electric IOU. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). The average marginal cost (-) for residential projects is $10.86 per rebated capacity (kW).

FIGURE 4-76: MARGINAL COST $ PER REBATED CAPACITY (KW) BY IOU (RESIDENTIAL PROJECTS)



4.7 DISTRIBUTION SYSTEM IMPACTS

SGIP energy storage systems can provide distribution system benefits by discharging during the top hours of a feeder's annual load. By using energy storage to reduce peak load on a distribution feeder, it is possible to defer costly investments required to accommodate load growth on the feeder. Energy storage systems can also provide benefits by charging during excess PV generation hours which can cause reverse power flow up to the substation transformer and create potential issues related to protection.

This SGIP energy storage evaluation assessed the impact of distributed behind-the-meter storage on distribution feeders. We collected feeder Amperage data from 81 feeders located in two distinct IOU service territories. The sample of feeders represents a diversity of load sizes, climate zones, customer classes (e.g., commercial, residential, industrial) and other demographic information (e.g., urban, rural). We identified which SGIP energy storage systems are served by these feeders and matched their charge/discharge data to the feeder load profiles. There is also variability in the sizes of energy storage systems served by these feeders, ranging from 9 kW to 2.4 MW in rebated capacity.

We received Amperage data for each of the three phases on the distribution feeders. For simplicity, we took the maximum Amp values at 15-minute intervals and averaged them across three phases (we did not have detailed feeder network models assigning each energy storage system to a specific phase). We then compared the timing of charge/discharge to the top hour of feeder load, and the top 200 hours where both charge/discharge and Amperage data were available. Note that this analysis is not meant to be representative of all California IOU distribution feeder types. Instead, this is meant to be an initial exploration into the relative timing of storage charge/discharge relative to feeder peak hours.

Our final distribution feeder analysis dataset consisted of 89 energy storage systems, representing 18.4 MW of rebated capacity, served by 81 distinct distribution feeders located across two IOU service territories. As expected, we observed significant variability between customer loads and feeder load shapes. In some cases, a customer's load profile was very representative of the feeder load shape. This might be the case when all customers on a feeder are the same class (e.g., small commercial) and loads are largely driven by air conditioning. We also saw cases where a feeder load might be dominated by a large industrial customer, and a small commercial customer with storage and solar PV would have a load shape that is not at all aligned with the feeder load shape.

These differences in load shapes led to significant variability in storage behavior during feeder top hours. On average, SGIP energy storage systems were charging 0.0085 kW per rebated capacity during the top hours of their local distribution feeders. The top hour impact ranged from 0.204 kW per rebated capacity charging to 0.094 kW per rebated capacity discharging across 81 distinct feeders.

In addition to analyzing the impacts of the top hour for each feeder, we compared the top 200 hours for each feeder. The impact during these top 200 hours ranged from 0.030 kW per rebated capacity charging to 0.038 kW per rebated capacity discharging across 68 distinct feeders. Note that not all feeders had charge/discharge data during the top 200 hours. On average, the 75 SGIP energy storage systems across the 68 feeders were charging 0.0013 kW per rebated capacity during the top 200 hours of each feeder.

Distribution system upgrade deferral is one of the many value streams that SGIP energy storage can deliver. By charging and discharging during the right hours, energy storage systems can reduce the maximum demand on a distribution feeder and defer an investment for several years. However, utilities require confidence that these load reductions will occur before choosing to defer their planned investments. The observed variability in distribution feeder peak hour impacts is expected considering that utilities are not currently targeting customers for this value stream. Distribution system upgrade deferral from SGIP energy storage systems will require careful planning and targeted deployment to specific customers whose load profiles are aligned with the distribution system peak hours. This way, peak demand reduction for the customer would naturally coincide with distribution feeder benefits. Alternatively, the IOUs could develop dynamic tariffs that account for local distribution system conditions.

4.8 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.[22] 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 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 2017. Below we provide a brief description of the types of DR programs SGIP storage customers participated in during 2017.

- Critical Peak Pricing (CPP) and Peak Day Pricing (PDP)
  - CPP is an energy rate adder applied to a customer's tariff for SDG&E and SCE customers. PDP is the same rate, but for PG&E customers
  - Each are day-ahead TOU rate structured programs where customers are charged higher energy rates during event periods
  - During events, participants on the CPP/PDP rate structure are encouraged to reduce/shift load to non-peak hours to avoid high energy costs during the event. However, there is no required level of kW curtailment
  - Events are called based on either: CAISO alert/warning, forecasts of system emergencies (generation, transition or distribution level), forecasts of extreme temperatures and day-ahead load and/or price forecasts
- Capacity Bidding Program (CBP)
  - CBP is a statewide aggregator-managed program with day-ahead and day-of options offered by all three IOUs
  - Aggregators receive monthly capacity payments based on nominated load, in addition to energy payments based on kWh reductions during events. Penalties are instituted if aggregators fail to deliver on their committed load reductions

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

- Events are triggered by either IOU or CAISO market awards and can be called in 1-4, 2-6 or 4-8-hour increments between 11 a.m. to 7 p.m. on non-holiday weekdays
- Up to 30 event hours a month can be called for PG&E and SCE participants and 44 hours a month for SDG&E

- Demand Response Auction Mechanism (DRAM)
  - DRAM is a demand response bid auction that allows participants to bid directly into the day-ahead CAISO energy market
  - IOUs acquire the capacity, but have no claim to any revenues from the winning bidders in the energy market
- PG&E Supply-Side Pilot (SSP)
  - SSP is an aggregator pilot demand response program within the PG&E service territory that allows for demand response to participate in the CAISO wholesale market as a proxy demand resource
- PG&E Excess Supply Pilot (XSP)
  - XSP is an aggregator pilot demand response program that works to integrate grid resources (renewables, electric vehicles, storage and demand response) by shifting energy usage to when there is an excess supply of energy on the grid
  - Participants elect 4-hour blocks of availability and receive day-ahead notice of XSP events
- SDG&E Demand Response Pilot (SDGE Pilot)

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 design and implementation of these programs differs across programs and IOUs. For example, PG&E called 15 PDP events in 2017. Each of those events lasted 4 hours – for a total of 60 hours – and coincide with the TOU peak rate period. Some other DR events are called at the sub-hourly level, however, so the total number of hours awarded can be less than the total number of days when events are called.

Overall, SGIP projects participating in DR programs are responding by discharging throughout event periods and, by extension, reducing energy consumption behind-the-meter. The exception to this is the project enrolled in the XSP program which is designed to absorb load (i.e., charge) during periods of over-generation.

Systems that were discharging throughout the respective DR event hours also decreased GHG emissions and provided a net utility cost benefit. The magnitude of GHG reductions and avoided costs are predicated on several factors, including the number of event calls, the duration of those events, the number of projects participating and the size of the storage system behind-the-meter. DR programs like CBP participate in the day-ahead CAISO market and are triggered during periods of high system-level stress. These events generally coincide with periods of high marginal utility costs, especially during hours that are generation capacity and/or distribution capacity constrained.

While it is intuitive that storage projects will produce GHG emission reductions and utility marginal cost savings when discharging throughout DR event periods, these systems will ultimately have to charge again throughout the day. Again, since AES technologies inherently consume more energy during charging relative to energy discharged, the marginal emissions rate or utility marginal cost rate must be lower during charging hours relative to discharge hours to realize benefits.

The evaluation team conducted an analysis of each project participating in their respective DR program by comparing the performance of the system during DR event days to non-event days. We analyzed the storage utilization, GHG emissions and utility marginal costs (by project) for each day of each week[23] when at least one DR event was called. We then developed an average capacity factor for each of those days and determined the percentage of total days across all projects where there was a reduction in GHG emissions and utility marginal costs. Table 4-1 conveys the results of that analysis.

For most programs, there is very little variation in storage utilization from days where DR events were called compared to non-event days. The more significant difference is in the number of days with GHG emission and utility marginal cost reductions, especially for programs like CBP, SSP, XSP, and CPP in SDG&E territory. The projects participating in CBP reduced GHG emissions on 37% of the event days compared to 20% of non-event days. SSP projects exhibit a similar pattern (48% of event days and 27% of non-event days).

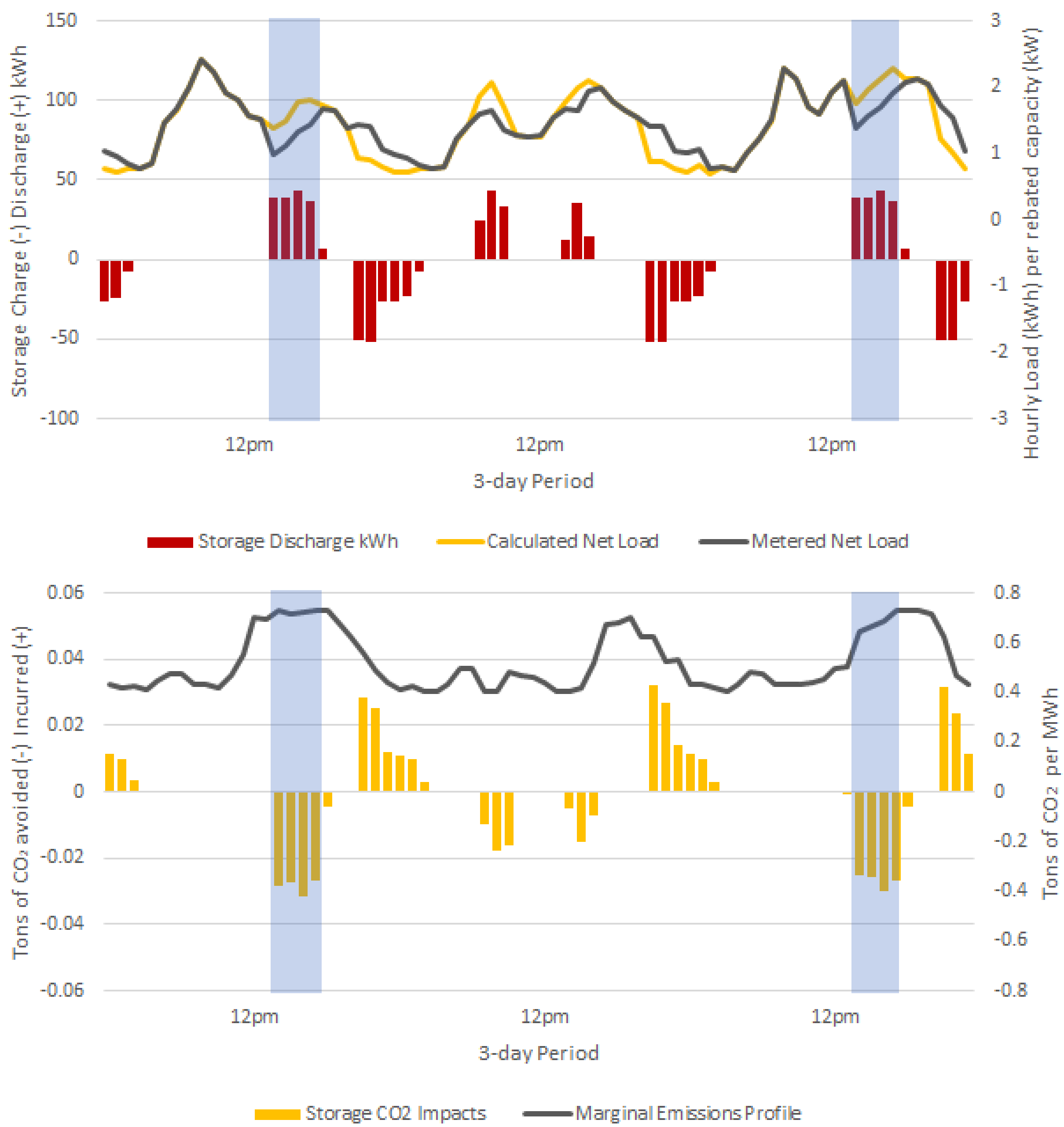
[23] This analysis was conducted for only Monday-Friday and excluded weekends.

TABLE 4-1: SUMMARY OF SGIP AES IMPACTS DURING EVENT DAYS COMPARED TO NON-EVENT DAYS (BY IOU)

Utility	Program	Event Flag (0=No, 1=Yes)	Total Project Days	Average Capacity Factor (per day)	% Days with GHG Reduction	% of Days with Utility Avoided Cost
PG&E	CBP	0	272	0.05	20%	25%
		1	155	0.06	37%	45%
	DRAM	0	123	0.03	3%	10%
		1	37	0.05	0%	11%
	PDP	0	96	0.05	0%	0%
		1	84	0.07	0%	4%
	SSP	0	268	0.02	27%	28%
		1	287	0.03	48%	65%
	XSP	0	188	0.09	5%	1%
		1	72	0.14	28%	50%
SCE	CPP	0	159	0.03	19%	23%
		1	82	0.04	21%	27%
	DBP	0	20	0.04	25%	30%
		1	20	0.04	30%	30%
	DRAM	0	100	0.05	2%	2%
		1	25	0.05	4%	16%
SDG&E	CPP	0	75	0.04	4%	17%
		1	50	0.05	14%	28%
	DRAM	0	1,689	0.05	0%	1%
		1	766	0.06	1%	3%
	SDGE Pilot	0	324	0.03	24%	20%
		1	152	0.05	9%	5%

To illustrate the importance of storage dispatch timing as it relates to GHG emissions and customer bill impacts, we present a representative storage profile of a project participating in a DR program. In this example, a 4-hour DR event is called on both the first and third 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 160 kWh throughout each of the DR event periods in the example, remains idle for a few hours and charges later in the evening. 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 remains idle throughout the remaining hours of high marginal emissions and only charges thereafter – during a period of lower emissions. In this example, the storage system will have reduced GHG emissions on both event days. On the non-event day, however, the storage system would contribute a net increase in emissions. Without the DR signal, the storage system is programmed to manage facility peak demand and discharges throughout the day to shave those peak loads. The utilization of the battery is identical on all three days. The difference is in the timing of dispatch.

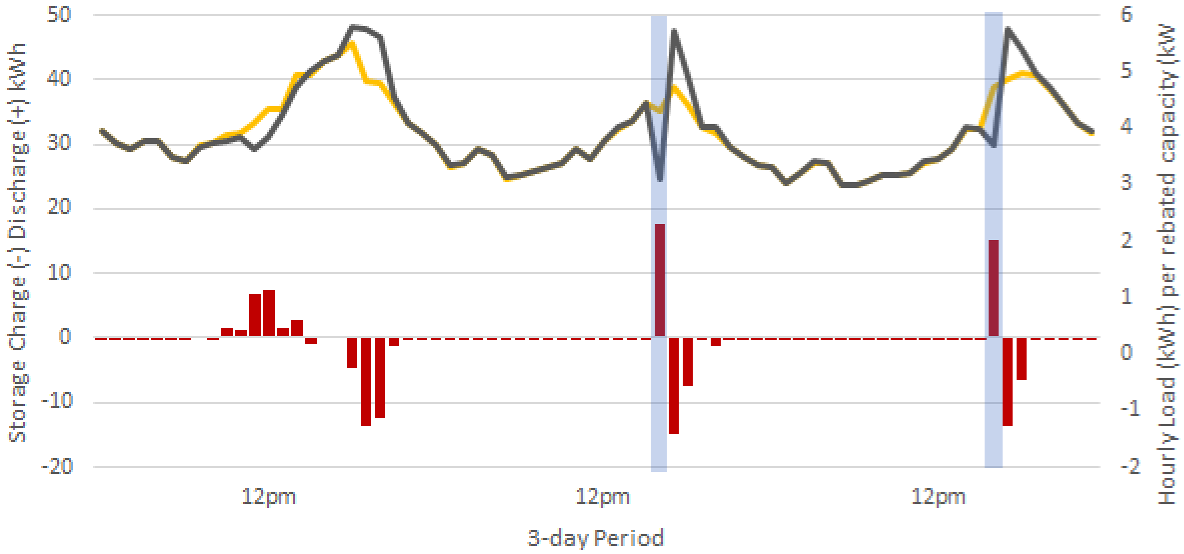
FIGURE 4-77: EXAMPLE OF 4-HOUR DEMAND RESPONSE EVENT WITH STORAGE, LOAD AND GHG PROFILES

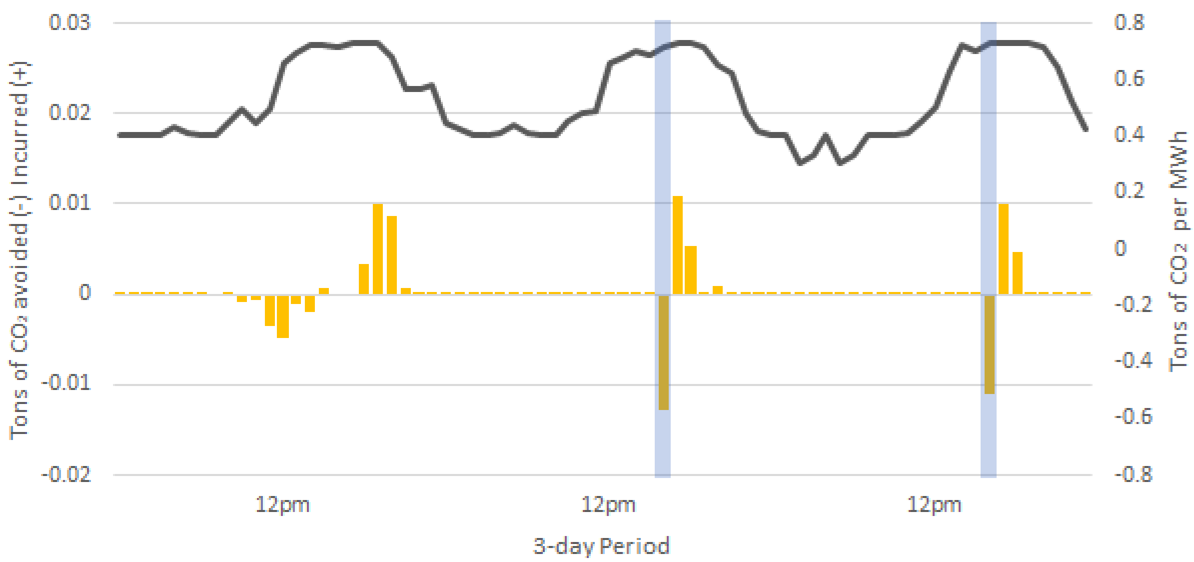


While the above example illustrates that storage systems participating in DR programs can provide GHG emission reductions, these benefits are predicated on a number of factors – the price signal of the DR event in relation to the opportunity cost of potentially missing peak demand reduction for that 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.

Figure 4-78 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 and third day and is maintaining normal dispatch behavior on the first day. On the first day, the system discharges as the mid-day load ramps. However, perhaps due to the size of the storage system relative to the facility load, the system begins charging throughout the latter part of load ramp and, consequently, increases load for that day. On the second and third day, the system ignores the early ramp in anticipation of the DR events being called in the early afternoon. When the events are called, the system discharges a significant percentage of system capacity throughout the hour to satisfy the event call and charges immediately thereafter. This also leads to an increase in load for each of those days. Similarly, the charge and discharge behavior of the system on all 3 days leads to 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. On the two DR event days, if the storage system had discharged as it had done and charged 4 or 5 hours later, it is likely the customer would not have increased load throughout each day and they would have realized a GHG emissions reduction.

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





The evaluation team also conducted a closer examination of the PDP/CPP rate programs. Again, these rates charge higher energy prices during specific event periods triggered by forecasted high temperatures and system load. This program lent itself to this analysis because the events were all called at the same hours throughout the summer (by IOU). This allowed us to compare storage dispatch for customers on a CPP/PDP rate during the event hours themselves as well as those same hours throughout the summer when an event was not called. We also compared the storage dispatch behavior across groups (customers on the CPP/PDP tariff to those not enrolled in it).

During 2017, all three IOUs had CPP/PDP events triggered. For PG&E, 15 events were executed throughout the summer and lasted from 2 pm to 6 pm (PDT). For SCE, 12 events were executed, also lasting from 2 pm to 6 pm. SDG&E called 3 events, which lasted from 11 am to 6 pm.

After reviewing the rate schedules obtained for each of the SGIP storage customers, we confirmed that 39 customers were on a CPP/PDP rate for at least one event throughout the year.[24] There were six customers in PG&E, seven in SCE and 26 in SDG&E. We examined each customer's storage discharge behavior during these event periods to ascertain if the price signals sufficiently influenced dispatch behavior. We compared the average hourly net discharge kW during event hours – 2 pm to 6 pm in PG&E or SCE, for example – to that same time-period during weekdays throughout the summer on days when events were not called. We conducted the same analysis with customers not on a CPP/PDP rate. Figure 4-79 presents those results.

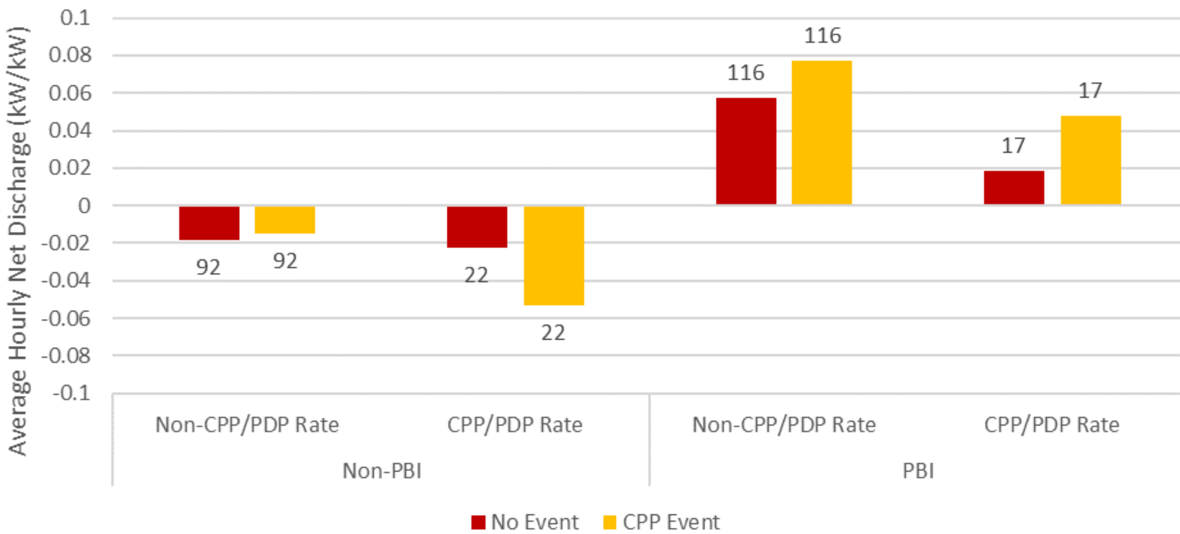
PBI projects on a CPP/PDP rate in 2017 were discharging more (on average) during called event periods compared to those same hours throughout the summer when events were not called. However, this observation holds true for PBI customers not on that rate as well. Non-PBI customers were net charging (on average) throughout all hours regardless if an event had been called or if they were on a CPP/PDP rate. Non-PBI customers on the CPP/PDP rates were charging more (on average) throughout the event hours.

As presented throughout this report, customers are generally utilizing storage to reduce non-coincident peak demand. If a customer's peak facility load occurs prior to the CPP/PDP event, they may have discharged the battery and are coincidentally charging during the event hours (to maintain the system state-of-charge (SOC) and to potentially prepare for more facility peak shaving). These events are called in response to forecasted high temperatures, so facilities with significant cooling loads may be discharging earlier than the prescribed event hours to meet those increased demands. However, while the storage system is charging and increases the consumption behind-the-meter during the event hours, customers may very well be instituting additional behavioral responses at the facility to generate reductions in

24 Some rates default customers onto the CPP rate, but they can opt out.

demand.[25] Other DR events are more punctuated or may occur throughout a time period when storage is not being optimized to deliver on-bill savings.

FIGURE 4-79: AVERAGE HOURLY NET DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR CPP/PDP RATES



4.9 STORAGE CO-LOCATED WITH PV

One potential benefit of energy storage paired with solar PV is the ability to charge the system from PV and discharge in the afternoon during peak hours. This could mitigate local distribution feeder issues with reverse power flow and steep afternoon ramp rates, while also providing benefits to the system overall. We find evidence of both residential and nonresidential systems being co-located with PV. However, note that co-location of PV does not imply that the systems are in some way paired and working together.

Most residential energy storage systems in the SGIP population are paired with PV. All residential projects in our sample were paired with PV. Figure 4-80 and Figure 4-81 show average solar PV generation and storage charge/discharge profiles in July and November, respectively. Figure 4-80 shows mostly discharge during PV generation hours, and charge beginning while PV is ramping down into the evening. This behavior would tend to aggravate local distribution system issues by further lowering load during mid-

[25] These rates are designed to reduce overall demand at a home or facility throughout targeted perceived hours of capacity and distribution constraints. Storage dispatch is one way to accommodate those reductions. Others include behavioral changes like increasing the set point on thermostats, turning off lights, reducing plug loads, running an icemaker prior to the event or utilizing eligible on-site generation technologies.

day and increasing demand in the early evening when residential customers typically see their peak demand.

FIGURE 4-80: AVERAGE DAILY NET DISCHARGE AND PV GENERATION FOR RESIDENTIAL PROJECTS (JULY)

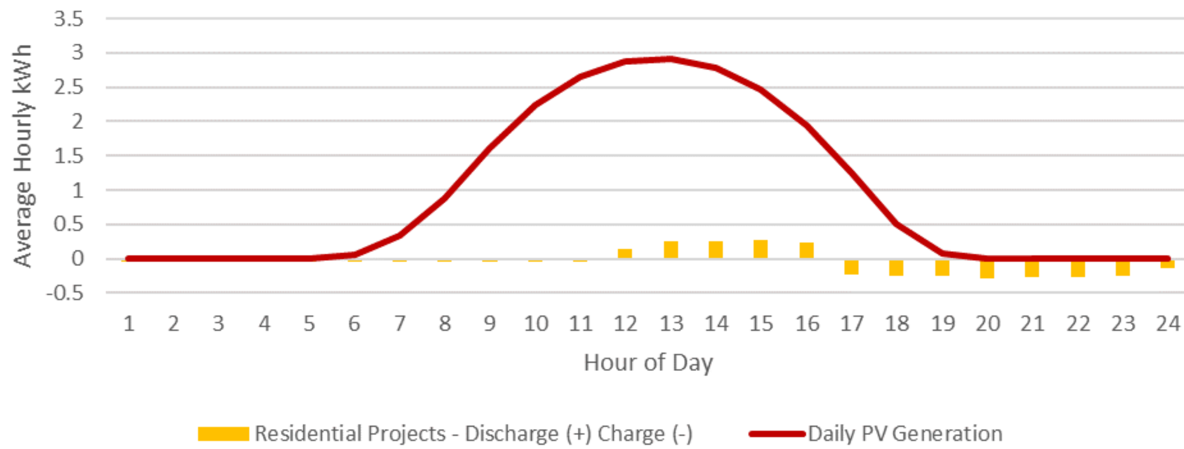
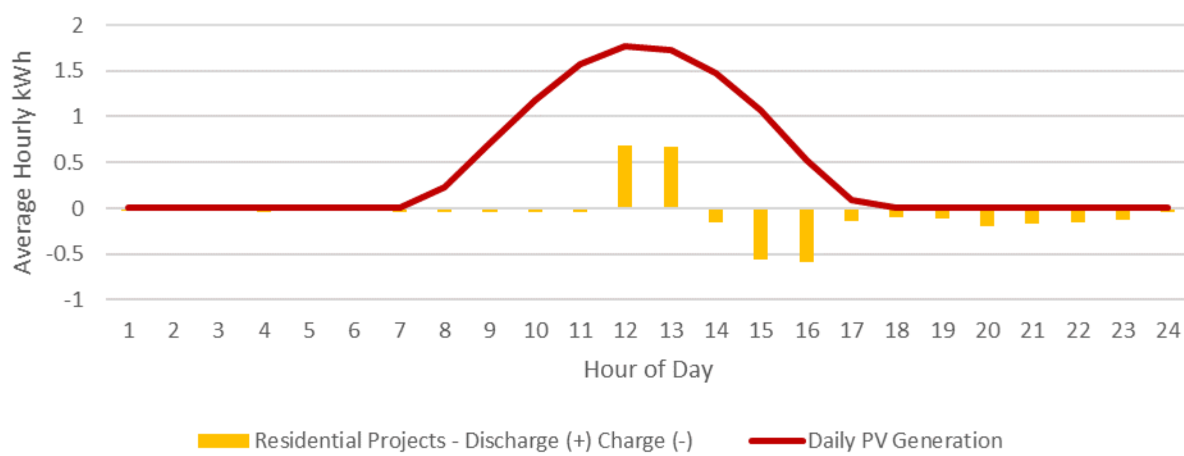


Figure 4-81 shows similar behavior – the main difference being that residential projects in our sample began to actively cycle for program compliance later in the year. Again, we see significant discharge around noon, followed by charging shortly after when PV is ramping down. The same pattern of continuous charging continues into the late evening.

FIGURE 4-81: AVERAGE DAILY NET DISCHARGE AND PV GENERATION FOR RESIDENTIAL PROJECTS (NOVEMBER)



4.10 POPULATION IMPACTS

Metered data available for the sample of projects were used to estimate population total impacts for 2017. Relative precision levels reported in the tables are based on a confidence level of 90%. Population estimates were calculated for the following 2017 impacts:

- Customer average summer-time peak demand
- CAISO system peak demand (top hour and top 200 hours)
- Electric energy
- Environmental Impacts

Customer peak demand impacts during summer months provide some indication of the way nonresidential customers are utilizing their AES systems to manage loads and reduce electricity costs. Summarizing these impacts of SGIP AES systems is complicated by the fact that projects are coming online periodically throughout the year, and tariff definitions of 'summer' vary. Consequently, a simplified measure of average monthly population total customer peak demand impacts was calculated. For each customer, the impact of AES on billed demand for each of four summer months (June through September) was calculated as the difference between observed maximum 15-minute net load and an estimate of the load that would have been observed without the AES. Results calculated for each of those four summer months were averaged for each sampled participant. Finally, estimated impacts for the entire population were approximated based on the total number of complete projects at the end of July. Summer-time average customer peak demand impacts are summarized in Table 4-2. PBI and non-PBI nonresidential projects produced reductions in summertime average customer peak demand. Residential projects increased peak demand slightly. We achieved our relative precision targets for the nonresidential sector as well as the program overall.

TABLE 4-2: POPULATION TOTAL SUMMER-TIME AVERAGE CUSTOMER PEAK DEMAND IMPACTS

Customer Sector	N	Population Impact (kW)	Relative Precision
Nonresidential PBI	138	-1,918	3%
Nonresidential Non-PBI	275	-496	8%
Residential	400	28	18%
Total	**813**	**-2,386**	**3%**

CAISO system peak demand impacts are summarized in Table 4-3 (top hour). In 2017 the CAISO statewide system load peaked at 49,909 MW on September 1 during the hour from 3 to 4 PM PST. While PBI projects delivered CAISO system peak demand reduction exceeding 4 MW, non-PBI nonresidential projects were net consumers of electricity during this hour. On average, the non-PBI projects were charging during the hour of the CAISO system peak whereas the PBI AES projects were discharging. 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 Impact (kW)	Relative Precision
Nonresidential PBI	139	-4,002	13%
Nonresidential Non-PBI	278	420	49%
Residential	405	-53	141%
Total	**822**	**-3,635**	**15%**

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

Customer Sector	N	Population Impact (kW)	Relative Precision
Nonresidential PBI	139	-2,942	9%
Nonresidential Non-PBI	278	200	13%
Residential	405	14	79%
Total	**822**	**-2,728**	**9%**

Electric energy impacts (i.e., the total energy impact that resulted from charging and discharging AES projects) during 2017 are summarized in Table 4-5. Electric energy impacts for both PBI and non-PBI are positive, reflecting increased energy consumption, as expected. These impacts are for 2017; many projects were operating during the entirety of 2017, but others entered service mid-way through 2017. This summary result reflects the combined effects of several factors, including timing of charging and discharging, standby loss rates and utilization levels and roundtrip efficiency. The total energy impact was an increase in electric energy consumption of 5,579 MWh during 2017.

TABLE 4-5: ELECTRIC ENERGY IMPACTS

Customer Sector	N	Population Impact (MWh)	Relative Precision
Nonresidential PBI	143	4,339	2%
Nonresidential Non-PBI	278	1,041	10%
Residential	407	198	8%
Total	**828**	**5,579**	**3%**

Greenhouse gas impacts during 2017 are summarized in Table 4-6. Greenhouse gas impacts for both PBI and non-PBI 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. While the timing of AES charging and discharging produced valuable reductions in summer-time customer peak demand, one consequence of that timing was an increase in greenhouse gas emissions. We observe similar results for NOx and PM_{10} impacts, as shown in Table 4-7 and Table 4-8.

TABLE 4-6: GREENHOUSE GAS IMPACTS

Customer Sector	N	Population Impact (MT CO_2)	Relative Precision
Nonresidential PBI	143	974	4%
Nonresidential Non-PBI	278	462	9%
Residential	407	116	18%
Total	**828**	**1,552**	**4%**

TABLE 4-7: NO_X IMPACTS

Customer Sector	N	Population Impact (lbs NO_x)	Relative Precision
Nonresidential PBI	143	6	279%
Nonresidential Non-PBI	278	108	9%
Residential	407	30	20%
Total	**828**	**144**	**15%**

TABLE 4-8: PM_{10} IMPACTS

Customer Sector	N	Population Impact (lbs PM_{10})	Relative Precision
Nonresidential PBI	143	157	3%
Nonresidential Non-PBI	278	61	9%
Residential	407	15	18%
Total	**828**	**234**	**3%**

Utility marginal cost impacts during 2017 are summarized in Table 4-9. Utility marginal costs are negative for PBI projects (costs were avoided) and positive for non-PBI residential and nonresidential projects (costs were incurred).

TABLE 4-9: UTILITY MARGINAL COST IMPACTS

Customer Sector	N	Population Impact (Avoided Cost $)	Relative Precision
Nonresidential PBI	143	-$646,693	10%
Nonresidential Non-PBI	278	$144,719	17%
Residential	407	$22,972	28%
Total	**828**	**-$479,002**	**14%**

5 IDEAL DISPATCH OF SGIP AES PROJECTS IN 2017

This chapter describes analysis performed to quantify the *maximum* benefits SGIP storage projects could have potentially achieved in 2017, *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 marginal carbon dioxide emissions for the associated customer

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 2017 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, 2017. 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 2017 if they ideally responded to different signals based on perfect information.

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

With the exception of Section 5.3.6, this chapter covers only *nonresidential* storage dispatch and is based solely on nonresidential data, which makes up 97% of total SGIP storage rebated capacity.

The evaluation team received gross and net load shapes, battery sizes and tariff information for 287 nonresidential SGIP customers. Of those 287 projects, 39 were offline or had been decommissioned in 2017, and were therefore removed from the sample. E3's model requires complete tariff information and a load shape free of gaps in order to accurately produce optimized dispatch. We therefore removed an additional 14 projects due to conflicting tariff information or large amounts of missing load data. Of the 234 AES projects remaining in the sample, 192 had 15-minute load profiles with at least one missing value and 53 profiles had data gaps that exceeded one hour in duration. We filled these gaps to create complete profiles for use in RESTORE. The evaluation team filled gaps that spanned one hour or less by linear interpolation between the two data points either side of the gap. Gaps that spanned more than one hour were filled using an average of the data points in the corresponding 15-minute time interval three days either side and three weeks either side of the missing data point. In instances where the project came online midway through the year, the project was not modeled until it came online.

Based on review of SGIP Inspection Reports, the evaluation team has elected to use SGIP rebated capacity with a duration of two hours for this storage dispatch exercise. Thus, figures reported below reflect the program-defined SGIP rebated capacities of the batteries, with kWh available equal to twice the kW value.

As our analysis was conducted using a sample of nonresidential AES projects rather than the entire population, the results had to be scaled up to estimate population-level impacts. To scale results from our sample to the nonresidential SGIP AES population, we first determined the 'effective' annual kW of storage in our sample. Since some storage systems came online midway through 2017, it would be inaccurate to simply sum the total capacity in our sample. Instead, we calculated a discounted, 'effective kW' value for each project by multiplying the project's kW by the percentage of 2017 that the AES project was online. The same treatment was applied to the population kW. Then, each project's individual impacts ($ or tons) were divided by the project's effective kW, and the results were summed over all projects to produce total sample impacts per effective kW. Population effective kW were then determined by taking the full nonresidential SGIP AES population value and subtracting out the total kW in our sample that were shown to be offline or decommissioned for the entirety of 2017. The total sample impacts per effective kW was multiplied by the population effective kW to yield estimated total population impacts. Table 5-1 summarizes the sample size used for simulations relative to the population.

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

	Nonresidential AES Sample	Nonresidential AES Population
Number of Modeled Projects	234	382
kW of Rebated Capacity Associated with Modeled Projects	48,678	61,856
kW of Effective Capacity Associated with Modeled Projects	48,648	61,818

5.2 SIMULATING IDEAL STORAGE DISPATCH: METHODOLOGY

The first approach we used to quantify the maximum potential value of SGIP AES in 2017 was to optimize AES dispatch using E3's RESTORE model. E3's RESTORE model 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".[2] 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.[3] A public version of the full model is planned for release in March 2019.

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

The evaluation team also developed an hourly kWh estimate of parasitic charge for each storage project. These values were relatively small, ranging from 0.4% to 13.3% of rebated capacity on average across the year, depending on the project, with a median of 2.6%. These parasitic charges decrease the annual roundtrip efficiency of each project slightly. This parasitic charge data was included in our RESTORE

2 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

3 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

modeling as a constant, average contribution to the state of charge for each project. All results in this chapter therefore account for parasitic charges.

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 2017. We obtained rate information from the IOUs' tariff sheets. We did not include demand response revenue to the customer in these results, though we did perform a sensitivity that covered these programs (Section 5.3.3).

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 and 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 2017. The marginal costs used in our analysis are based on the 2017 values included in the 2018 release of the E3 DER Avoided Cost Calculator.[4] 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 ($/kWh)	CAISO OASIS Day-Ahead location-based marginal prices, NP-15 and SP-15[5]
Losses	E3 Avoided Cost Calculator, by IOU
System Capacity ($/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)

4 2018 DER Avoided Cost Calculator and Documentation available at: http://www.cpuc.ca.gov/General.aspx?id=5267

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

Consistent with previous avoided cost analyses performed by E3, the marginal cost of energy generation is based on the locational marginal prices of the trading hub nearest to the AES project (NP15 for PG&E; SP15 for SCE and SDG&E). The 2017 $/kW-year marginal cost of generation capacity is taken from the 2018 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	2017 Marginal $/kW-year of Generation Capacity
PG&E	$130.79
SCE	$127.95
SDG&E	$127.53

The marginal capacity cost is allocated across the 15-minute time intervals of the year using a peak capacity allocation factor (PCAF) method.[6] 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 2017 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.

6 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	2017 Marginal $/kW-year of Transmission Capacity
PG&E Zone CZ1	$37.84
PG&E Zone CZ2	$39.61
PG&E Zone CZ3A	$38.72
PG&E Zone CZ3B	$42.98
PG&E Zone CZ4	$39.28
PG&E Zone CZ5	$37.17
PG&E Zone CZ11	$40.26
PG&E Zone CZ12	$36.08
PG&E Zone CZ13	$39.56
PG&E Zone CZ16	$37.96
SCE	$39.19
SDG&E	$0

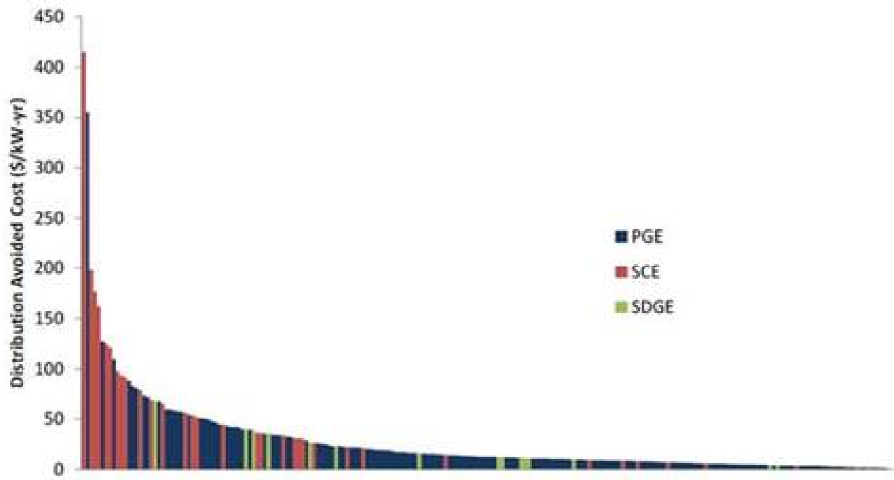
We use marginal distribution costs from the 2018 Avoided Cost Calculator, which are calculated from IOU general rate case filings. The $/kW-Yr. distribution costs in the Avoided Cost Calculator represent the load growth related transmission and distribution capital investments that could be deferred with distributed energy resources that reduce peak loads.

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

IOU	Assumed 2017 $/kW-year of Distribution Capacity
PG&E Zone CZ1	$102.60
PG&E Zone CZ2	$70.69
PG&E Zone CZ3A	$92.47
PG&E Zone CZ3B	$73.68
PG&E Zone CZ4	$132.84
PG&E Zone CZ5	$96.20
PG&E Zone CZ11	$91.02
PG&E Zone CZ12	$102.30
PG&E Zone CZ13	$91.36
PG&E Zone CZ16	$99.00
SCE	$106.87
SDG&E	$106.71

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 5-1 shows marginal distribution costs by planning area for the three IOUs from 2012. A limited number of locations have a high value above $100/kW-Yr., whereas most locations have a value below $50/kW-Yr.

FIGURE 5-1: MARGINAL DISTRIBUTION COSTS BY PLANNING AREA[7]



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

Our $/MWh marginal RPS costs are based on the $/MWh renewable premium prices found in the Avoided Cost Calculator. These are shown in Table 5-6. In California, the RPS is a minimum percentage of delivered energy that must come from a renewable resource. When additional load is incurred, if this load is served with non-renewable resource energy, this increases the amount of renewable energy that a utility must procure. For example, under a 50% RPS, a MWh of incremental load met with a conventional resource results in an additional MWh of renewable energy that must be procured and delivered to meet 50% compliance. The marginal RPS cost reflects the cost of procuring and delivering additional renewable energy, per MWh of incremental load.

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

TABLE 5-6: $/MWH MARGINAL RPS COST

IOU	Assumed 2017 $/MWh Marginal RPS Cost
PG&E	$12.40
SCE	$12.80
SDG&E	$12.80

Carbon Dispatch

For the Carbon Dispatch, storage is dispatched to reduce carbon dioxide emissions. This is achieved by optimally dispatching storage against a marginal carbon dioxide emissions rate. As described previously, the CPUC has issued a decision that the SGIP program shall be evaluated using 2017 avoided costs calculated using the most recently CPUC adopted avoided cost calculator.[8] E3 therefore 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.[9] 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):

$$\text{HeatRate}[h] = (\text{MP}[h] - \text{VOM}) / (\text{GasPrice} + \text{EF} * \text{CO}_2\text{Cost})$$

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. 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. For our base case analysis, we created these bounds using the Avoided Cost Calculator. These are shown in Table 5-7.

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

9 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.

TABLE 5-7: 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	6,900

In addition to this base case methodology, E3 also ran a sensitivity that bounded heat rates using data compiled from the U.S. EPA's latest eGRID data for California. For this sensitivity, we used the 15th and 85th percentiles of gas plant heat rates from this source as emission rate bounds. These are shown in Table 5-8.

TABLE 5-8: BOUNDS ON ELECTRIC SECTOR CARBON EMISSIONS USING EGRID DATA

Baseline	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	12,503	5,641

Additional details on the marginal emissions dataset used for this analysis are included in Appendix A.

5.3 SIMULATING OPTIMAL 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.

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, aggregated across the 234 projects in our nonresidential sample. Green hours indicate that the sample of AES projects was simulated to be, in aggregate, net discharging; 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 2017, the AES projects in our sample would have dispatched as shown in Figure 5-2. 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 diffuse dispatch across hours suggests that individual customers optimizing their dispatch in 2017 with perfect information would have discharged to reduce their demand charges given their diverse individual load profiles.

FIGURE 5-2: OPTIMIZED NET DISCHARGE (CHARGE), AGGREGATED KW ACROSS SAMPLE (N=234) – CUSTOMER BILL DISPATCH

Hour Beginning	Month 1	2	3	4	5	6	7	8	9	10	11	12
0	(27)	(20)	(16)	(22)	(45)	(60)	(58)	(52)	(54)	(54)	(22)	(26)
1	(36)	(29)	(25)	(38)	(60)	(89)	(81)	(76)	(78)	(71)	(31)	(36)
2	(51)	(43)	(39)	(53)	(79)	(122)	(98)	(109)	(102)	(92)	(43)	(48)
3	(69)	(56)	(58)	(64)	(101)	(151)	(128)	(151)	(150)	(112)	(62)	(61)
4	(87)	(75)	(82)	(71)	(142)	(211)	(192)	(205)	(213)	(159)	(73)	(84)
5	(92)	(86)	(57)	(56)	(156)	(256)	(262)	(291)	(246)	(125)	(75)	(84)
6	(58)	(55)	(40)	(45)	(179)	(309)	(295)	(320)	(315)	(155)	(57)	(56)
7	(31)	(43)	(49)	(44)	(214)	(307)	(311)	(355)	(334)	(177)	(57)	(35)
8	33	21	11	13	1	(6)	(17)	(9)	(9)	(8)	17	20
9	25	23	11	20	(2)	(5)	(12)	(10)	(6)	(10)	19	10
10	24	25	14	26	(9)	(15)	(21)	(17)	(10)	(13)	22	8
11	24	27	18	24	(20)	(31)	(36)	(27)	(21)	(22)	21	4
12	23	20	20	30	329	537	473	527	520	296	21	(2)
13	18	21	13	17	192	304	293	327	306	193	22	4
14	14	14	(7)	(6)	58	113	76	145	138	50	17	7
15	6	1	(18)	(23)	15	44	48	72	51	40	13	17
16	31	18	19	14	57	82	101	93	101	91	40	52
17	52	34	34	21	55	69	93	92	84	101	51	62
18	36	33	47	38	36	31	36	23	23	33	36	43
19	27	29	35	31	38	39	43	21	13	20	27	33
20	20	20	27	25	26	30	32	8	4	13	17	24
21	6	8	20	19	2	-	(2)	(5)	(10)	(11)	6	8
22	(1)	3	(3)	-	(20)	(10)	(13)	(13)	(23)	(30)	(6)	-
23	(17)	(10)	(8)	(12)	(32)	(32)	(34)	(35)	(41)	(47)	(15)	(9)

Shading represents maximum hourly net discharge /charge (kW) across Figure 5-2 and Figure 5-3:

Minimum	(1,385)	(665)	56	777	1,497	Maximum

Ideal dispatch using the System Cost Dispatch is shown in Figure 5-3. If nonresidential AES projects were dispatched with perfect information in 2017 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 8 am, as customer loads start to increase but before solar production has begun, and in the evening (5 – 8 pm), when the utilities' marginal costs are highest.

FIGURE 5-3: OPTIMIZED AES NET DISCHARGE (CHARGE), AGGREGATED KW ACROSS SAMPLE (N=234) – SYSTEM COST DISPATCH

Month

Hour Beginning	1	2	3	4	5	6	7	8	9	10	11	12
0	(10)	(10)	(309)	(308)	(203)	(157)	(151)	(52)	(83)	(140)	5	(25)
1	(236)	(371)	(1,156)	(1,300)	(1,026)	(695)	(270)	(637)	(400)	(905)	(402)	(307)
2	(1,135)	(1,178)	(1,250)	(1,121)	(1,033)	(921)	(905)	(1,020)	(767)	(1,074)	(854)	(1,006)
3	(1,047)	(1,003)	(384)	(43)	(36)	(214)	(680)	(489)	(399)	(229)	(772)	(887)
4	(83)	(9)	(7)	272	337	159	(20)	(1)	4	3	(38)	(29)
5	4	37	909	1,288	1,049	409	49	156	423	782	119	-
6	544	988	1,421	807	505	(71)	(269)	48	278	1,035	956	930
7	1,027	1,003	240	-	(102)	(461)	(603)	(381)	(215)	28	446	923
8	127	-	(42)	(39)	(106)	(492)	(379)	(606)	(831)	(725)	(20)	-
9	-	12	(453)	-	(48)	(166)	(16)	(221)	(827)	(1,260)	(370)	-
10	(36)	(79)	(712)	(637)	(908)	(197)	-	(20)	(322)	(825)	(442)	(62)
11	(102)	(388)	(526)	(820)	(1,160)	(248)	-	(49)	(143)	(169)	(478)	(678)
12	(1,172)	(1,129)	(620)	(878)	(621)	(129)	-	-	-	(137)	(961)	(1,385)
13	(1,155)	(793)	(630)	(557)	(150)	(30)	(5)	8	-	(17)	(500)	(1,024)
14	(254)	(394)	(352)	(347)	(177)	-	-	9	8	15	(97)	(64)
15	(20)	(68)	-	-	26	4	5	150	61	56	-	-
16	-	-	-	-	(31)	27	30	194	128	179	58	-
17	1,304	255	63	-	76	438	1,003	923	1,056	1,311	1,415	1,346
18	1,292	1,335	1,497	1,395	1,199	1,255	1,422	1,230	1,173	1,074	1,080	1,248
19	21	801	1,117	1,205	1,319	823	171	115	129	-	-	38
20	2	-	-	-	85	21	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-	-	-	-
22	-	-	-	(43)	-	-	-	-	-	-	-	-
23	(4)	(9)	(71)	(66)	(84)	(94)	-	-	(2)	(3)	(42)	(9)

SHADING REPRESENTS MAXIMUM HOURLY NET DISCHARGE /CHARGE (KW) ACROSS FIGURE 5-2 AND Figure 5-3:

Minimum	(1,385)	(665)	56	777	1,497	Maximum

Note that the System Cost Dispatch results in significantly deeper net charge and discharge than the Customer Dispatch. This will be investigated further in the next section on capacity factor.

For the Carbon Dispatch approach, the AES projects are modeled to respond to a 5-minute signal – the marginal carbon emissions rate implied by CAISO's 5-minute real-time energy prices (See Appendix A for more details). This 5-minute signal means that many AES projects are modeled to both charge and discharge during the same hour. To provide an example of this intra-hour dispatch, Figure 5-4 and Figure 5-5 show an example AES project dispatch for the same hour (7 – 8pm) on a spring and a winter day, respectively.

FIGURE 5-4: OPTIMIZED AES DISCHARGE (CHARGE) AND STATE OF CHARGE (400 KW REBATED CAPACITY), MARCH 25, 2017 – CARBON DISPATCH APPROACH

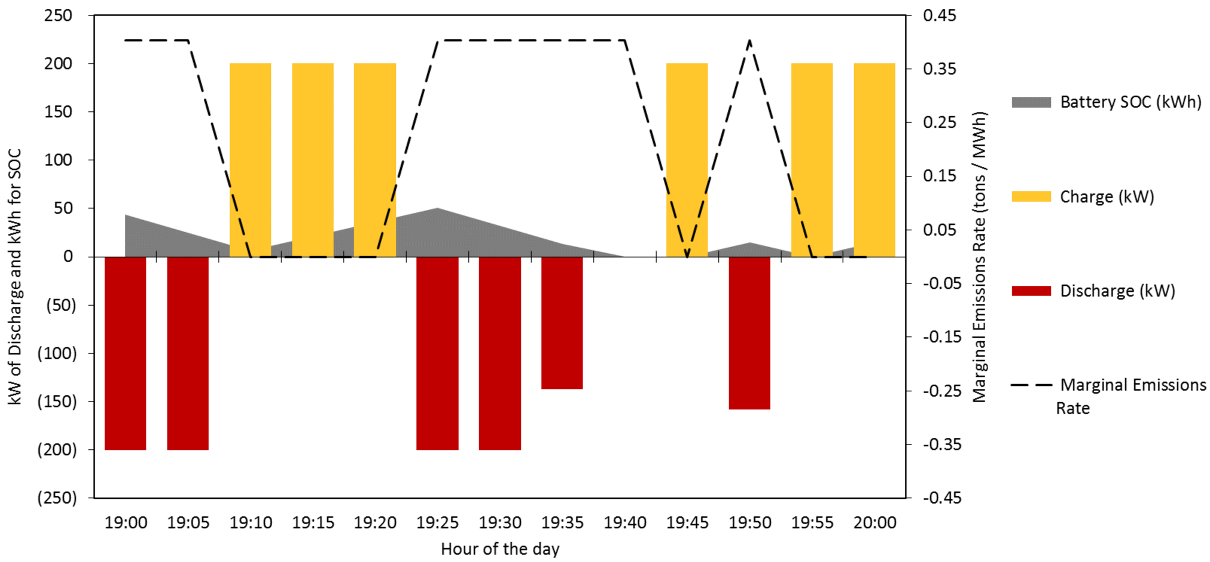
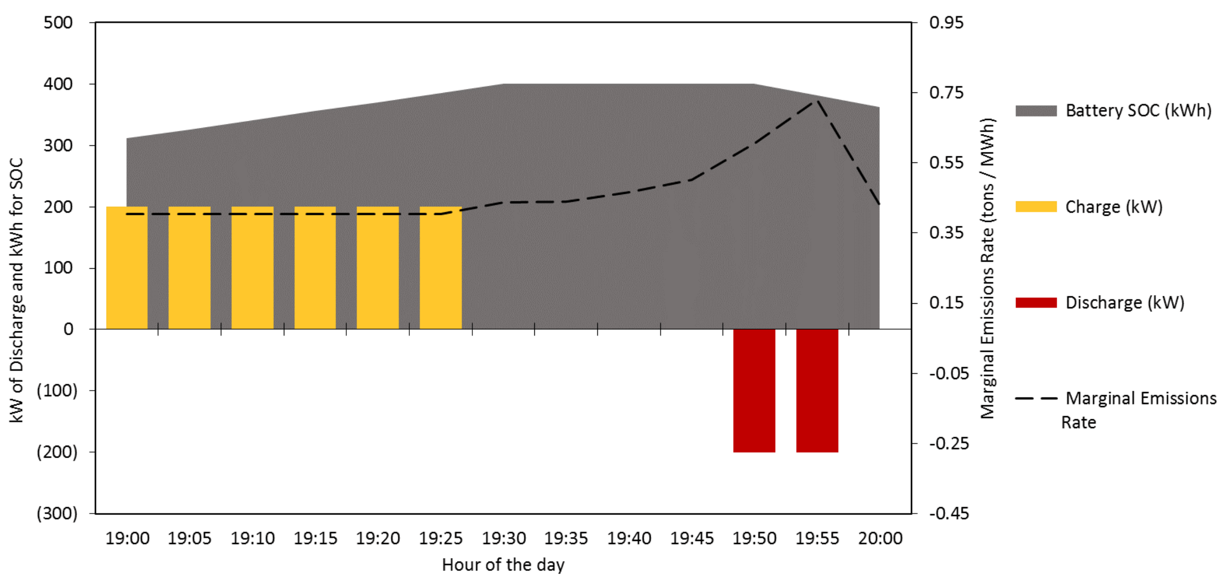


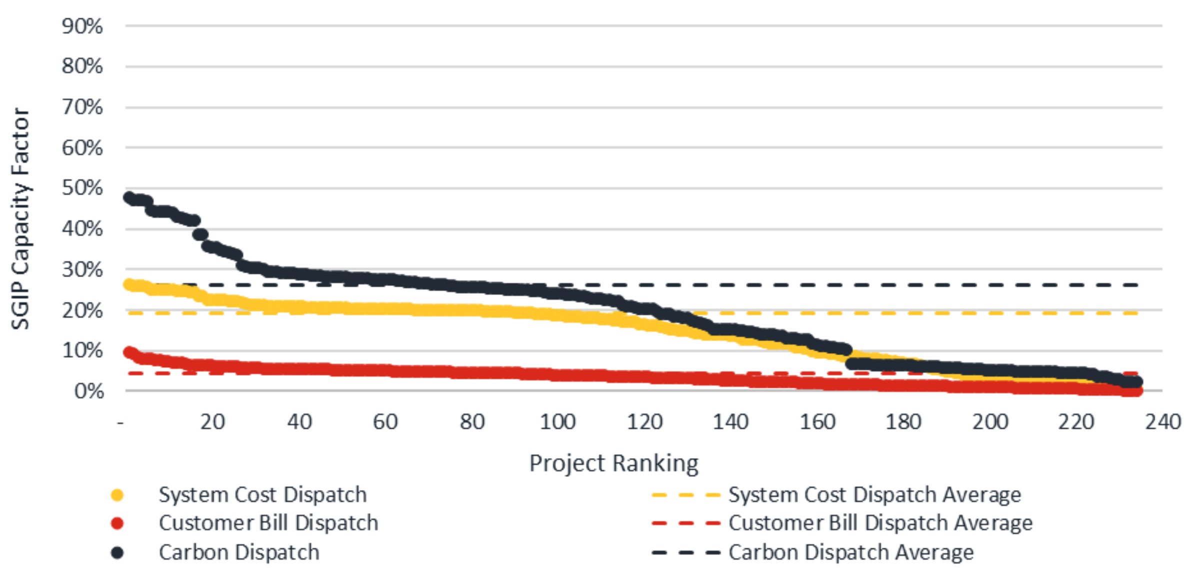
FIGURE 5-5: OPTIMIZED AES DISCHARGE (CHARGE) AND STATE OF CHARGE (400 KW REBATED CAPACITY), OCTOBER 4, 2017 – CARBON DISPATCH



5.3.2 Capacity Factors and Roundtrip Efficiencies Under Optimized AES Dispatch

We also examined how much the AES projects in the sample would have optimally been utilized in 2017 under each of the three Dispatch Approaches by calculating their theoretical SGIP Capacity Factors (see Figure 5-6). In this exercise, the SGIP Capacity Factor is calculated as the ratio of optimal discharge to maximum possible discharge over 60% of hours for the SGIP *rebated* capacity. This provides a measure of how much a project is utilized under optimal dispatch relative to its maximum potential use.

FIGURE 5-6: AES PROJECT SGIP CAPACITY FACTORS ASSUMING OPTIMAL DISPATCH, BY DISPATCH APPROACH (N=234)



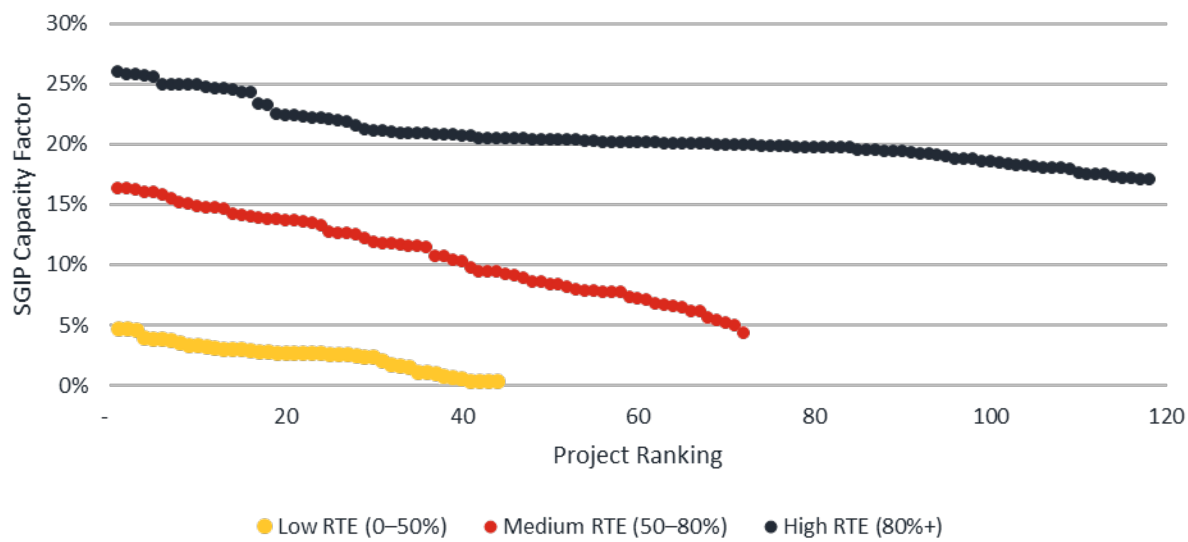
There are a number of things to note. Higher volatility in avoided cost, avoided CO_2 emissions or price leads to greater opportunities for arbitrage by the storage projects. Marginal costs and carbon dioxide emissions fluctuate on an hourly and sub-hourly basis, respectively, whereas TOU rates stay the same for multiple hours. Therefore, the simulated SGIP capacity factors for the System Cost and Carbon Dispatch approaches are generally higher than those for the Customer Bill Dispatch.

SGIP AES projects dispatched to minimize system costs have a maximum SGIP Capacity Factor of 26%. The majority of the system cost value is captured by these projects in a small number of high-cost hours that are generation capacity and/or distribution capacity constrained. Further, recall that the marginal emissions used for the Carbon Dispatch approach are based on 5-minute real-time energy prices, whereas the System Cost Dispatch approach uses *hourly* marginal energy costs. This causes less cycling of batteries for the System Cost versus the Carbon Dispatch approach, which leads to a lower SGIP capacity factor under the System Cost Dispatch.

Finally, note that all of the nonresidential AES projects in our sample show SGIP Capacity Factors of less than 10% when they are dispatched to minimize customers' bills against 2017 retail tariffs.

AES roundtrip efficiency (RTE) is also an important consideration related to storage project utilization. AES projects with higher single cycle RTEs are able to arbitrage across smaller differences in energy prices and carbon emissions because less of their discharge is going to battery losses. As shown in Figure 5-7, under optimal dispatch that minimizes marginal utility costs, projects with high RTEs (greater than 80%) would consistently have higher capacity factors than those with medium RTEs (greater than 50% but less than 80%), which in turn have higher capacity factors than low RTEs (0 – 50%) projects.

FIGURE 5-7: AES PROJECT SGIP CAPACITY FACTORS ASSUMING OPTIMAL DISPATCH, BY OBSERVED ROUND-TRIP EFFICIENCY (RTE) BIN – SYSTEM COST DISPATCH APPROACH (N=234)

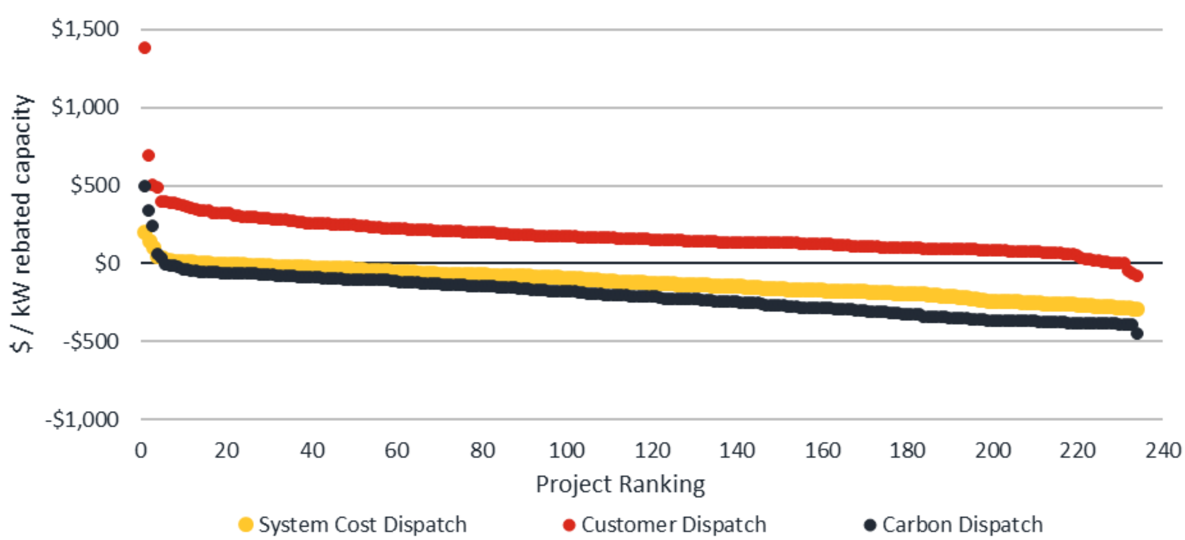


5.3.3 Maximum Potential Customer Bill Savings Achievable by Nonresidential AES Projects

We analyzed the customer bill savings that would have been generated by AES projects (on a per-kW rebated capacity basis) *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 or critical peak pricing programs, though we do subsequently investigate these.

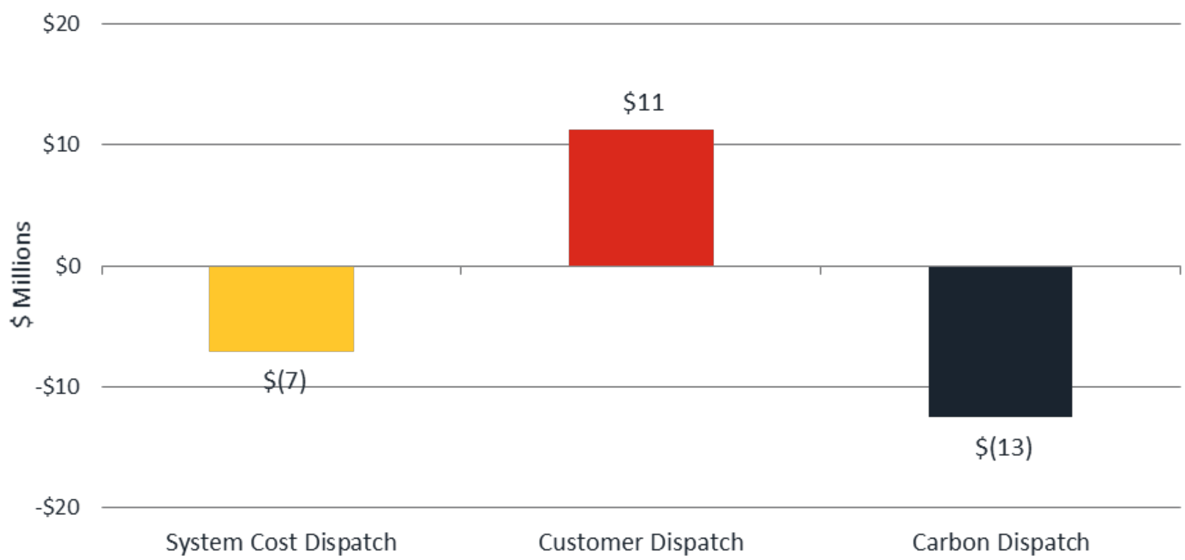
If the AES projects were dispatched to minimize customer bills, there would have been a few projects that provided very high customer bill savings per rebated kW (up to $1,383/kW) in 2017 (see Figure 5-8). Notably, under 2017 utility rates, the SGIP AES projects would only have achieved bill savings if optimized for bills – optimizing AES dispatch to minimize system marginal costs or to minimize carbon dioxide emissions would have led to a substantial increase in customer bills under 2017 rates. This suggests a mismatch between customer and system/societal incentives for storage dispatch.

FIGURE 5-8: DISTRIBUTION OF ANNUAL ELECTRICITY BILL SAVINGS ATTRIBUTABLE TO AES PROJECTS UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH, $ PER KW OF REBATED CAPACITY (N=234)



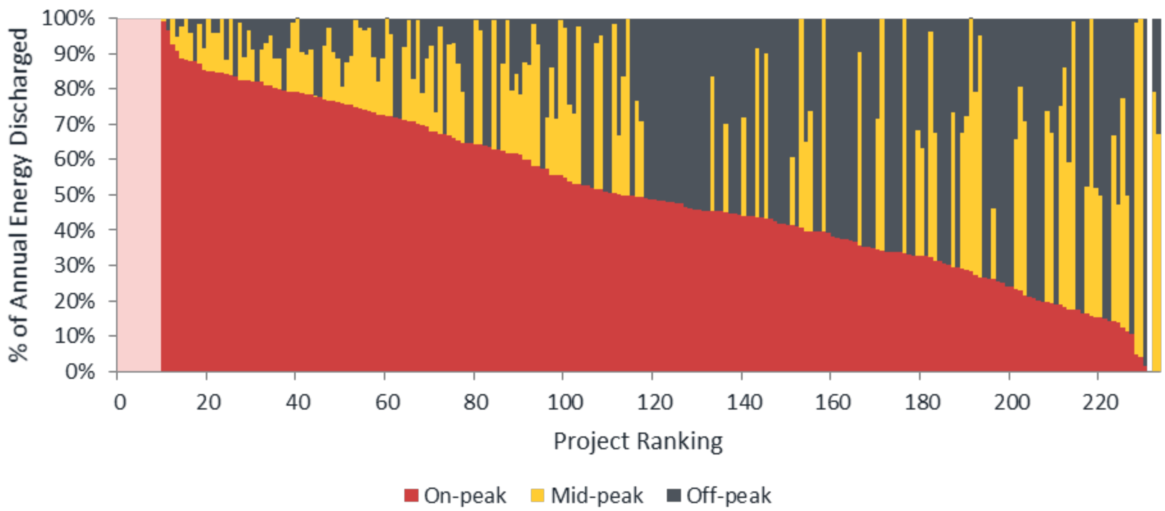
Scaling these sample results suggests that total potential bill savings to customers across the population of nonresidential SGIP AES projects would have been approximately $11 million in 2017, excluding bill savings from demand response and critical peak pricing programs, if these projects were optimally dispatched to minimize customer bills with perfect foresight (Figure 5-9). On average, this would have amounted to an annual bill savings of about approximately $29,600 per nonresidential SGIP storage project that was active in 2017.

FIGURE 5-9: ESTIMATED 2017 BILL SAVINGS ATTRIBUTABLE TO THE POPULATION OF NONRESIDENTIAL AES PROJECTS IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH ($2017 MILLIONS), EXCLUDING CPP/PDP AND DEMAND RESPONSE BENEFITS



These savings would have come from a combination of demand charge minimization and TOU period rate arbitrage. Figure 5-10 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 some ideally dispatched projects would devote the majority of their discharging to on-peak hours, only ten customers would discharge entirely on-peak and around half the projects would discharge less than 50% of their energy on-peak. The average energy discharged on-peak is 60% and the average energy discharged at mid-peak is 21%.

FIGURE 5-10: STORAGE DISCHARGE BY TOU PERIOD, IF OPTIMALLY DISPATCHED TO MINIMIZE CUSTOMER BILL (N=234)



*lighter red shade denotes projects served by tariffs that do not include demand charges

The implication of this finding is significant. Despite the understanding that TOU rates are designed to influence the timing of a customer's load, TOU rates paired with non-coincident demand charges can undermine the extent to which the timing of customers' load can be influenced. While non-coincident 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, non-coincident 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.

Additional Potential Benefits to Customers from Demand Response Participation

We also ran an additional analysis to estimate the added potential benefit to customers participating in CPP/PDP and other demand response (DR) programs, if they ideally dispatched their projects with perfect information.

The sample for the CPP/PDP analysis contained 36 customers that participated in Critical Peak Pricing (CPP) or Peak Day Pricing (PDP) programs. These programs are designed to reduce demand during certain hours via a rate adder which applies to customer tariffs only on CPP event days. The number of CPP/PDP event days and the duration of the rate adder varies by IOU. Table 5-9 provides a summary of the programs for each IOU.

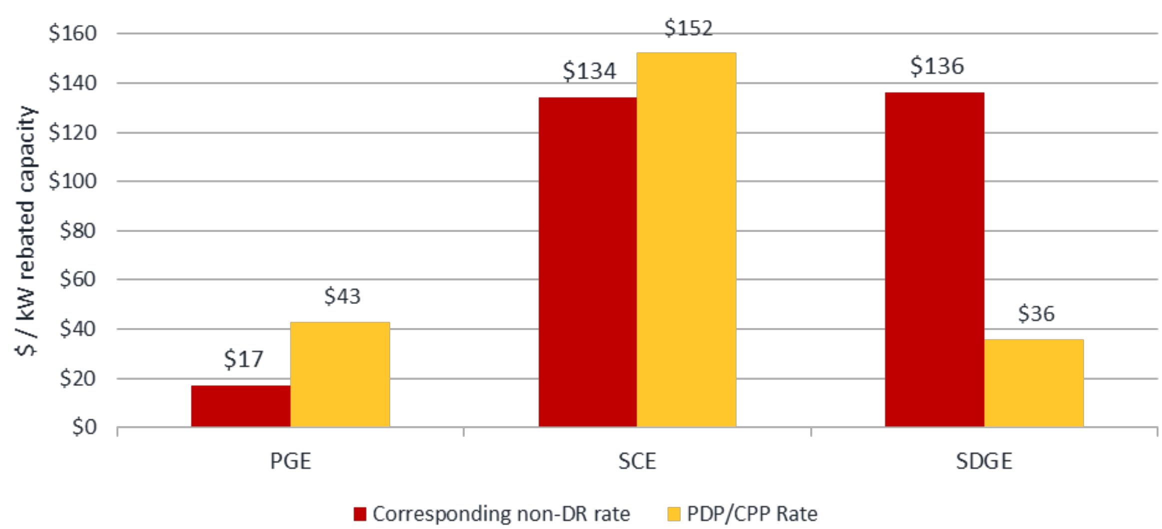
TABLE 5-9: CPP / PDP PROGRAM DATA

IOU and Program	Number of Customers	Maximum CPP Events Allowed Under Each Tariff	Actual CPP Events Issued in 2017	Event Duration (hours)
PG&E PDP program	6	15	15	4
SCE CPP program	5	12	12	4
SDG&E CPP program	25	18	3	7

For our CPP/PDP analysis, we simulated these programs using information from the utilities' tariff sheets, including compensation levels as well as the number and duration of peak pricing events.

We calculated the bill savings that could have been achieved under optimal dispatch by the 36 customers in our sample that were on a CPP/PDP tariff during 2017 and compared this to the savings that would have been achieved on a corresponding non-CPP rate. The results are shown in Figure 5-11. The results show that if SDG&E customers did not participate in CPP and instead were on the most similar available alternative tariff, they would have in fact achieved greater bill savings. This is because the SDG&E alternative tariff is very different, with much higher demand charges, than the CPP rate. Our analysis suggests that if these SDG&E customers were able to dispatch their AES optimally with perfect foresight, the value from reducing this demand charge would outweigh the benefits received from the CPP program. This difference is amplified by the fact that SDG&E only called 3 events in 2017, amounting to 21 hours of participation over the year. SCE and PG&E had many more event calls - 48 hours and 60 hours, respectively – making these CPP programs more lucrative for customers. SCE's and PG&E's non-CPP alternative tariffs are also closer to their CPP/PDP tariffs.

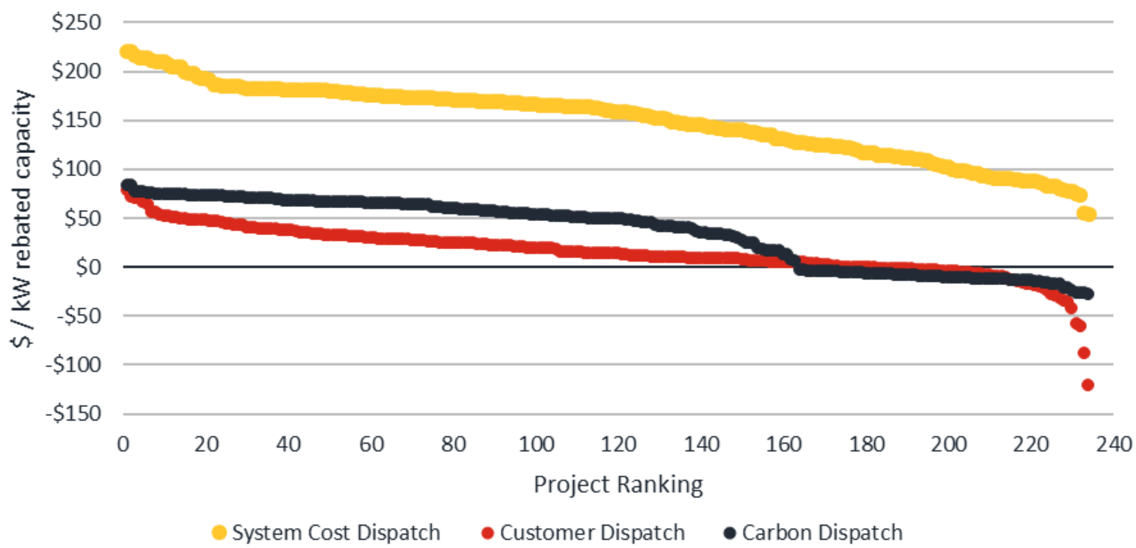
FIGURE 5-11: ESTIMATED 2017 BILL SAVINGS ATTRIBUTABLE TO THE SAMPLE OF NONRESIDENTIAL AES PROJECTS PARTICIPATING IN CPP OR PDP PROGRAMS -- CUSTOMER DISPATCH APPROACH (N = 36)



5.3.4 Potential System Avoided Costs Achievable by AES Projects

Our analysis of the sample of 234 nonresidential AES projects revealed that the system-level savings that could potentially have been realized in 2017 range from $54/kW to $220/kW *if* the projects were dispatched to minimize system avoided costs (Figure 5-12). Each marker on the figure represents an AES project in our sample. Most potential values are above $100/kW.

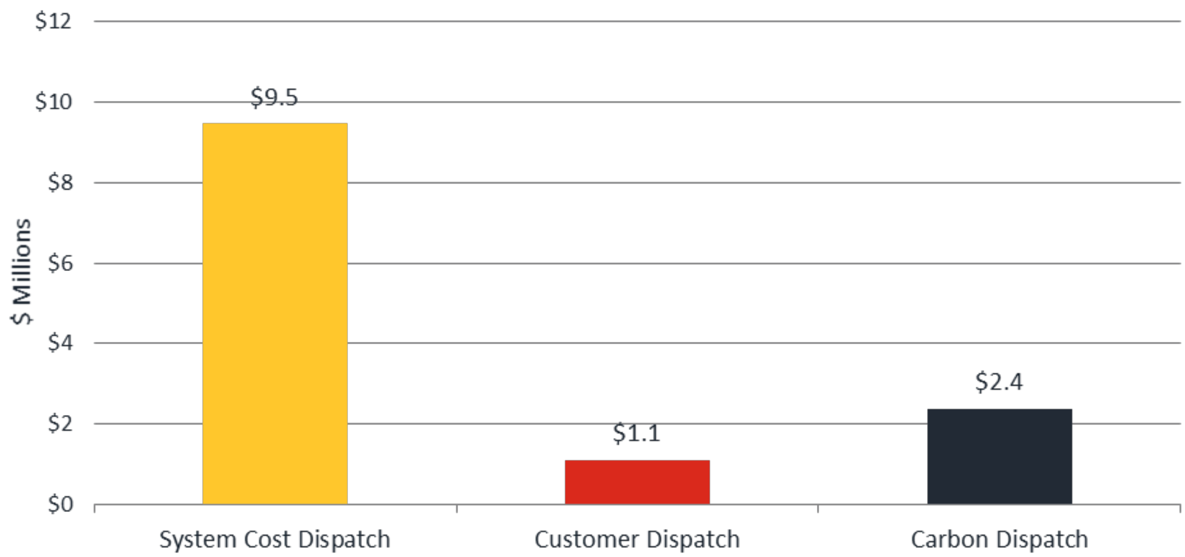
FIGURE 5-12: DISTRIBUTION OF SYSTEM AVOIDED COSTS ATTRIBUTABLE TO AES PROJECTS IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH, $ PER KW OF REBATED CAPACITY (N=234)



As shown in Figure 5-13, scaling up our 234-project sample to the nonresidential population of AES SGIP projects yields significant potential system cost savings – if the full population of nonresidential SGIP AES projects operating in 2017 were optimized on an hourly basis to minimize system marginal costs with perfect foresight, we estimate that we would have saved approximately $9.5 million in system costs in 2017. On the other hand, optimizing dispatch to minimize customer bills would have saved only $1.1 million in system costs over the year. Optimizing dispatch to minimize carbon dioxide emissions would have yielded net savings of about $2.4 million in 2017. Again, this suggests a disconnect between system costs, CO_2 emissions signals and customer rates.

The significant difference between avoided costs when AES is dispatched to minimize system costs versus CO_2 occurs because AES projects are capturing the majority of their avoided cost value in a small number of high-cost hours that are generation capacity and/or distribution capacity constrained. While there is some positive correlation between these periods and periods of high CO_2 emissions, our results indicate that this correlation is far from 100 percent. A secondary consideration is that our CO_2 signal is based on a five-minute signal, whereas system avoided costs are modeled hourly. Modeling energy prices on a five-minute basis would be expected to increase system avoided costs under the System Cost Dispatch approach, further increasing the difference in result between the two approaches.

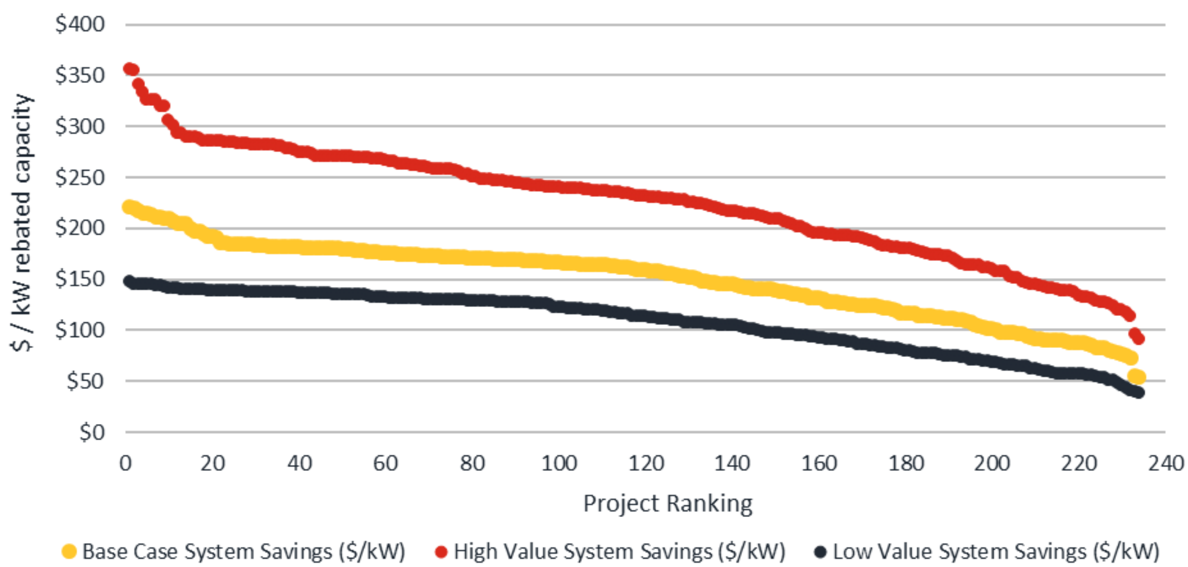
FIGURE 5-13: ESTIMATED 2017 SYSTEM AVOIDED COSTS ATTRIBUTABLE TO THE POPULATION OF NONRESIDENTIAL SGIP AES PROJECTS OPERATING IN 2017 IF OPERATED UNDER OPTIMAL DISPATCH, BY OPTIMIZATION APPROACH, $2017 MILLIONS



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.

Recall that this analysis was completed with the 2017 marginal distribution costs from the 2018 DER Avoided Cost Calculator. We also undertook distribution cost sensitivity analyses that examine the impact on total system avoided costs if the distribution value assumed for all projects is low ($20/kW-yr) or very high ($250/kW-yr.). Those results are shown in Figure 5-14.

FIGURE 5-14: DISTRIBUTION OF SYSTEM AVOIDED COSTS ATTRIBUTABLE TO AES PROJECTS IF OPERATED UNDER OPTIMAL DISPATCH, FOR LOW/MEDIUM/HIGH DISTRIBUTION VALUE, $ PER KW OF REBATED CAPACITY (N=234)



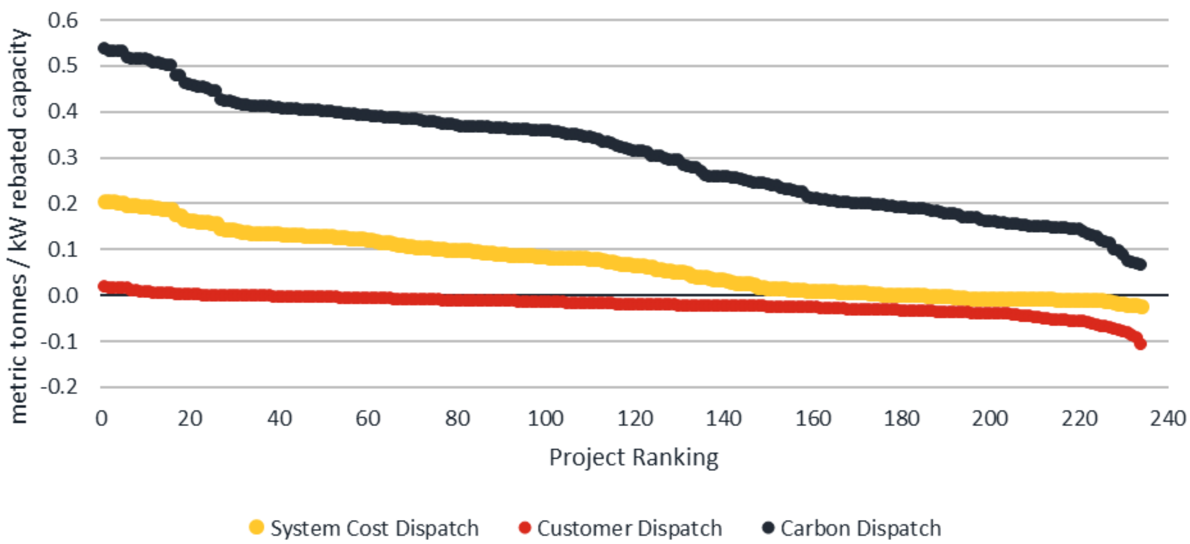
5.3.5 Potential Carbon Dioxide Savings Attributable to AES Projects

As described in Section 5.2, we ran two Carbon Dispatch optimizations, which differ by the natural gas plant heat rate range that was used in the calculation of marginal CO_2 emissions. Both provided very similar results.

Our base case uses the heat rate ranges from the Avoided Cost Calculator. Unsurprisingly, optimizing AES dispatch to minimize carbon dioxide emissions results in emissions savings from every AES project in our sample. In other words, all projects included in our sample could have reduced CO_2 emissions if their dispatch had been optimized to do so (Figure 5-15).

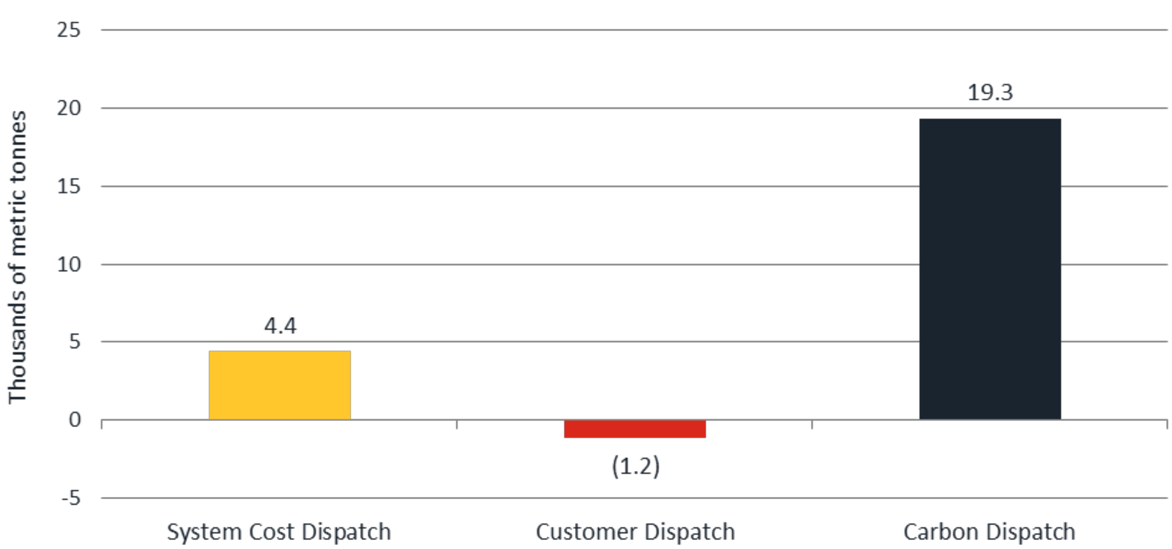
Under our base case heat rate assumptions, the savings ranged from 0.067 to 0.54 metric tons per kW of rebated capacity. If the projects are instead dispatched to minimize system costs, they will discharge during high marginal cost hours. These high-cost hours often align with peak net load hour when more inefficient plants are running, so the System Cost optimization does result in a net reduction of CO_2 emissions for 180 of the 234 projects (77%) in our sample. If storage projects are dispatched to minimize customer bills against each customer's 2017 tariffs, then CO_2 emissions will actually increase. This is because the on-peak TOU periods in 2017 were aligned with hours of high solar generation and low marginal emissions.

FIGURE 5-15: CO_2 EMISSIONS SAVINGS BY NONRESIDENTIAL AES PROJECT, IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH (N=234)



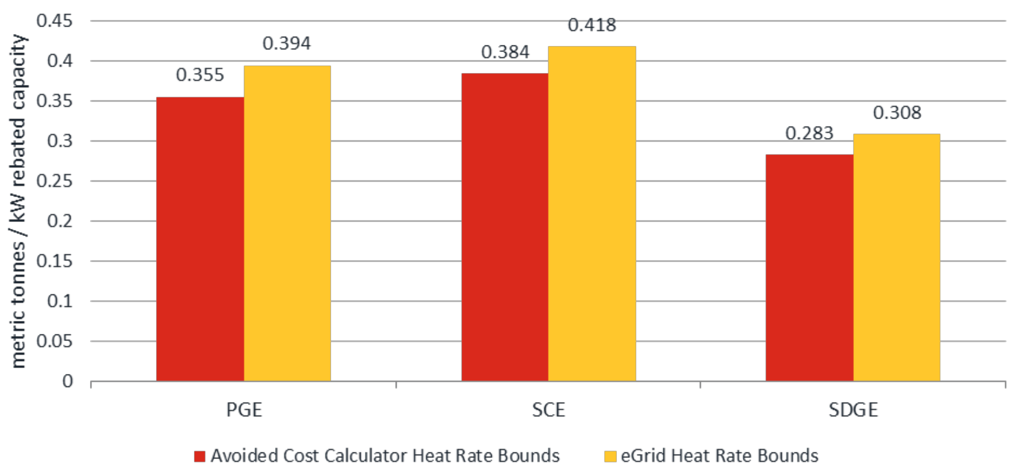
Scaling these results suggests that the maximum potential avoided emissions in 2017 across the population of nonresidential AES SGIP projects would have been 19,300 metric tons of CO_2 (see Figure 5-16). Optimally dispatching the AES projects to minimize system costs also would have resulted in CO_2 savings (approximately 4,400 tons), while optimizing to minimize customer bills under 2017 rates would have *increased* CO_2 emissions by around 1,200 tons.

FIGURE 5-16: ESTIMATED 2017 AVOIDED CO_2 EMISSIONS ATTRIBUTABLE TO THE POPULATION OF NONRESIDENTIAL SGIP AES PROJECTS IF OPERATED UNDER OPTIMAL DISPATCH, BY DISPATCH APPROACH



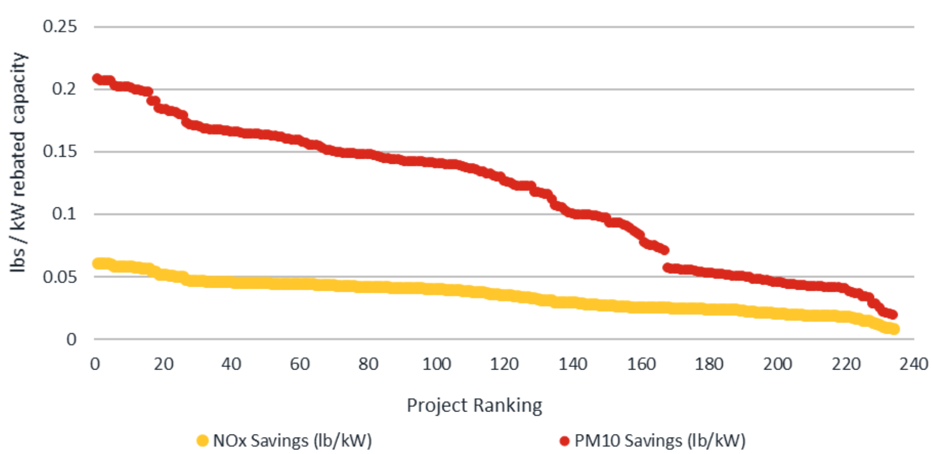
We then examined the impact of changing the heat rate range used in calculating the marginal CO_2 emissions. This sensitivity uses the EPA's latest eGRID data for California to define a more efficient high-efficiency plant (5,641 vs. 6,900 from the Avoided Cost Calculator). As shown in Figure 5-17, this change does not make a significant difference to the emissions savings achieved by the AES projects under optimal dispatch.

FIGURE 5-17: CO_2 EMISSIONS SAVINGS PER KW OF REBATED CAPACITY IF OPTIMIZED FOR CARBON DIOXIDE EMISSION REDUCTIONS (N=234)



We have also conducted an examination of potential criteria pollutant savings (NOx and PM_{10}) when projects are dispatched to minimize carbon emissions. Those results are shown in the figure below.

FIGURE 5-18: ESTIMATED 2017 AVOIDED NOX AND PM10 EMISSIONS BY NONRESIDENTIAL AES PROJECT, IF OPERATED UNDER OPTIMAL DISPATCH, CARBON DISPATCH APPROACH (N=234)



SUMMARY RESULTS OF OPTIMIZED DISPATCH

The total potential savings attributed to SGIP AES projects under ideal dispatch are summarized in Table 5-10 below.

TABLE 5-10: ESTIMATED POPULATION-LEVEL IMPACT OF NONRESIDENTIAL AES PROJECTS, 2017

	Customer Bill Dispatch Approach	System Cost Dispatch Approach	Carbon Dispatch Approach
Net Customer Bill Savings (Cost) ($ Millions)	$11.3	(7.1)	($12.6)
Net System Benefit (Cost) ($ Millions)	$1.1	$9.5	$2.4
Avoided (Increased) CO_2 Emissions (Metric Tons)	(1,157)	4,387	19,348

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.

5.3.6 Modeling Alternative Incentives that are More Dynamic

Recall that the system marginal costs used in this analysis from E3's Avoided Cost Calculator represent the marginal cost of delivering energy in each hour, including an allocation of capacity and transmission costs to peak load hours (Section 5.2). Figure 5-19 shows the monthly average system marginal costs overlayed with SCE's TOU periods in 2017.

FIGURE 5-19: 2017 SCE TOU PERIODS AND AVERAGE HOURLY CPUC MARGINAL COSTS FOR DER IN 2017 (PACIFIC LOCAL TIME, HOUR BEGINNING) [10]

Hour Beginning \ Month	1	2	3	4	5	6	7	8	9	10	11	12
0	$58	$52	$44	$50	$52	$52	$58	$59	$59	$60	$64	$61
1	$57	$50	$41	$47	$49	$51	$57	$58	$58	$59	$61	$60
2	$56	$48	$41	$48	$49	$50	$56	$58	$58	$58	$60	$59
3	$56	$49	$45	$54	$53	$53	$56	$58	$58	$59	$60	$59
4	$57	$52	$56	$68	$63	$58	$58	$60	$61	$64	$63	$60
5	$63	$60	$69	$80	$69	$59	$60	$66	$68	$76	$71	$67
6	$72	$70	$77	$69	$59	$53	$58	$64	$66	$78	$83	$84
7	$77	$71	$58	$48	$47	$48	$55	$59	$57	$64	$73	$82
8	$67	$57	$43	$40	$44	$48	$57	$59	$54	$56	$63	$66
9	$61	$48	$34	$37	$43	$51	$59	$62	$54	$54	$60	$61
10	$56	$43	$32	$21	$29	$54	$62	$65	$56	$56	$59	$58
11	$54	$41	$32	$20	$30	$56	$65	$68	$60	$59	$59	$56
12	$50	$39	$32	$21	$32	$60	$70	$73	$128	$62	$59	$55
13	$51	$41	$34	$23	$35	$64	$74	$82	$480	$523	$60	$56
14	$54	$42	$34	$24	$38	$69	$79	$270	$993	$606	$62	$58
15	$62	$50	$40	$42	$56	$79	$84	$718	$1,373	$688	$70	$65
16	$72	$61	$53	$52	$62	$84	$88	$789	$1,271	$570	$92	$86
17	$92	$80	$78	$79	$81	$101	$99	$345	$941	$310	$131	$114
18	$91	$92	$100	$110	$104	$124	$111	$151	$360	$127	$108	$110
19	$84	$81	$86	$99	$106	$100	$91	$102	$140	$95	$92	$100
20	$80	$77	$75	$83	$84	$81	$81	$81	$76	$83	$86	$95
21	$73	$69	$64	$69	$68	$67	$70	$72	$69	$74	$77	$84
22	$67	$62	$55	$59	$59	$61	$64	$66	$65	$68	$71	$74
23	$62	$56	$47	$53	$54	$56	$61	$62	$61	$63	$65	$65

Super Off Peak / Off Peak / On Peak / Super Off Peak

As California reaches higher and higher penetrations of renewable generation, these marginal costs are expected to change significantly. The IOUs have proposed to modify their TOU periods to account for excess solar generation during the day and peak net loads that occur later in the evening. As of the time of this writing, the CPUC is still in the process of approving PG&E and SCE's modified TOU periods and has approved SDG&E's proposal, but none of the AES projects in our sample were on this rate in 2017.[11] Shifting the on-peak TOU period to later in the day should assist in incentivizing storage to better alleviate load in more of the high system marginal cost hours (i.e., hour beginning 18 and 19 in August and September) that fall outside the current on-peak TOU period. Figure 5-20, for example, shows the revised TOU periods proposed by SCE, overlaid on system marginal costs for 2030.[12] SCE has proposed a super

10 2016 CPUC avoided costs for climate zone 9: Burbank-Glendale

11 See http://www.cpuc.ca.gov/General.aspx?id=12141

12 CPUC Rulemaking 12-06-013

off-peak period in the winter between hour beginning 8 and hour beginning 15 when excess renewable generation is most likely to occur.

FIGURE 5-20: PROPOSED SCE TOU PERIODS AND AVERAGE HOURLY MARGINAL SYSTEM COSTS FOR DER IN 2030[13]

Month

Hour Beginning	1	2	3	4	5	6	7	8	9	10	11	12
1	$107	$103	$86	$92	$95	$96	$109	$108	$111	$114	$120	$115
2	$105	$98	$80	$86	$90	$94	$108	$106	$107	$112	$116	$113
3	$103	$94	$80	$88	$91	$94	$105	$105	$108	$111	$114	$111
4	$103	$95	$88	$100	$97	$98	$106	$106	$107	$113	$114	$111
5	$105	$103	$112	$122	$115	$109	$110	$112	$115	$121	$117	$113
6	$115	$117	$139	$146	$125	$108	$113	$121	$127	$143	$130	$125
7	$128	$140	$159	$44	$22	$4	$108	$114	$120	$147	$161	$160
8	$138	$140	$22	$4	$0	$0	$2	$4	$0	$118	$140	$152
9	$122	$2	$0	$0	$0	$0	$4	$10	$0	$4	$18	$123
10	$0	$0	$0	$0	$0	$2	$7	$13	$2	$0	$9	$7
11	$0	$0	$0	$47	$78	$6	$20	$18	$7	$11	$6	$4
12	$0	$0	$0	$43	$79	$12	$30	$26	$14	$12	$8	$2
13	$0	$0	$0	$43	$82	$17	$48	$37	$19	$15	$10	$2
14	$0	$0	$0	$48	$88	$24	$58	$53	$41	$335	$12	$3
15	$0	$0	$0	$50	$93	$35	$62	$98	$201	$703	$16	$4
16	$0	$0	$0	$2	$19	$56	$70	$115	$630	$1,392	$137	$123
17	$128	$118	$5	$4	$22	$65	$82	$243	$840	$1,300	$184	$166
18	$158	$153	$154	$65	$73	$102	$197	$555	$2,852	$811	$275	$231
19	$157	$182	$215	$221	$206	$235	$312	$1,020	$2,101	$258	$222	$224
20	$144	$156	$172	$191	$204	$188	$222	$367	$676	$184	$186	$203
21	$137	$147	$150	$147	$151	$146	$147	$158	$146	$157	$167	$185
22	$128	$132	$125	$120	$119	$120	$125	$130	$126	$136	$147	$160
23	$120	$121	$110	$106	$108	$111	$116	$120	$118	$125	$134	$136
24	$113	$110	$94	$96	$99	$103	$114	$114	$113	$118	$124	$120

Off Peak

Super Off Peak

Mid Peak

On Peak

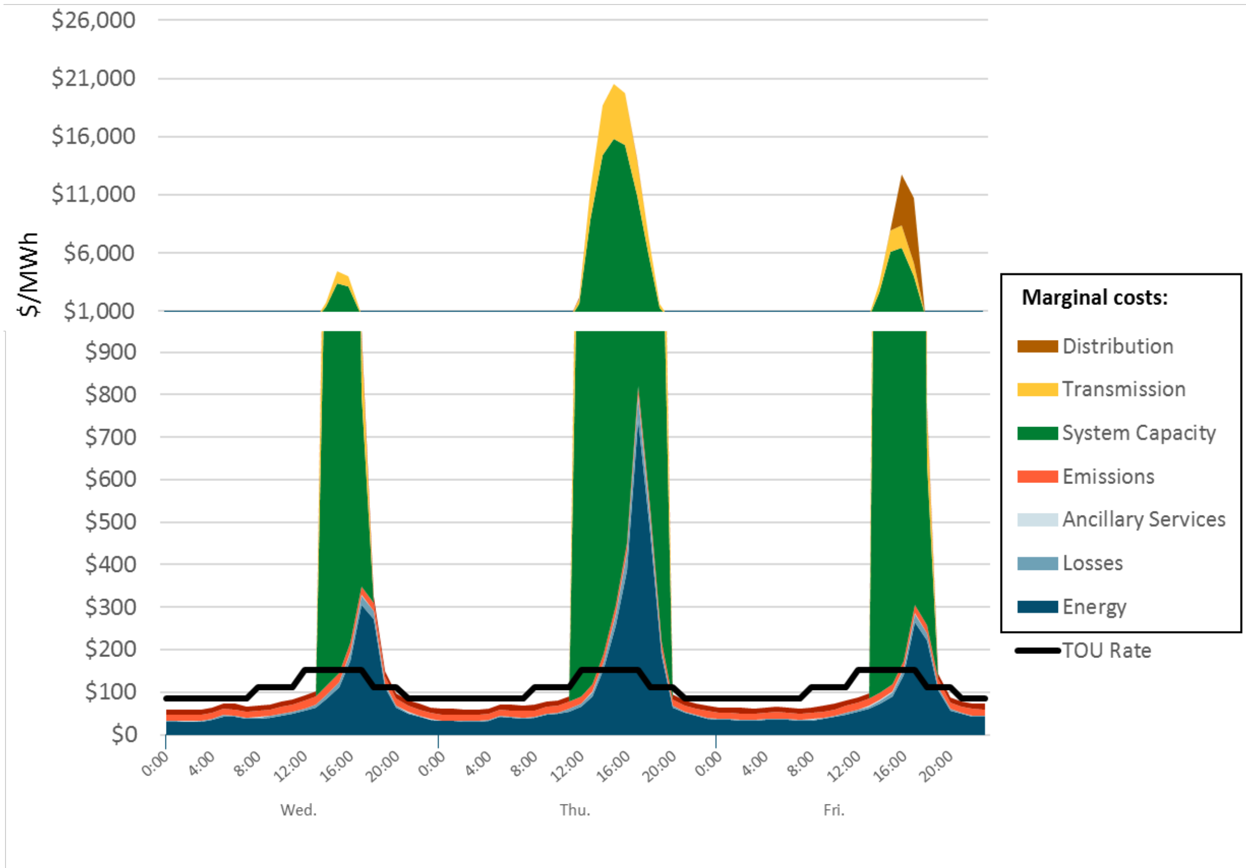
Off Peak

Broad TOU rate periods, however, will not fully harness the potential for highly flexible resources like AES to support the grid during those specific hours with the highest marginal costs. Figure 5-21 shows an example PG&E TOU rate (E19S) compared to the 2017 CPUC avoided costs in Fresno for three summer days. On the first day, high system capacity value is concentrated in the four hours between 2 and 6 PM. The next day, local transmission and distribution capacity costs drive a significantly higher value concentrated between 12 and 8 PM. For the third day, highest system marginal costs are concentrated between 2 and 7pm. Focusing AES discharge in these 17 total hours out of 72 would maximize the value

13 2030 CPUC avoided costs for climate zone 9: Burbank-Glendale

to the grid. These hours are somewhat aligned with PG&E's TOU periods, but not completely. The TOU periods provide an equal incentive for AES to discharge beginning at noon and steps down at 6 PM.

FIGURE 5-21: THREE-DAY SNAPSHOT OF PG&E TOU RATES AND CPUC MARGINAL COSTS IN 2017[14]



Even with modified periods to reflect increasing solar generation, TOU rates do not harness the potential for highly flexible resources like AES to support the grid during those specific hours with the highest marginal costs. TOU rates provide an on-peak price that is averaged over a relatively broad period of six to eight hours in the day over four to six summer months without special emphasis on the very highest system peak load hours. More dynamic rates can significantly increase the grid value realized from AES.

To illustrate this point, we modeled a) the potential impact of perfectly-executed CPP/PDP programs on system costs, and b) the impacts of more dynamic tariffs that have been proposed or approved for each utility.

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14 Climate Zone 13 – Fresno and PG&E E19S Rate

Modeling Nonresidential AES projects on Alternative Tariffs

To analyze the potential impact of the CPP or PDP programs on system costs, we ran the Customer Bill Dispatch approach for the 36 nonresidential customers in our sample that participated in these programs in 2017. The rate selected for comparison was the most similar tariff option available for each IOU, which sometimes differed quite significantly to the CPP rate.

We used the 2017 hourly costs published in the 2018 DER Avoided Cost Calculator to choose *when* the CPP/PDP events would have been optimally called in our simulation. That is, we 'called' the actual number of CPP/PDP events (15 for PG&E, 12 for SCE and 3 for SDG&E) for the specified event duration using the 2017 hours of highest system cost from the Avoided Cost Calculator. Using our avoided cost data to simulate the timing of CPP/PDP events rather than real event calls assumes perfect information than the utilities are actually able to use. In reality, CPP customers are informed of an event the day before it is called, meaning IOUs rely on day-ahead system cost forecasts to issue events. These day-ahead forecasts do not always match real-time data. IOUs also have a limited number of events they can call each year, so judgement is required when timing event calls to ensure they are not all used too early, rationed too strictly or not used at all. Since RESTORE is a perfect foresight optimization model, these forms of forecasting error are not accounted for. This means that our CPP/PDP results, as with all results in this section, represent optimal dispatch based on perfect foresight.

Recall that our RESTORE model assumes that CPP/PDP event calls are perfectly aligned with system costs (i.e. it does not capture realities of forecast error). Still, the results demonstrate that, provided event days coincide with peak system costs and customers respond to event calls, then the CPP/PDP programs could increase avoided costs significantly compared with the closest alternative non-CPP rate. See Figure 5-22.

FIGURE 5-22: ESTIMATED 2017 SYSTEM COST SAVINGS ACHIEVABLE BY THE SAMPLE OF NONRESIDENTIAL AES PROJECTS PARTICIPATING IN CPP OR PDP PROGRAMS – CUSTOMER BILL DISPATCH APPROACH (N = 36)

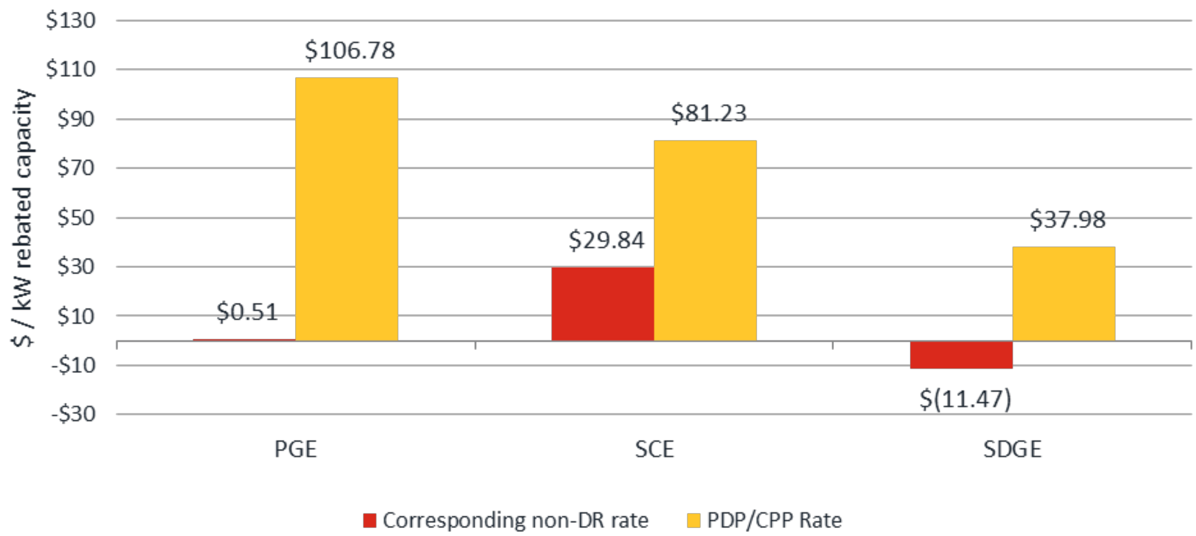
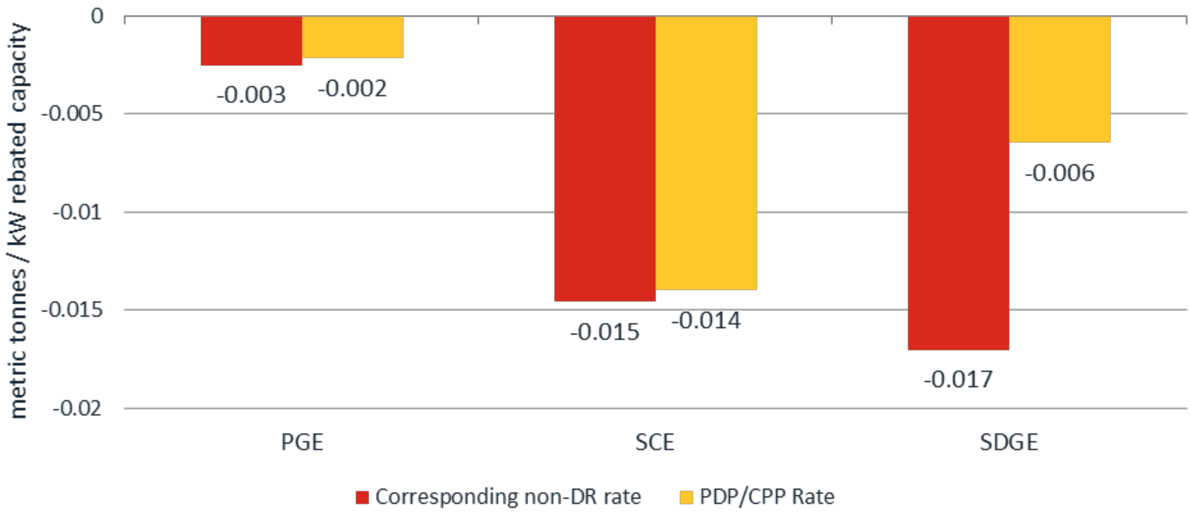


Figure 5-23 shows the impact of CPP/PDP programs on CO_2 emissions when dispatch is optimized to minimize customer bills. As shown in the figure, minimizing customer bills leads to slight CO_2 increases for both non-CPP/PDP customers and CPP/PDP customers. Customers optimally dispatching to minimize their bills in response to PDP/CPP rates would generate very slightly lower emissions than customers on the closest alternative tariff. Since the event calls for this analysis are timed perfectly with avoided cost peaks throughout the year, this simply demonstrates that system costs are at least somewhat positively correlated with CO_2 emissions. The impact is much more pronounced for SDG&E customers. As discussed above, the closest alternative tariff is markedly different from the PDP/CPP tariff.

FIGURE 5-23: CO_2 SAVINGS PER KW OF REBATED CAPACITY FROM THE SAMPLE OF NONRESIDENTIAL AES PROJECTS PARTICIPATING IN CPP OR PDP PROGRAMS – CUSTOMER BILL DISPATCH APPROACH (N = 36)



In addition to the CPP/PDP impacts, we also modeled for each utility the potential impacts of an approved or proposed rate designed to better align with system costs. We selected one such rate per utility to analyze:

- PG&E has proposed new TOU periods, including an on-peak period from 4 to 7 PM. We selected their revised E19S rate from the various newly-proposed PG&E nonresidential rates. Medium-size demand-metered customers are eligible for the E19S rate.
- SCE's TOU-8 rate has a real-time pricing (RTP) option, which provides a pre-determined hourly energy price signal that varies based on weather conditions in addition to standard energy and demand charges. Large customers are eligible for this rate.
- SDG&E's Grid Integration Rate (GIR), an electric vehicle pilot rate whose results are currently being used to inform the implementation process for dynamic rates in SDG&E, comprises a day-ahead hourly price signal and adders for peak system and distribution capacity hours.

We ran the Customer Dispatch approach with these more "dynamic" rates on the subset of customers in our sample that were subscribed to an analogous tariff option in 2017. Note that we did not screen these customers to determine whether they would be eligible for the "dynamic" tariffs used in this analysis – the objective of this analysis was to show the potential avoided costs under each of these tariffs rather than assessing real-world match between individual customers and any given rate.

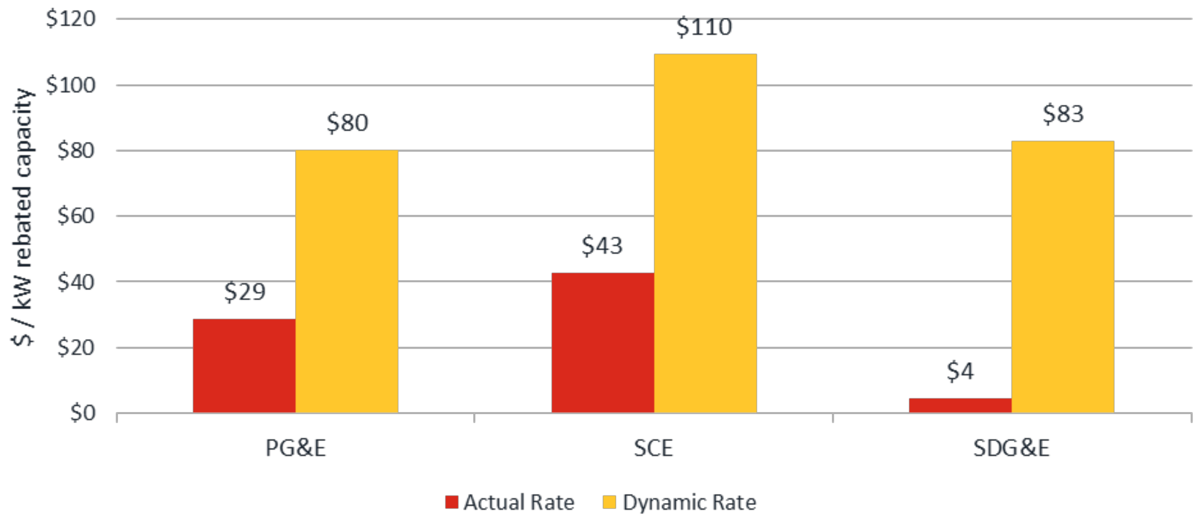
For each utility, we selected as the analogous option the most similar 2017 rate in our AES project sample. PG&E's proposed E19S rate with new TOU periods was matched with the base E19S rate, SCE's TOU-8-RTP was matched with all TOU-8 customers and SDG&E's GIR rate was matched with all ALTOU customers in our sample. This comparison is summarized in Table 5-11 below. Recall that we are simulating optimized dispatch for each customer – this analysis is not based on actual dispatch in 2017.

TABLE 5-11: DYNAMIC RATE AND BASE TOU RATE COMPARED FOR EACH UTILITY

	PG&E	SCE	SDG&E
Base TOU Rate	PGE E19S	SCE TOU-8 Option A SCE TOU-8 Option B SCE TOU-8 Option R	SDGE ALTOU
Dynamic Rate	PGE E19S proposed TOU	SCE TOU-8 Option RTP	SDGE GIR
Number of customers in sample	43	22	88

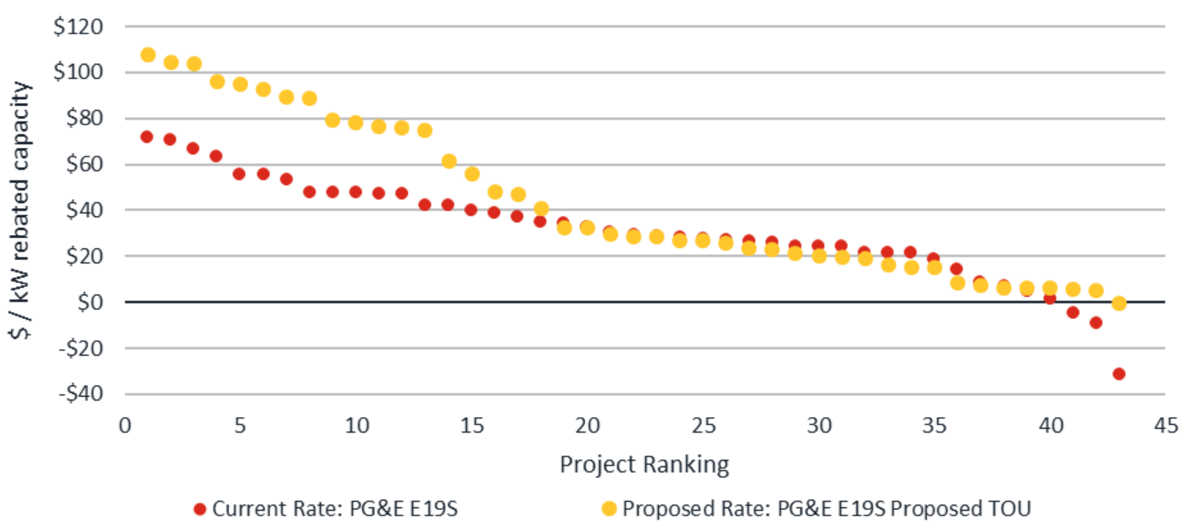
For each utility, the more dynamic rate significantly increases the system avoided costs from AES projects relative to 2017 rates. For PG&E, AES dispatched to maximize customer bill savings under the existing E19S rate provides system benefits of $28.82/kW of AES rebated capacity installed (Figure 5-24). Under E19S with the new proposed TOU periods, the avoided cost benefits are $80.16, an increase of $51.34/kW or 178%. For both SCE and SDG&E, the rate options modeled have hourly price signals and the benefits are even larger, over $60/kW of AES installed in both cases.

FIGURE 5-24: SYSTEM AVOIDED COSTS RESULTING FROM CUSTOMER DISPATCH APPROACH - DYNAMIC RATE COMPARED TO CUSTOMERS' ACTUAL RATE IN 2017 (N = 153)



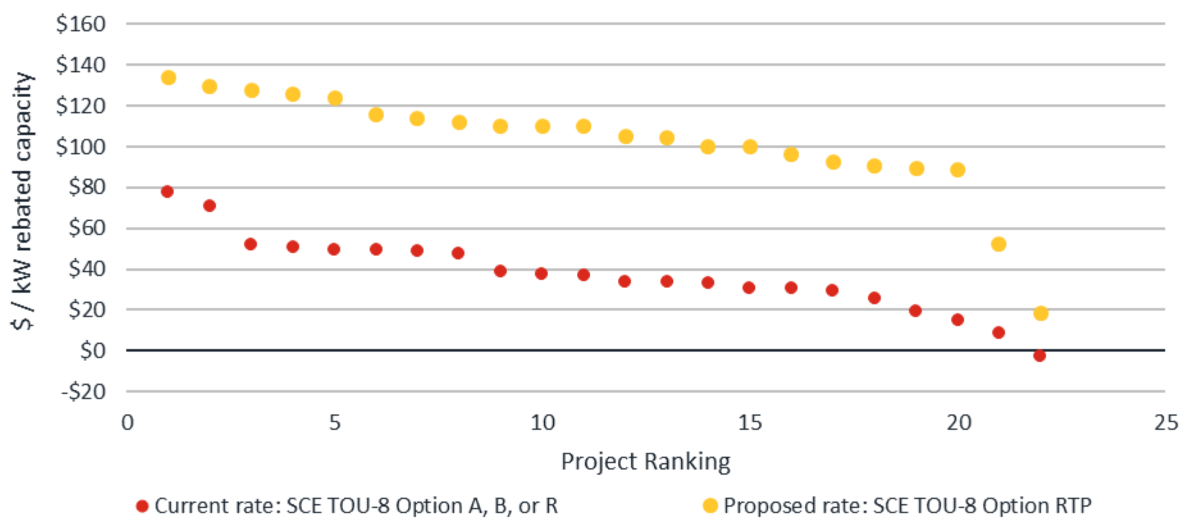
The system avoided costs from each AES system modeled are shown below in Figure 5-25 through Figure 5-27. Of the 44 PG&E AES customers modeled, 23 customers would provide higher system avoided costs if they dispatched their AES projects to minimize their bills under E19S with the proposed TOU periods versus the existing TOU periods. The remaining 21 customers would provide similar system avoided costs under the two rates.

FIGURE 5-25: $/KW SYSTEM AVOIDED COSTS RESULTING FROM CUSTOMER DISPATCH APPROACH, BY PROJECT, FOR PG&E (N = 43)



Optimizing bills against the hourly price signal of the SCE TOU-8 Option RTP, all 22 of the customers modeled would provide substantially more system avoided costs as compared to the TOU-8 rate.

FIGURE 5-26: $/KW SYSTEM AVOIDED COSTS RESULTING FROM CUSTOMER DISPATCH APPROACH, BY PROJECT, FOR SCE (N = 22)



For SDG&E, all 88 customers would provide substantially higher system avoided costs if minimizing bills under the GIR rate as compared to the ALTOU rate.

FIGURE 5-27: $/KW SYSTEM AVOIDED COSTS RESULTING FROM CUSTOMER DISPATCH APPROACH, BY PROJECT, FOR SDG&E (N = 88)

For this analysis we selected a single subgroup of customers for each utility on the same existing rate to compare to a new rate adopted or proposed by the respective utility. Thus, the results presented are in no way representative for all AES or all customers in each utility. Nevertheless, the results for these three specific customer groups clearly demonstrate significant potential for more dynamic rates to increase the grid benefits of customer owned AES.

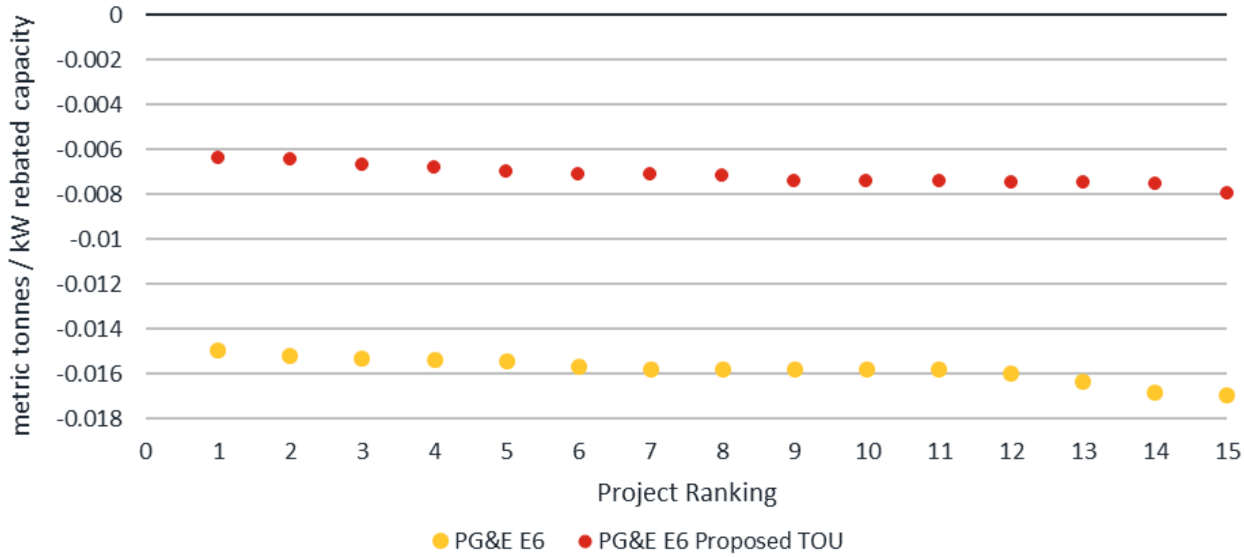
The PG&E analysis shows that the new proposed TOU periods do increase the avoided cost benefits provided to the utility grid with AES. Even the proposed TOU periods, however, leave significant potential benefits unrealized. Note that comparing the existing to proposed TOU period for PG&E showed benefits for approximately half of the 44 customers modeled. By comparison, the more dynamic rate options modeled for SCE and SDG&E showed significant additional benefits for nearly every customer modeled. The incremental benefits for SCE were $67/kW of AES installed and those for SDG&E were $79/kW, quite a bit more than the $51/kW average benefit shown for the PG&E rate with new TOU periods.

Modeling Residential AES projects on Alternative Tariffs

E3 received a sample of 28 residential AES projects (15 PG&E projects, 8 SCE projects and 5 SDG&E projects), all of which had 5 kW rebated capacity. The rate information received suggested that many of these customers were on flat rates in 2017. Several of the observed RTEs for these projects were very low (under 50%). Due to the small sample size, we restricted use of this residential data sample to the investigation of more "dynamic" rates, similar to that just described for nonresidential AES projects. For this purpose, we chose to use the 15 PG&E customers (our largest residential utility sample). We modeled these customers with rate E6 (residential TOU) under current TOU periods and using the proposed 2022 TOU periods (which have an on-peak definition of 4 – 9 pm). We used an RTE of 78% (the nonresidential sample average RTE). The results are shown in Figure 5-28 and Figure 5-29.

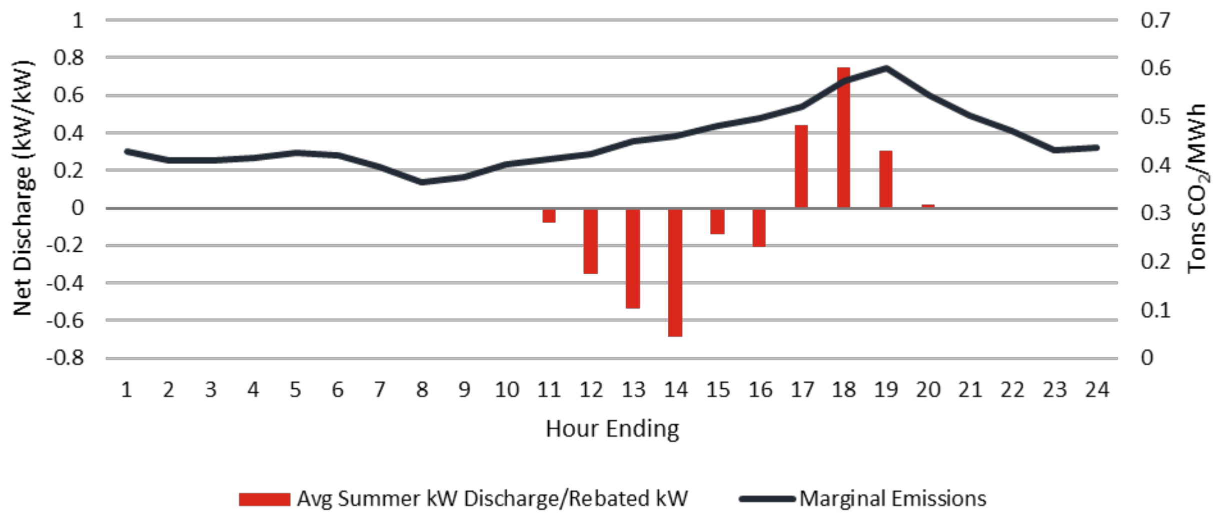
FIGURE 5-28: $/KW SYSTEM BENEFITS RESULTING FROM CUSTOMER DISPATCH APPROACH, BY PROJECT, FOR PG&E RESIDENTIAL CUSTOMERS (N = 15)

FIGURE 5-29: CO_2 EMISSIONS SAVINGS PER KW RESULTING FROM CUSTOMER DISPATCH APPROACH, BY PROJECT, FOR PG&E RESIDENTIAL CUSTOMERS (N = 15)



These residential results are consistent with our findings for the nonresidential dynamic rate analysis – use of rates that align more closely with system needs improves system avoided cost savings and carbon emissions for projects dispatched to optimize for customer bills. This alignment can be seen in the following chart, which overlays the marginal CO_2 emissions rate on the dispatch behavior for residential customers using the proposed E6 TOU periods. Since the proposed TOU definition includes a 4 – 9pm on-peak period, battery discharge occurs during these hours (residential rates do not include a demand charge). Note that while the hours with the highest CO_2 emissions rates do fall within this on-peak period, residential storage dispatched to minimize bills will also charge during some hours of relatively high emissions (e.g. hours ending 14 – 16).

FIGURE 5-30: PG&E RESIDENTIAL CUSTOMER AVERAGE NET SUMMER DISCHARGE PER REBATED KW AS COMPARED TO MARGINAL EMISSIONS RATE (N = 15)



6 INTEGRATED RESOURCE PLANNING

The analysis described thus far has examined the *actual* operation of AES projects in 2017 (Section 4), and what the *optimal* 2017 dispatch of AES would have looked like from different perspectives with perfect information (Section 5). This section considers the future, potential *long-term* contribution of SGIP AES projects for California's efforts to procure renewable generation and reduce greenhouse gas (GHG) emissions.

Section 5 takes a historical look at 2017 and quantifies the potential for AES to reduce system costs. The DER Avoided Cost approach described in that chapter assumes that energy storage reduces system costs on the margin, but that the resource portfolio and underlying grid operations remain unchanged. In contrast, this section looks forward to quantify the potential value of AES in providing capital investment and operational cost savings in the 2018 – 2030 timeframe as the penetration of renewable generation increases.

6.1 CALIFORNIA'S INTEGRATED RESOURCE PLANNING PROCEEDING

The task of integrated resource planning (IRP) in California is overseen by the CPUC to ensure that the electric sector is on track to help California reduce economy-wide GHG emissions 40% below 1990 levels by 2030. The more carbon-constrained the electricity system, the more value energy storage can provide in integrating intermittent renewable resources. To estimate the potential range of renewable integration value that storage could provide, E3 selected two IRP planning scenarios, each representing an electricity system that is built to achieve a different 2030 carbon level:

- A scenario that is built and deployed to achieve a statewide electricity sector target of 99 million metric tons of carbon by 2030 ('the 99 MMT' scenario). This scenario can be thought of as a California grid that is not at all constrained by a greenhouse gas target
- A scenario that is built and deployed to achieve a statewide electricity sector target of 30 million metric tons of carbon by 2030 ('the 30 MMT' scenario)

These scenarios are intended to provide low and high book-end values for energy storage in the CPUC IRP framework. The less constrained 99 MMT case will show a lower value for AES, given lower levels of renewable generation and associated curtailment and reserve requirements. Under the 30 MMT cap case, the electricity grid is more constrained, meaning that flexible solutions such as AES are more valuable.

Details of modeling assumptions for the IRP planning scenarios can be found at the CPUC's IRP proceeding webpage.[1]

6.2 E3'S RESOLVE MODEL

E3 has been supporting the CPUC throughout the IRP proceeding by using the RESOLVE model to investigate optimal resource portfolios to meet varying carbon emission targets under various planning scenarios. E3's Renewable Energy Solutions ("RESOLVE") tool is a power system operations and dispatch model that minimizes operational and investment costs over a defined time period. RESOLVE selects an optimal portfolio of renewable resources (such as wind, solar and geothermal), conventional generating resources (such as combined-cycle and simple-cycle natural gas generators), demand-side resources (such as energy efficiency and demand response) and renewable integration solutions (such as natural gas plant retrofits, flexible loads and energy storage). RESOLVE minimizes the sum of operating costs (fuel, O&M costs, and emissions), investment costs (the cost of developing new generation along with any associated transmission) and transmission wheeling costs over time. RESOLVE incorporates conventional power system constraints such as total delivered energy and generation resource adequacy, policy constraints such as renewable portfolio standards and greenhouse gas targets, scenario-specific constraints on the availability of specific resources and operational constraints that are based on a linearized version of the classic zonal unit commitment problem.

RESOLVE has particular strength in evaluating the value of system flexibility. In a flexibility-constrained system, the consequence of insufficient operational flexibility is curtailment of renewable energy production during time periods in which the system becomes constrained.[2] In a jurisdiction with a binding renewable energy target, however, this curtailment may jeopardize the utility's ability to comply with the renewable energy target. In such a system, a utility may need to procure enough renewables to produce more than their energy target in anticipation of curtailment events in order to ensure compliance with the RPS. This "renewable overbuild" carries with it additional costs to the system. In these systems, the value of an integration solution such as energy storage is in large part the renewable overbuild cost that can be avoided by using the solution to deliver a larger share of available renewable energy. Cost effectiveness for an integration solution under these conditions may be established when the avoided renewable overbuild cost exceeds the cost of the integration solution.

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[1] Available at: http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentB.RESOLVE_Inputs_Assumptions_2017-09-15.pdf

[2] Olson, A., R. Jones, E. Hart and J. Hargreaves, "Renewable Curtailment as a Power System Flexibility Resource," The Electricity Journal, Volume 27, Issue 9, November 2014, pages 49-61

The flexibility of RESOLVE to select lowest-cost portfolios of grid resources makes it easy to assess the value of an incremental resource, such as storage, that is added to the system. The difference in total costs between a RESOLVE run with and without AES shows the incremental value of energy storage. Sometimes, this value is realized as an avoided fixed cost. For example, an energy storage asset might defer the need to build additional capacity to meet peak demand. In other instances, the value can be attributed to avoided variable costs: solar generation, which has no variable cost, can offset the operational costs of running a conventional generator to meet load in the middle of the day. This RESOLVE modeling approach minimizing fixed and variable costs was used to determine the value of SGIP AES projects operating in 2017 relative to renewables integration. We assessed total system costs with and without SGIP AES. The difference can be taken as an approximation of the AES projects' long-term value in integrating a high renewables future.

6.3 MODELING SYSTEM VALUE FROM AES IN RESOLVE

The average daily system load and marginal costs for the two IRP Planning Scenarios used to quantify a high (30 MMT) and low (99 MMT) value for AES are shown below for 2018 (Figure 6-1) and 2030 (Figure 6-2). The daily load is identical for a given year between the planning scenarios. However, given the difference in grid conditions, they have different underlying marginal energy costs. These differences for 2018 and 2030 are displayed in Figure 6-1 and Figure 6-2 respectively. (Note: the marginal costs in 2018 are nearly identical between planning scenarios.)

FIGURE 6-1: AVERAGE HOURLY GROSS SYSTEM LOAD (MW) AND MARGINAL COST ($/MWH) BY PLANNING SCENARIO, 2018

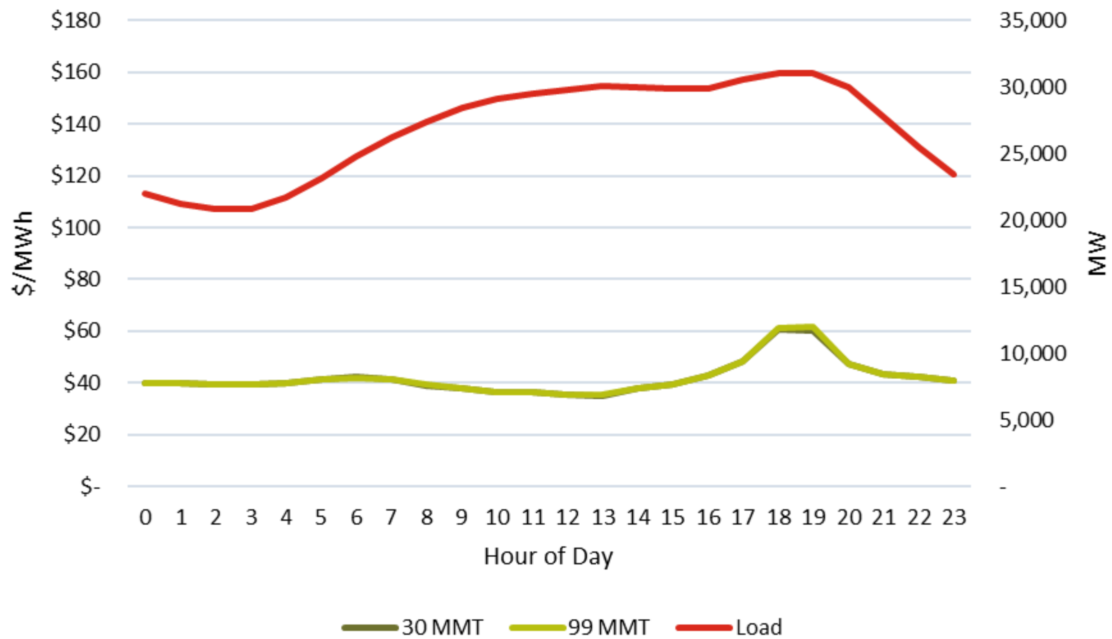
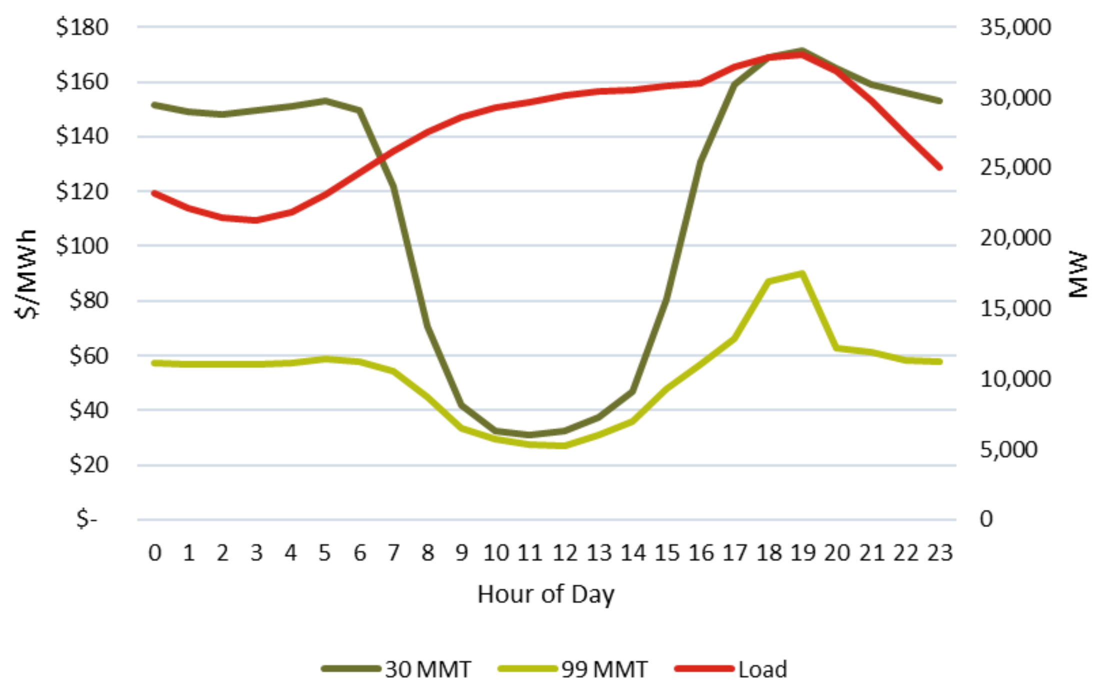


FIGURE 6-2: BASE CASE AVERAGE HOURLY GROSS SYSTEM LOAD (MW) AND MARGINAL COST ($/MWH) BY PLANNING SCENARIO, 2030



While we see a modest increase in the gross load profile between the two years, there is a dramatic difference in the net load shape and marginal cost of energy between 2018 and 2030, and between planning scenarios. This change is predominantly the result of deeper penetration of solar generation to meet increasingly stringent RPS and carbon demands. The stricter the greenhouse gas constraint, the larger the mid-day dip in energy prices, attributed to the ramping down of flexible energy solutions and the ramping up of solar. In addition to reducing the marginal cost of energy mid-day, this increase in solar capacity also makes for a steeper evening ramp, exacerbating the marginal cost of serving energy during the evening peak.

6.3.1 Modeling AES Use Cases

When evaluating an incremental resource's value to the grid, it is important to realistically depict the resource's operational capabilities and limitations, and the degree to which AES can be relied upon as a grid resource. Given the uncertainties in these variables for AES, a range of AES use cases were constructed. These are discussed in the following sections.

Low-Value Storage Use Case: AES as a Load Modifier

Under this use case, the system-level electricity demand is modified to reflect the incremental impact of SGIP AES projects operating in 2017. To implement this use case, the nonresidential projects in our sample were aggregated to provide an 8,760-hour profile of AES load (which is negative when storage is discharging in aggregate). This load profile was then scaled up to reflect the nonresidential AES population by the end of 2017. This provides the assumed "load modification" that can be attributed to AES projects.

Compared to the other use cases, this use case is considered the "low value" proposition because it provides RESOLVE with a static incremental resource. That is, RESOLVE cannot determine how to charge or discharge AES in this case – the storage dispatching is already provided to the model as a given. One can think of this use case as extending the status quo of 2017 AES dispatching into the future as a load modifier without regard to changing marginal energy prices.

Mid-Value AES Use Case: AES Dispatched to Minimize System Costs through 2030, Excluding Provision of Reserves

To approximate a mid-value case, we assume that AES will be dispatched in a moderately flexible manner for utility grid benefit, but without the ability to provide operating or contingency reserves. To create this mid-value use case, we assume AES can shift load on an hourly basis but does not provide reserves in CAISO ancillary service markets. A prior E3 study with Lawrence Berkeley National Lab (LBNL) for the

CPUC[3] on the potential value of advanced demand response resources describes the value that AES or flexible load can provide in load shifting (aka 'Shift') and load following and frequency regulation (aka 'Shimmy'). In this mid-value use case, AES is providing Shift but not Shimmy services for the grid.

High-Value AES Use Case: AES Dispatched to Minimize System Costs through 2030, Including Through Provision of Reserves

In the high-value use case, AES is providing both Shift and Shimmy services. The grid requirements for resources to provide operating reserves (frequency regulation and load following) as contingency reserves (spinning and non-spinning reserves) are derived from a detailed analysis of historical data and projections of renewable generation and loads. With AES permitted to provide reserves, the capital investment and operating costs for other resources to provide those services in RESOLVE are reduced.

To model this highest-value use case, we model SGIP AES capacity as a flexible resource that can be dispatched by grid operators. This storage could provide reserves, charge in the mid-day to minimize renewable curtailment, and discharge perfectly in the evening to reduce peak demand. Just as the load modification use case is a lower bound for renewable integration value, this use case serves as an upper bound. It assumes AES can participate in wholesale CAISO energy and ancillary service markets and be dispatched with perfect foresight and in a manner to minimize the *grid's* costs. This represents an entirely different paradigm for customer-owned BTM storage that currently prioritizes customer reliability and retail bill reduction.

Other Data Inputs

Two additional parameters that RESOLVE required for modeling AES were an overall round-trip efficiency and a duration capacity of the storage resource. The assumption used for round-trip efficiency was the aggregate round-trip efficiency of all the AES projects in the sample of nonresidential SGIP AES projects operating in 2017: 80% round-trip efficiency.

We used twice the SGIP rebated capacity as an upper estimate of the inverter capacity for the nonresidential SGIP population (129 MW) and assumed all AES projects have a one-hour duration. RESOLVE assumes a 5% discount rate for system costs.

[3] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698

6.4 RESULTS

6.4.1 Dispatch

Low Value: AES as Load Modifier

In the Low Value use case, in which nonresidential AES is modeled as a static load modifier, RESOLVE has no flexibility in operating AES projects. Instead, AES is modeled only by making a small shift to the gross load profiles, keeping the shape of the AES dispatch constant over time and changing only the underlying system load level. The AES dispatch as a load shown in Figure 6-3 for the 99 MMT planning scenario and Figure 6-4 for the 30 MMT planning scenario is the same for both cases. In these figures, the average net discharge is compared to the 2018 and 2030 marginal energy costs.

FIGURE 6-3: AVERAGE HOURLY STORAGE DISPATCH, LOW VALUE USE CASE, PLUS SYSTEM MARGINAL COSTS, 99 MMT PLANNING SCENARIO

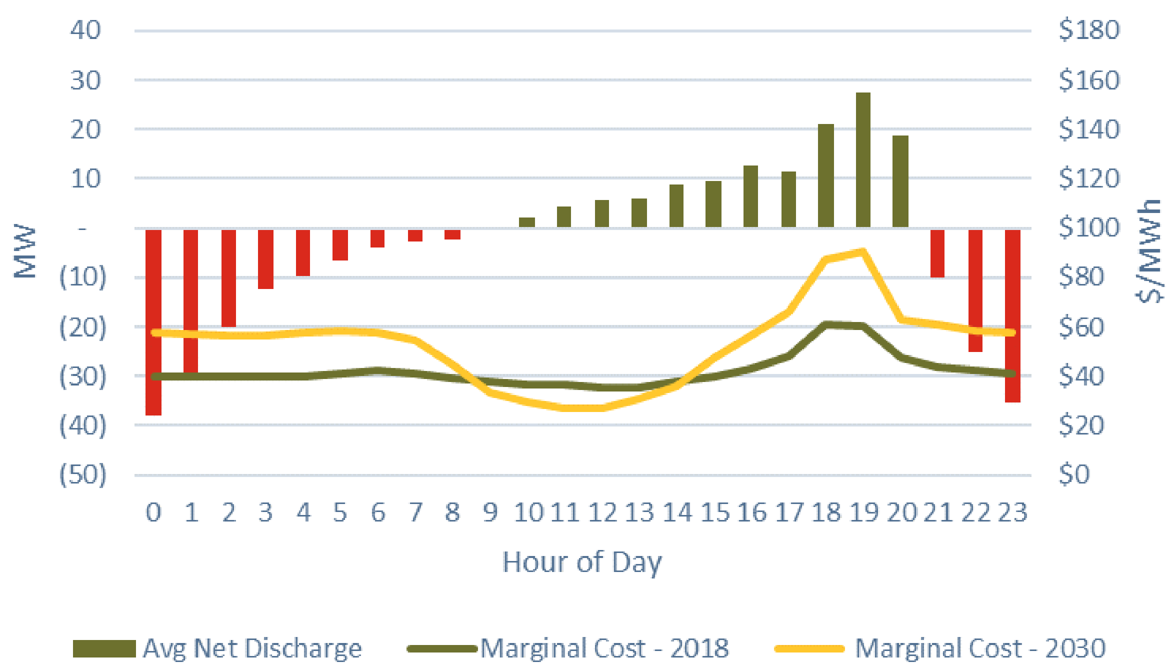
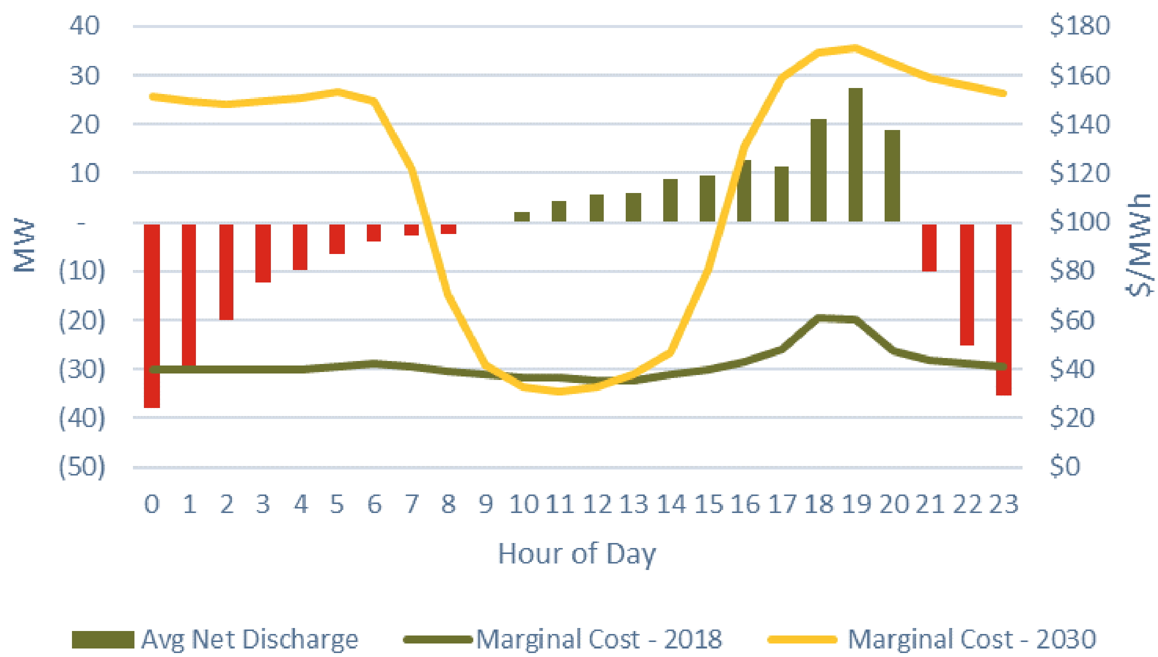


FIGURE 6-4: AVERAGE HOURLY STORAGE DISPATCH, LOW VALUE USE CASE, PLUS SYSTEM MARGINAL COSTS, 30 MMT PLANNING SCENARIO



AES dispatching aligns more favorably with the 2018 marginal cost shape than with the 2030 shape, since the dispatch of AES is not enabled to change over time. In 2030, the marginal cost of serving load in the morning is considerably more expensive than the cost at mid-day due to further adoption of both utility-scale and rooftop solar PV. Assuming incentives and retail rates will in fact change over time as California's electricity grid evolves, then this static use case can be thought of as a lower bound for the potential value of SGIP in a high-renewables system.

Mid-Value: AES Dispatched to Minimize Utility Costs, Excluding Provision of Reserves

The mid-value case shows the value for AES providing hourly load-shifting, but not operating or contingency reserves. Figure 6-5 and Figure 6-6 summarize AES dispatch in the Mid Value cases under the 99 MMT Planning Scenario. Figure 6-7 and Figure 6-8 provide similar findings for the 30 MMT Planning Scenario.

We see in both 2018 and more dramatically in 2030 that SGIP discharging is maximized in the evening hours, when electricity demand is at its highest and most expensive. Conversely, AES concentrates its charging in the early morning (in 2018) and mid-day to take advantage of zero marginal cost renewable generation. The result is a reduction in variable costs, the predominant source of value generated in the Mid Value use cases.

FIGURE 6-5: AVERAGE HOURLY AES DISPATCH, MID VALUE USE CASE, 99 MMT PLANNING SCENARIO, 2018

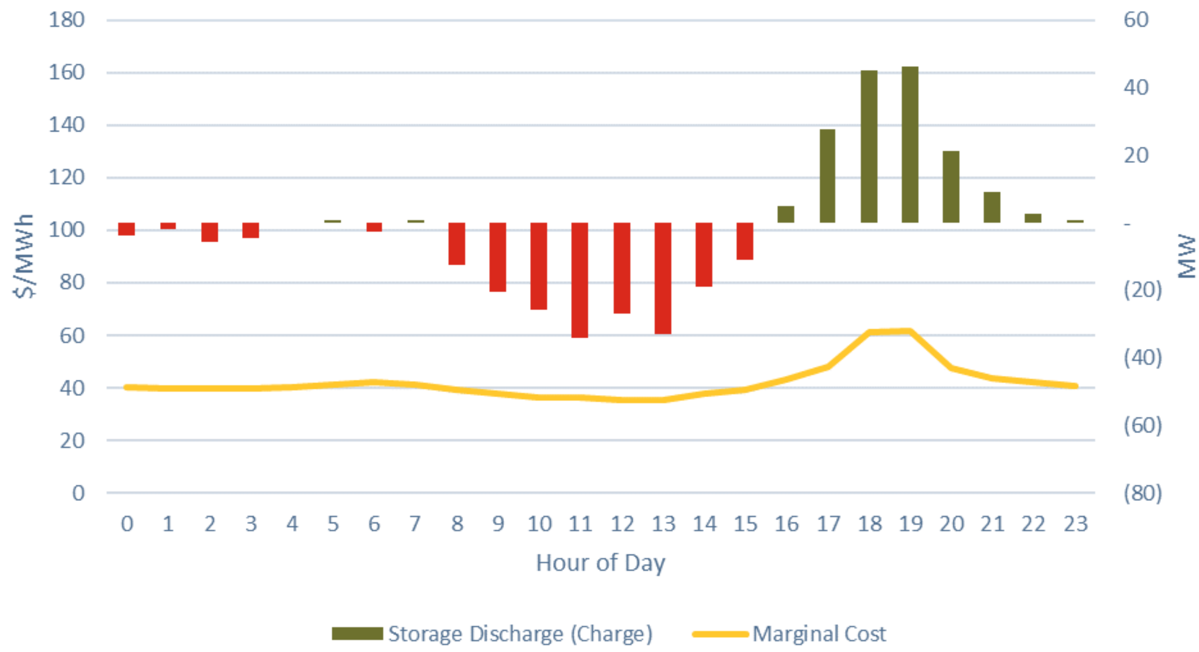


FIGURE 6-6: AVERAGE HOURLY AES DISPATCH, MID VALUE USE CASE, 99 MMT PLANNING SCENARIO, 2030

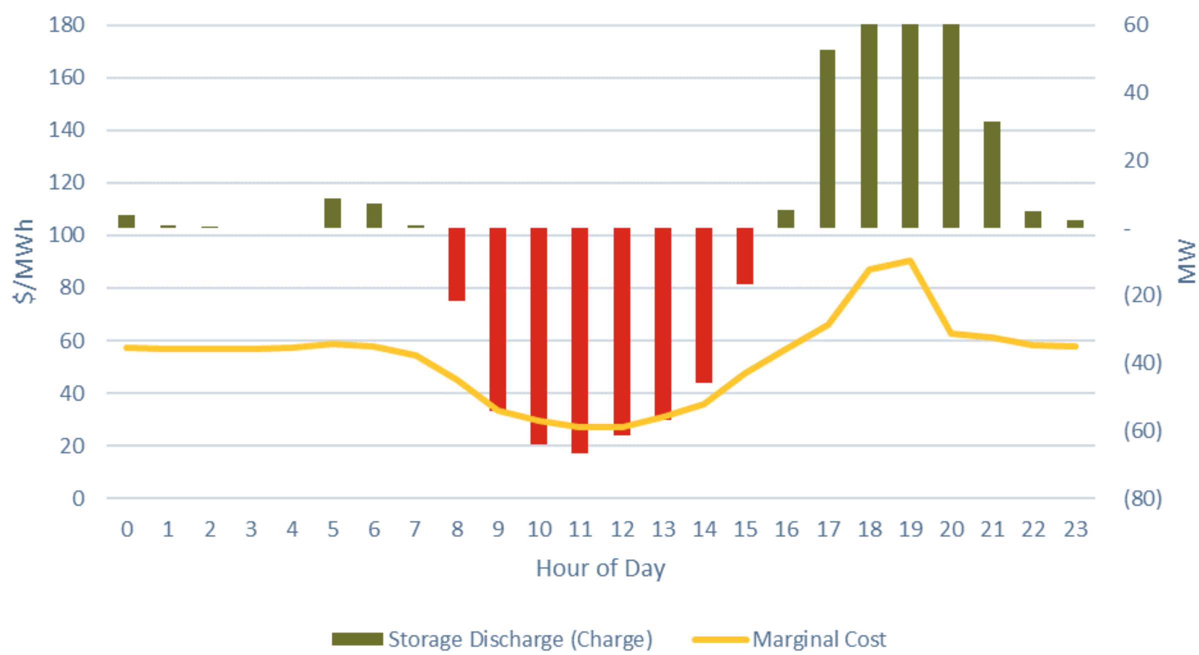


FIGURE 6-7: AVERAGE HOURLY AES DISPATCH, MID VALUE USE CASE, 30 MMT PLANNING SCENARIO, 2018

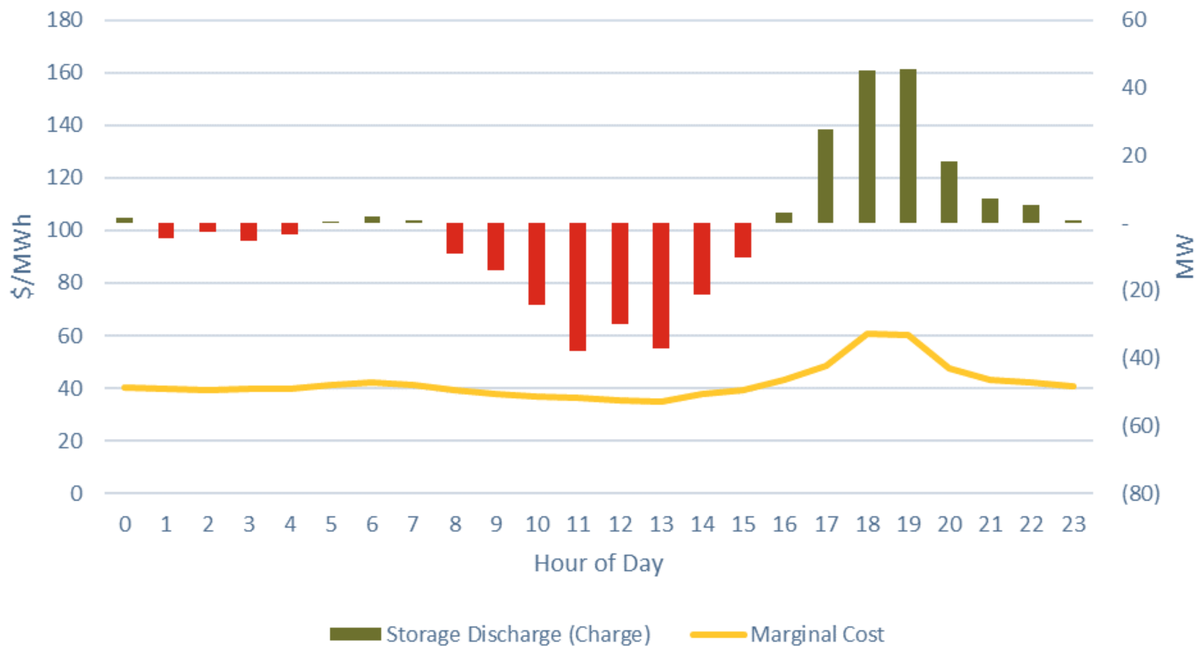
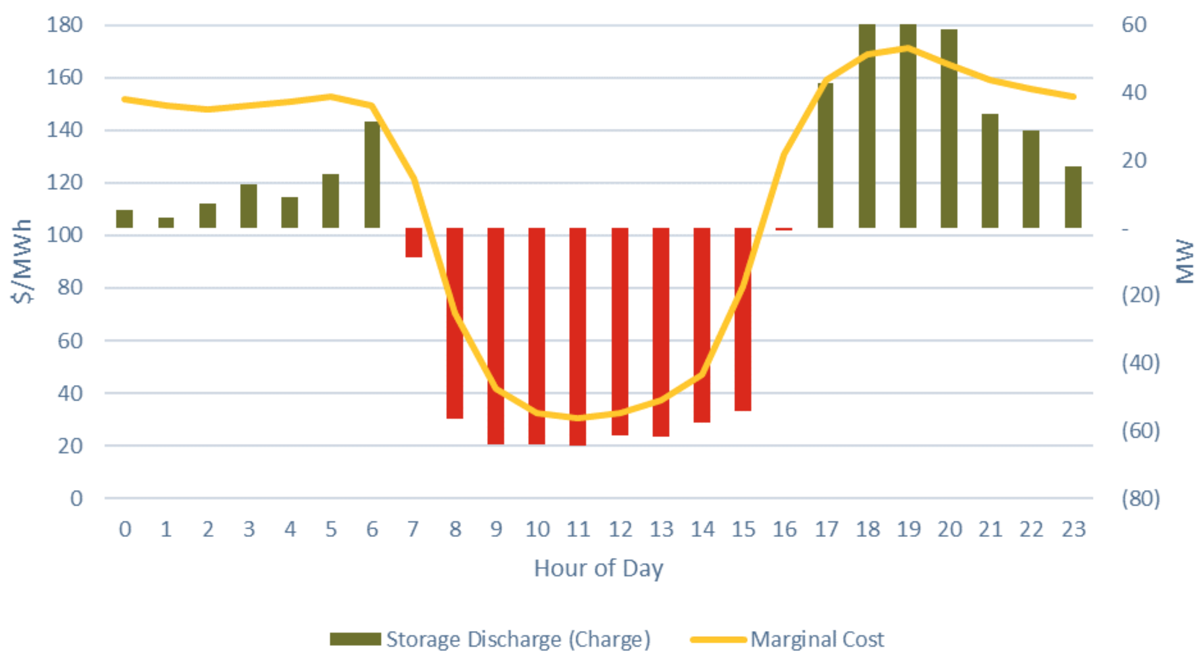


FIGURE 6-8: AVERAGE HOURLY AES DISPATCH, MID VALUE USE CASE, 30 MMT PLANNING SCENARIO, 2030



High Value: AES Dispatched to Minimize System Cost, Including by Providing Reserves

Recall that the High Value AES use case assumes that nonresidential SGIP AES can be dispatched optimally against changing grid costs *and* can provide reserves. Figure 6-9 and Figure 6-10 show the resulting AES dispatch for the High Value use case for the 99 MMT planning scenario; Figure 6-11 and Figure 6-12 for the 30 MMT planning scenario.

In these cases, the hourly dispatch of energy storage in 2018 for load-shifting is significantly reduced relative to the Mid Value use case. AES is instead providing more value in reserves, for which the charge and discharge are not shown. In the 30 MMT planning scenario, by 2030, load-shifting for ramping and avoided curtailment are providing significant value and the hourly dispatch for AES is much higher than in 2018. In the 99 MMT case, the ramping and avoided curtailment value do not increase and AES continues to provide the most value in reserves.

FIGURE 6-9: AVERAGE HOURLY AES DISPATCH, HIGH VALUE USE CASE, 99 MMT PLANNING SCENARIO, 2018

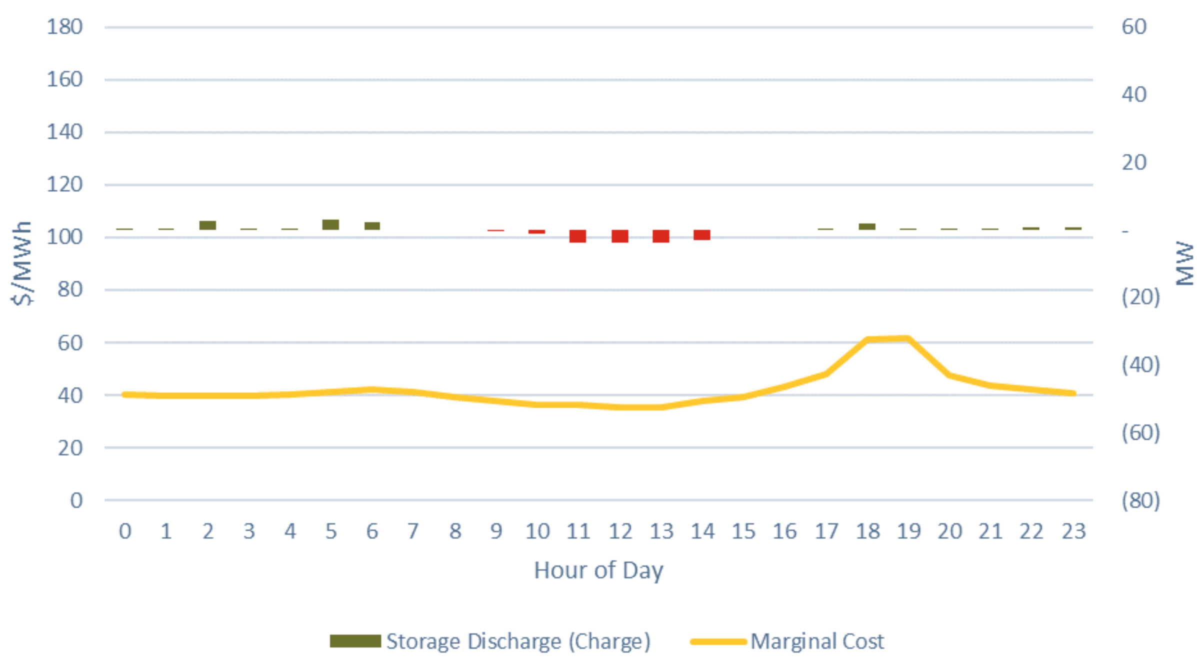


FIGURE 6-10: AVERAGE HOURLY AES DISPATCH, HIGH VALUE USE CASE, 99 MMT PLANNING SCENARIO, 2030

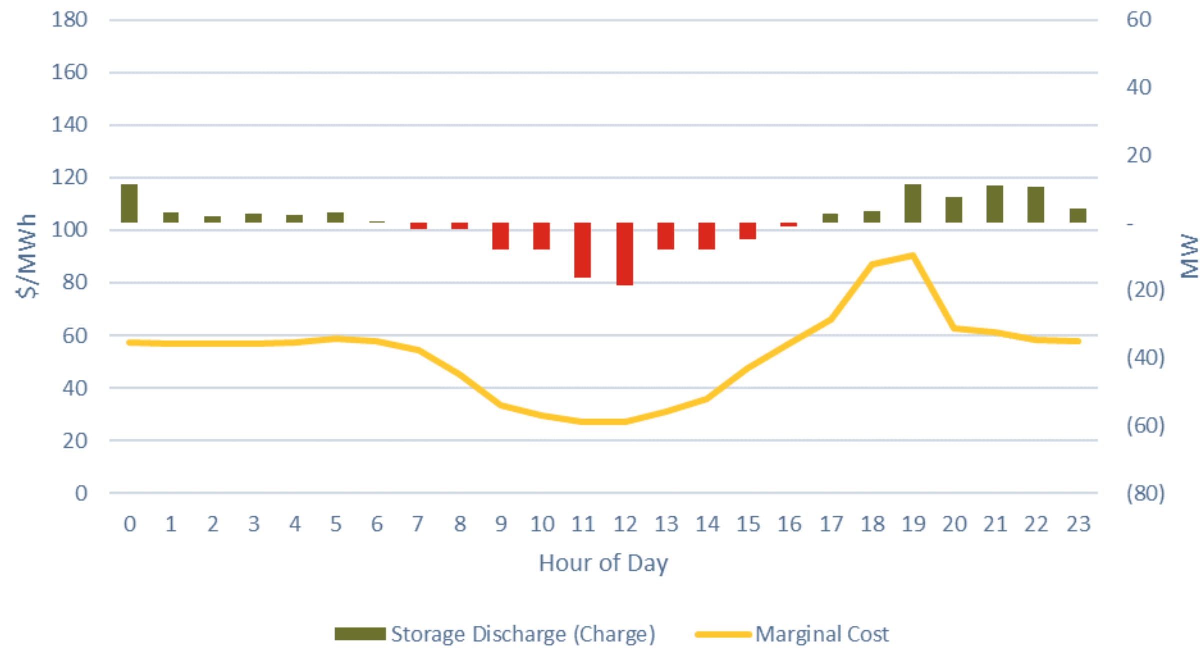


FIGURE 6-11: AVERAGE HOURLY AES DISPATCH, HIGH VALUE USE CASE, 30 MMT PLANNING SCENARIO, 2018

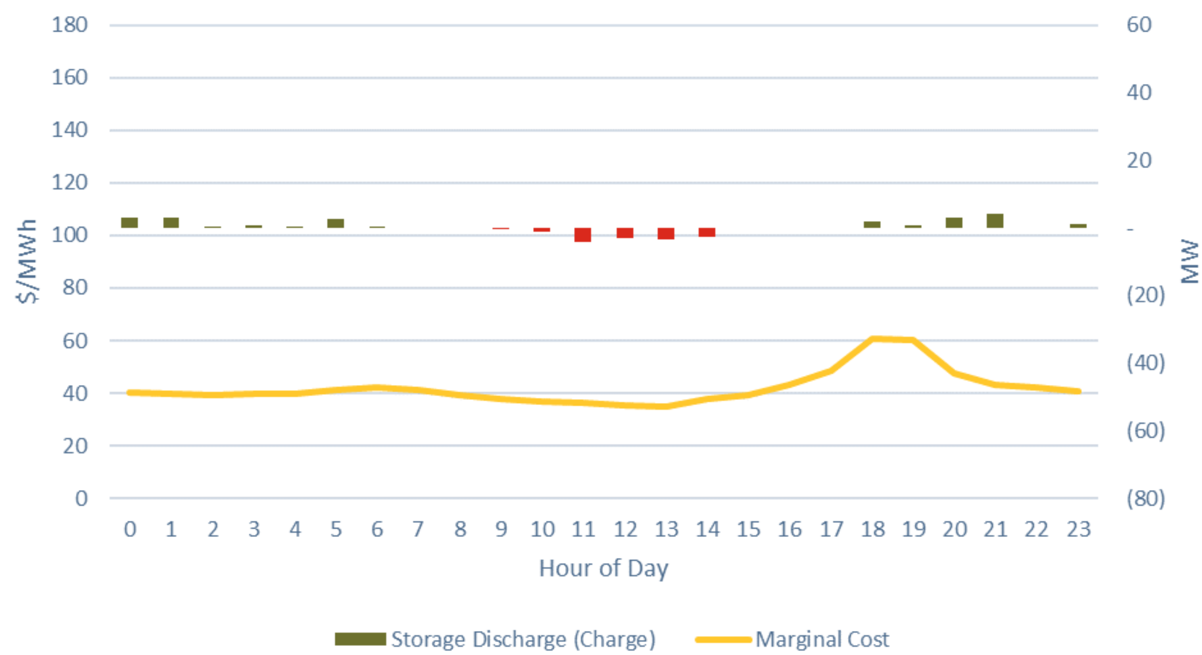
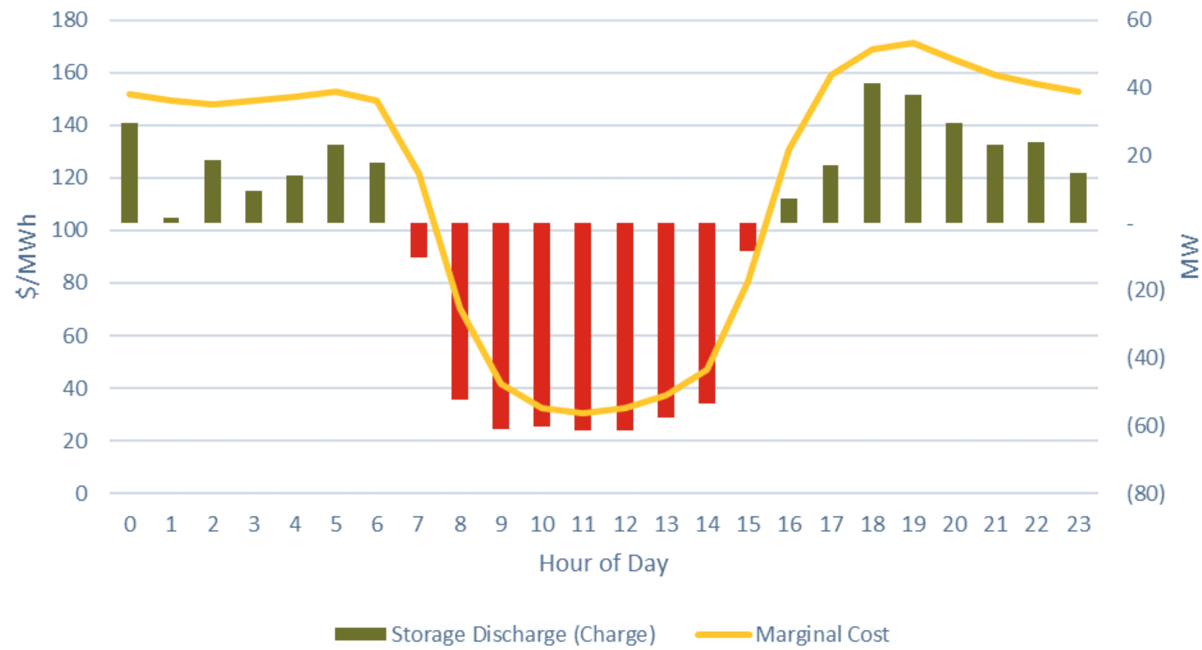


FIGURE 6-12: AVERAGE HOURLY AES DISPATCH, HIGH VALUE USE CASE, 30 MMT PLANNING SCENARIO, 2030



6.4.2 System Benefits

Table 6-1 shows the cumulative modeled system benefits for the 2018 – 2030 period from optimal dispatch of the nonresidential SGIP AES projects that were operating in 2017. Note that these results are not directly comparable to the DER Avoided Cost Model approach in Section 5 due to fundamental differences in the model approaches. Furthermore, the system capacity value in RESOLVE is lower than the value mandated by the CPUC for use in the DER Avoided Cost Model, and RESOLVE includes a distribution capacity value as a lower cost for DER relative to grid scale resources, but not as a benefit in the results.

In the Low Value use case, the observed cumulative savings actually go *down* as we move from the “low value” 99 MMT planning scenario to the “high value” 30 MMT planning scenario. This is because the Low Value use case models AES storage as a static load modifier, without regard to the different marginal costs in the two cases. The static load modifier shape is simply a better match for the 99 MMT planning scenario with lower incremental renewable penetration.

TABLE 6-1: CUMULATIVE SYSTEM BENEFITS FROM NONRESIDENTIAL SGIP AES PROJECTS THAT WERE IN OPERATION DURING 2017, NPV 2017$ MILLION, 2018 - 2030

AES Use Case	IRP Planning Scenario	
	99 MMT	30 MMT
Low Value	($0.09)	($1.59)
Mid Value	$15.08	$26.38
High Value	$16.87	$32.41

We find that AES Use Case is a larger driver of savings (and costs) than planning scenario: the value of AES depends more on how storage is utilized than which system costs California faces in the future. As with the DER Avoided Cost Approach, AES dispatched for customer benefit and treated as a load modifier increases total system costs, though only slightly, in both Planning Scenarios. In the Mid-Value use case, NPV benefits from 2018 to 2030 range from $15.1 million to $26.4 million, predominantly in variable operating cost savings. Cumulative savings are highest in the High-Value use case, ranging from $16.9 million to $32.4 million.

As with the DER Avoided Cost Model approach, these results show that significant value is left on the table if AES is not available to be dispatched by grid operators for system-level benefits. There is substantial value to be tapped into if storage operations can synchronize with grid operations as a whole, and that value is further increased if storage can be relied upon for providing reserves.

The sections below split this cumulative benefit into fixed cost, variable cost and avoided curtailment components.

Fixed Cost Savings

Table 6-2 shows the fixed cost savings achievable in the 2018 – 2030 period quantified in RESOLVE for AES.

TABLE 6-2: AVOIDED FIXED SYSTEM COSTS FROM NONRESIDENTIAL SGIP AES PROJECTS OPERATING IN 2017, NPV 2017$ MILLION, 2018 - 2030

AES Use Case	IRP Planning Scenario	
	99 MMT	30 MMT
Low Value	($0.06)	($1.33)
Mid Value	($0.81)	$5.55
High Value	$4.01	$19.06

In the 99 MMT planning scenario, only lithium ion storage and solar builds are impacted by the dispatch of SGIP AES. In the 30 MMT, pumped hydro build is also slight reduced. Table 6-3 and Table 6-4 summarize the differences *in capacity* of lithium ion storage and solar, respectively, selected by the RESOLVE model across all use cases and planning scenarios.

TABLE 6-3: CHANGE IN TOTAL LITHIUM ION BATTERY CAPACITY (MW) RESULTING FROM AES, 2018-2030

Use Case	99 MMT	30 MMT
Low Value Case	(0.44)	(1.98)
Mid Value Case	(11.88)	(18.20)
High Value Case	(51.08)	(1.68)

TABLE 6-4: CHANGE IN TOTAL SOLAR CAPACITY (MW) RESULTING FROM AES, 2018-2030

Use Case	99 MMT	30 MMT
Low Value Case	0.23	4.79
Mid Value Case	4.12	0.53
High Value Case	(1.57)	4.81

With RPS compliance serving as the primary binding constraint in modeling California's future electricity grid, RESOLVE optimizes the trade-offs between renewable overbuild (which increases curtailment) and integration resources, namely storage. In the Low Value use case, load is slightly reduced in the middle of the day, reducing the amount of energy that can be delivered from renewable resources. RESOLVE elects to slightly increase the amount of solar build to compensate for this. In the Mid-Value Case, SGIP storage displaces generic lithium ion storage that would otherwise need to be installed to move load from evening and nighttime hours into the middle of the day. However, because SGIP storage (with a round-trip efficiency of 80%) is less efficient than the generic lithium ion counterpart (with a round-trip efficiency of about 85%), this difference is met with some additional solar build. In the High Value Case, SGIP storage is used to provide system-level reserves, thus freeing up other, more efficient, generic lithium ion batteries to move load. In the 99 MMT case, this translates directly into the avoided cost of building more lithium ion storage, and a large reduction in lithium build is observed, along with a small reduction in solar build. The reduction in lithium ion storage in the 30 MMT case is more modest, as most of that storage is still cost effective in helping the carbon-constrained grid meet its emission requirements. Instead, the added flexibility of AES storage enables more solar, almost 5 MW, to be integrated into the system with less curtailment and a lower levelized cost.

Variable Cost Savings

As load varies over the course of days, seasons and years, different mixes of generation resources are used to meet it. These different mixes produce varying average and marginal costs. As such, variable cost savings are realized when load can effectively be served with a lower variable cost resource, whether by moving load to a point in time when a lower cost mix of generators is available to serve load, or by changing the mix available at a given time to produce a lower average cost. Table 6-5 shows the variable cost savings achievable in the 2018 – 2030 period by optimally-dispatched nonresidential SGIP AES.

TABLE 6-5: AVOIDED VARIABLE SYSTEM COSTS FROM NONRESIDENTIAL SGIP AES PROJECTS OPERATING IN 2017, NPV 2017$ MILLION, 2018 - 2030

	IRP Planning Scenario	
AES Use Case	**99 MMT**	**30 MMT**
Low Value	($0.03)	($0.26)
Mid Value	$15.89	$20.83
High Value	$12.86	$13.35

The shape of hourly energy demand and marginal energy cost in our two bookend years are fundamental to interpreting the impact that AES might have on renewable integration variable costs across the above use cases. Recall that the hourly marginal costs change significantly with increasing renewable penetration over time, as well as between our two emissions cap scenarios.

Avoided Curtailment

Though RESOLVE's objective function seeks to minimize the costs of operating a high renewables grid in dollar terms, it can be useful to frame the results of different scenarios through another metric, namely curtailment. The system-wide loads and thus RPS-compliance obligations are the same for a given Planning Scenario: that is, each scenario is constrained to *deliver* the same amount of renewable energy to meet RPS policy. However, the amount of renewable energy that must be procured and subsequently curtailed varies by Planning Scenario and Use Case.

TABLE 6-6: POTENTIAL CUMULATIVE AVOIDED CURTAILMENT FROM NONRESIDENTIAL SGIP AES, BY PLANNING SCENARIO AND AES USE CASE (MWH), 2018 - 2030

	IRP Planning Scenario	
AES Use Case:	**99 MMT**	**30 MMT**
Low Value Case	617	(6,033)
Mid Value Case	(70,979)	(33,053)
High Value Case	(80,347)	(111,912)

Unsurprisingly, the Low Value Case shows a relatively small curtailment benefit. More significant is the reduction in curtailment resulting from the High Value AES use case: curtailment falls from a total of 16.92 million MWh under the 30 MMT planning scenario to 16.80 million MWh. This reduced curtailment is the result of storage being able to move load from the evening and night time into the middle of the day to make use of as much solar production as possible, enabling less costly compliance with both the RPS and CO_2 limit.

6.5 SUMMARY OF INTEGRATED RESOURCE PLANNING VALUE

Section 5 shows that dispatching AES for system benefits rather than retail bill reduction provides significantly higher system cost benefits for utility ratepayers. This section shows that from a CPUC IRP perspective, AES dispatched for system benefits also provides much more value than BTM storage that is treated as a load modifier and not visible or dispatchable to system operators.[4] Load shifting (Shift) without reserves provides significant net present value of $15 and $23 million in the 99 MMT and 30 MMT planning scenarios respectively. Only under the 30 MMT case does modeling AES as also providing operating and contingency reserves (Shimmy) in the High Value case add significant additional net present value ($6 million) over the Mid Value Case. Challenges remain in enabling BTM AES to respond to grid needs through dynamic rates, utility programs or direct participation in CAISO energy and ancillary service markets, but significant value can be realized by doing so.

[4] One caveat is that the low value, load modifier case would presumably have a higher value than shown here if retail rates evolve over time to match system avoided costs. This would not change the larger conclusion that AES that is dispatchable by system operators would have a significantly higher value.

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

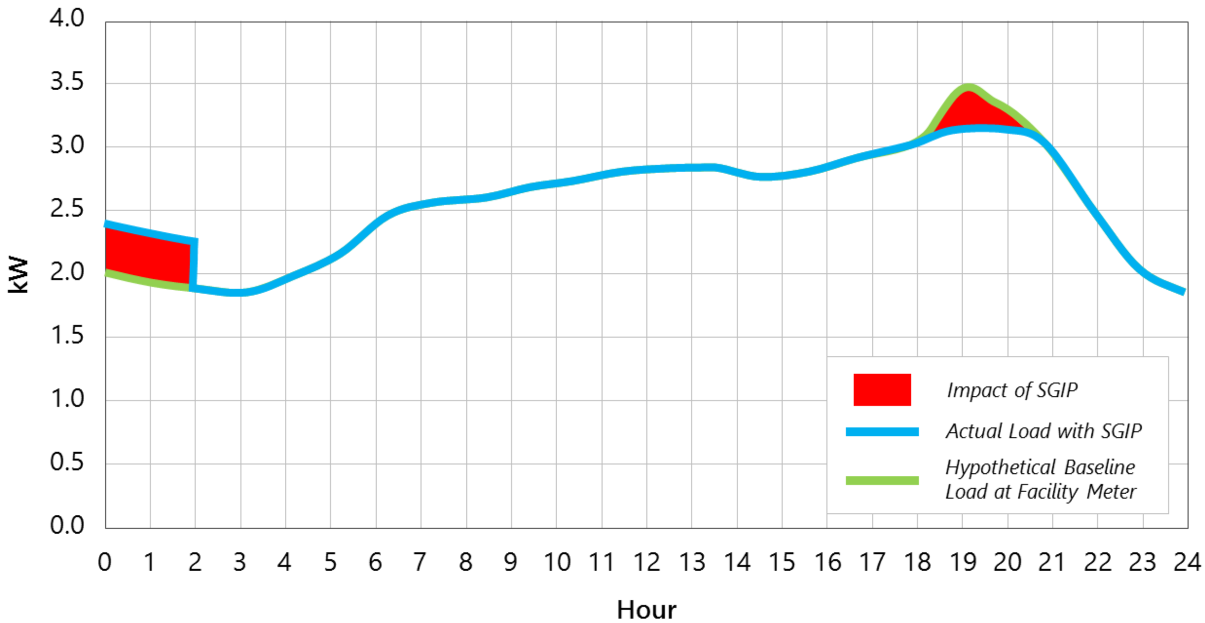
Scenario #1 applies to SGIP AES projects that are installed at facilities absent any additional on-site generation sources such as PV. Table A-1 summarizes the baseline and SGIP conditions in Scenario #1.

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

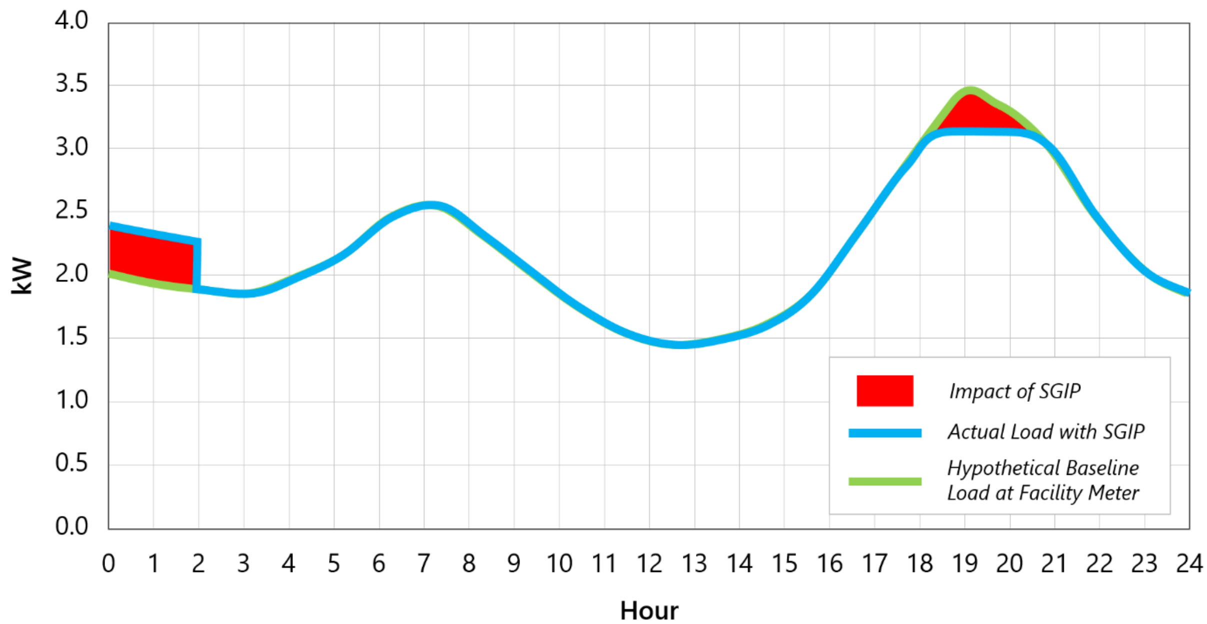
Scenario #2 applies to SGIP AES projects that are installed at facilities paired with on-site PV. The on-site PV in Scenario #2 is not attributed to SGIP meaning that the program did not influence its installation. Table A-2 summarizes the baseline and SGIP conditions in Scenario #2.

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

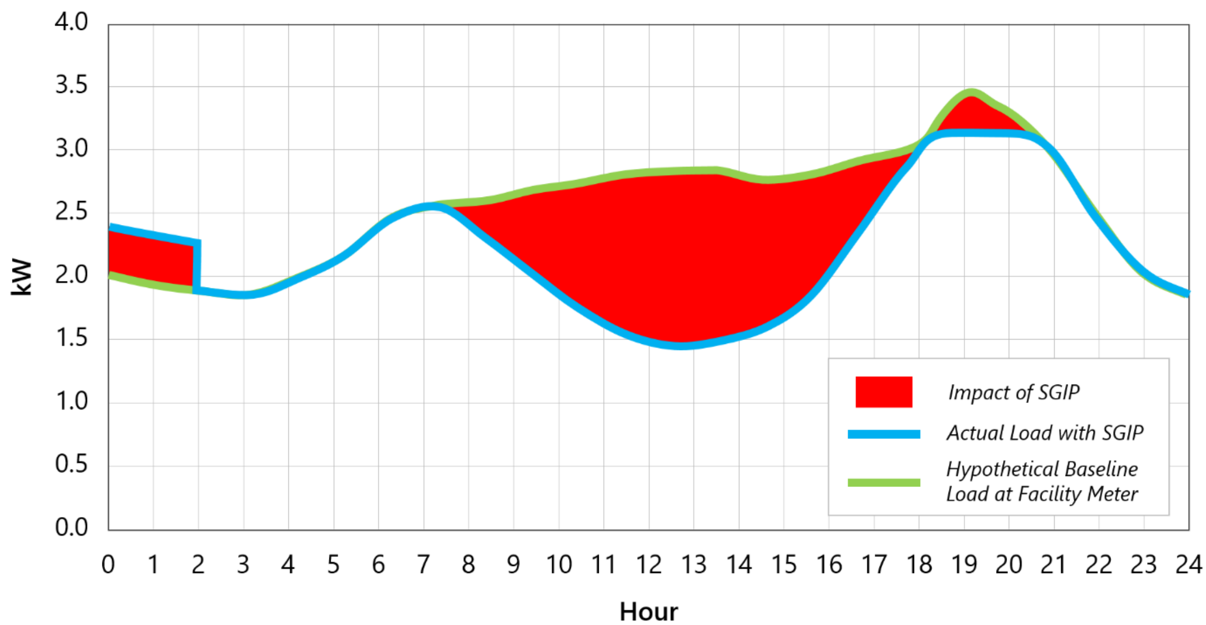
Scenario #3 applies to SGIP AES projects that are installed at facilities paired with on-site PV. The on-site PV in Scenario #3 is attributed to SGIP meaning that the program influenced its installation. Table A-3 summarizes the baseline and SGIP conditions in Scenario #3.

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

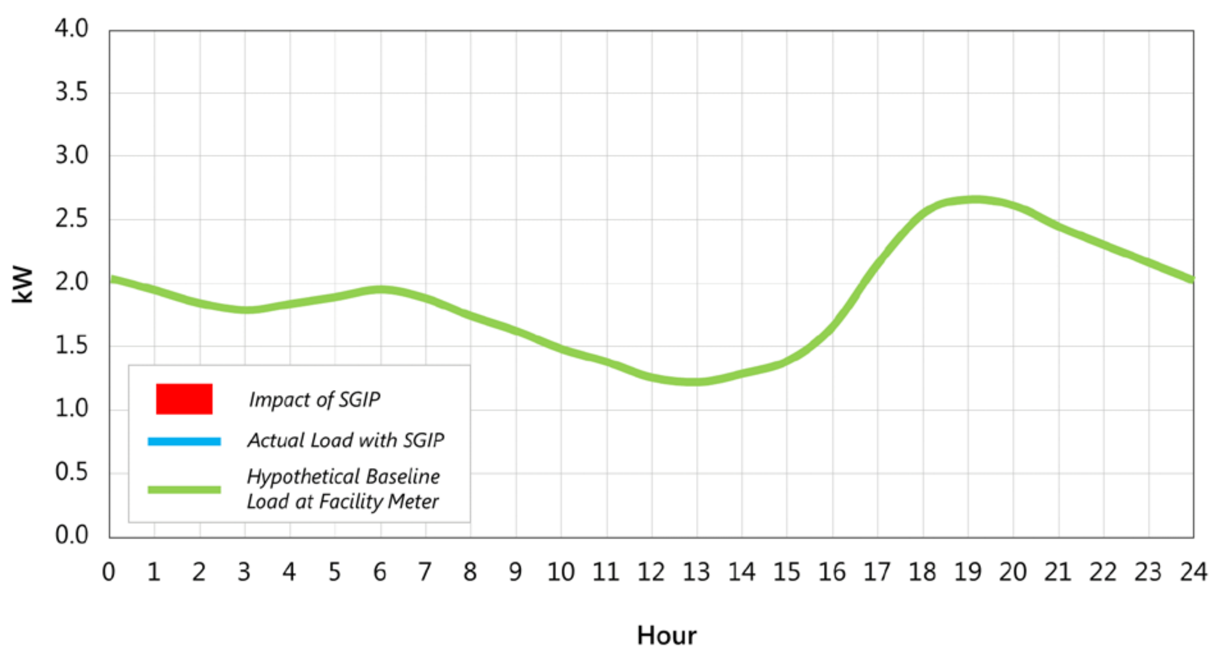


Figure A-5 reflects actual SGIP conditions, where AES is charging from renewables and then discharging in the evening. In the evening, during discharge, grid power levels for the customer are lowered. In the middle of the day, during charging from renewables, grid power levels for the customer are higher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

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

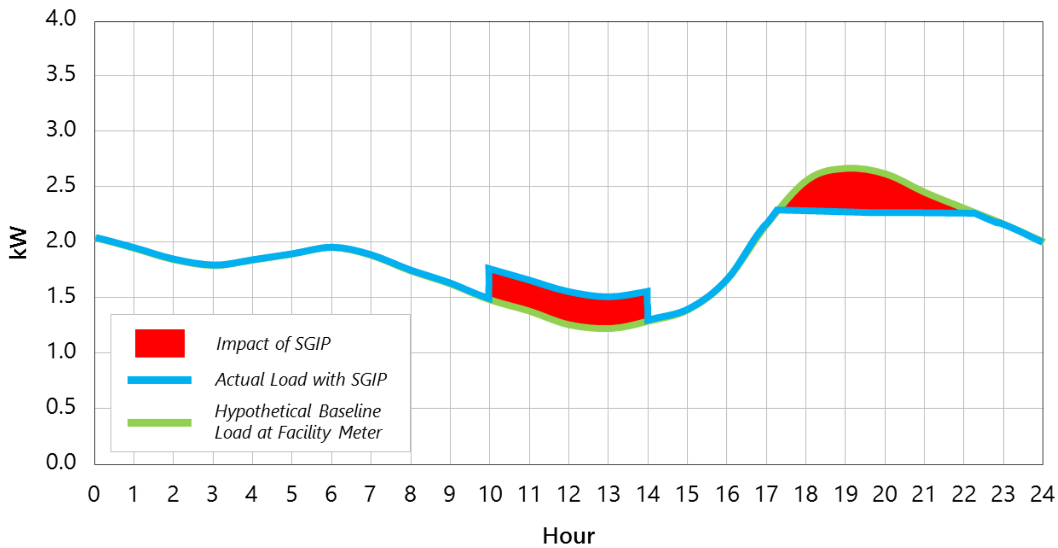
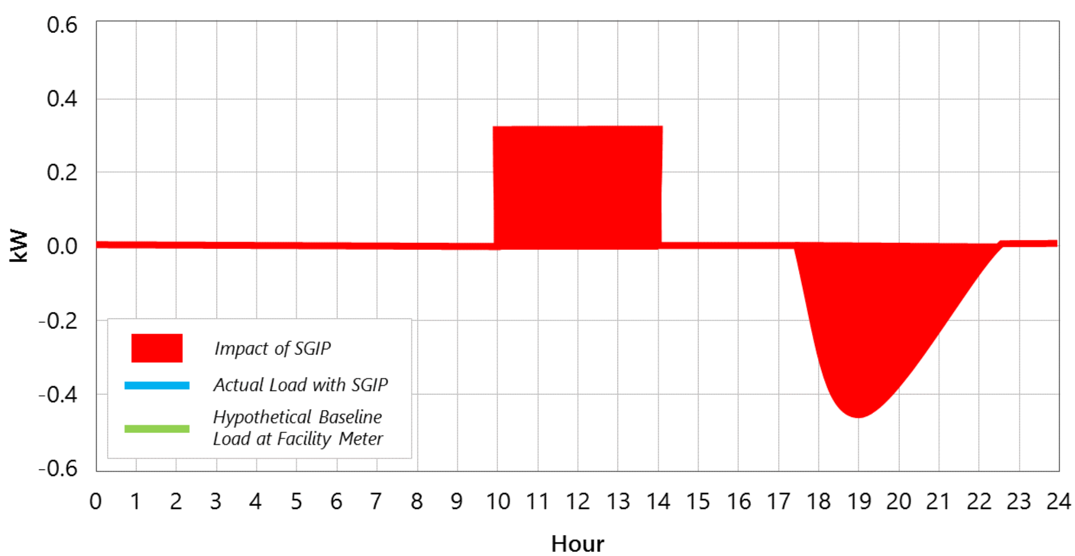


Figure A-6 summarizes the SGIP impact of AES projects in Scenario #2 charging from renewables. Most notably, program impacts are not influenced by PV in any way. PV generation only influences SGIP impacts in Scenario #3 where the SGIP influences the installation of PV.

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:

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

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

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

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

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:

$$sgipPV_{ih} = basePV_{ih} = 0 \quad \text{Eqn. 6}$$

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

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

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.

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	6,900

In addition to this base case methodology, E3 also ran a sensitivity that bounded heat rates using data compiled from the U.S. EPA's latest eGRID data for California. For this sensitivity, we used the 15th and 85th percentiles of gas plant heat rates from this source as emission rate bounds. These are shown in Table A-5.

TABLE A-5: BOUNDS ON ELECTRIC SECTOR CARBON EMISSIONS USING EGRID DATA

Baseline	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	12,503	5,641

For both the base case and sensitivity, if the implied heat rate is calculated to be at or below zero, it is then assumed that the system is in a period of overgeneration and therefore the marginal emission factor is correspondingly zero as well. Furthermore, beginning in the summer of 2016, the CAISO began publishing daily curtailment reports, providing the scope (system or local), timing and extent (in MW and MWh) of curtailment events. This data was used as a prevailing indicator for curtailment events. That is, in time increments identified by the CAISO as containing a system-level curtailment event, a marginal emissions rate of 0 tons/MWh was assumed. Otherwise, the market-based approach discussed above was used.

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 2017 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 2017. 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	100	100	96	91		
	Nonresidential	Y	42	42	42	37	42	42
	Residential	N	139	133	167	163		
	All		**281**	**275**	**305**	**291**	**42**	**42**
SCE	Nonresidential	N	101	78	71	63		
	Nonresidential	Y	52	46	50	48	52	52
	Residential	N	139	129	131	127		
	All		**292**	**253**	**252**	**238**	**52**	**52**
CSE	Nonresidential	N	74	72	72	69		
	Nonresidential	Y	49	48	49	47	49	49
	Residential	N	94	86	87	83		
	All		**217**	**206**	**208**	**199**	**49**	**49**
SCG	Nonresidential	N	1	1	2	2		
	All		**1**	**1**	**2**	**2**		

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:

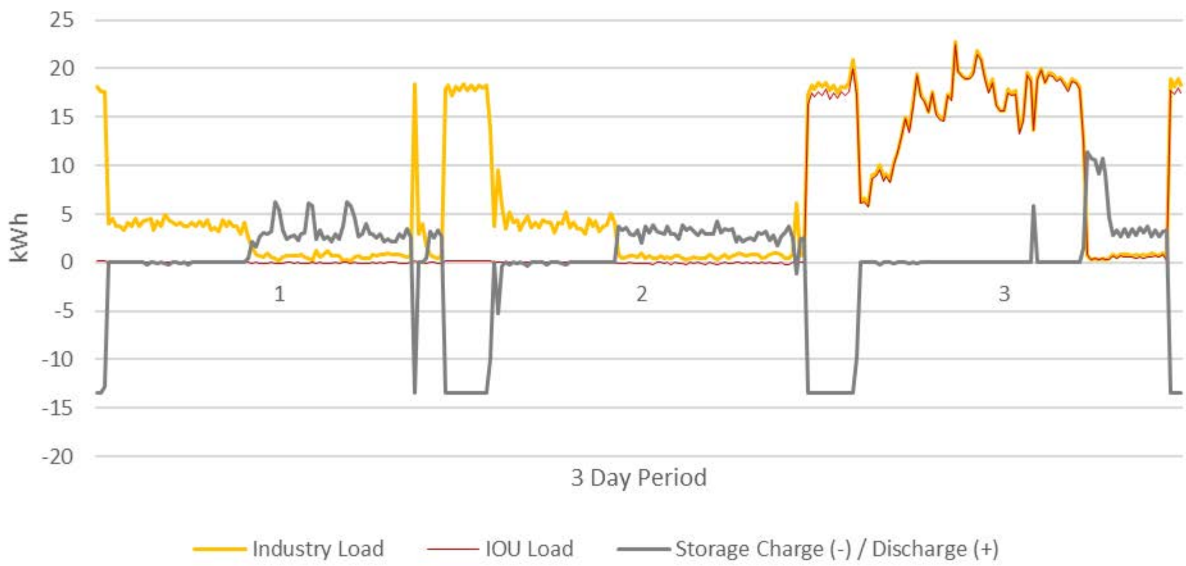
- Interval battery data from developers were verified against interval battery data from Itron meters.

- 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 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).

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.

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

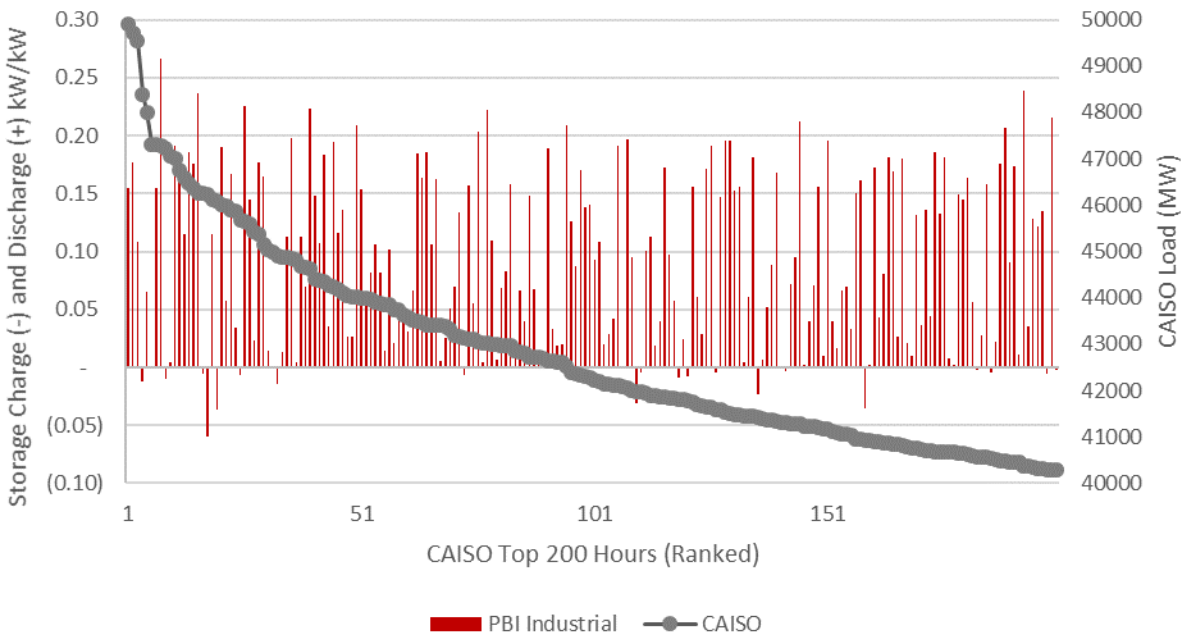


FIGURE C-2: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI OFFICE)

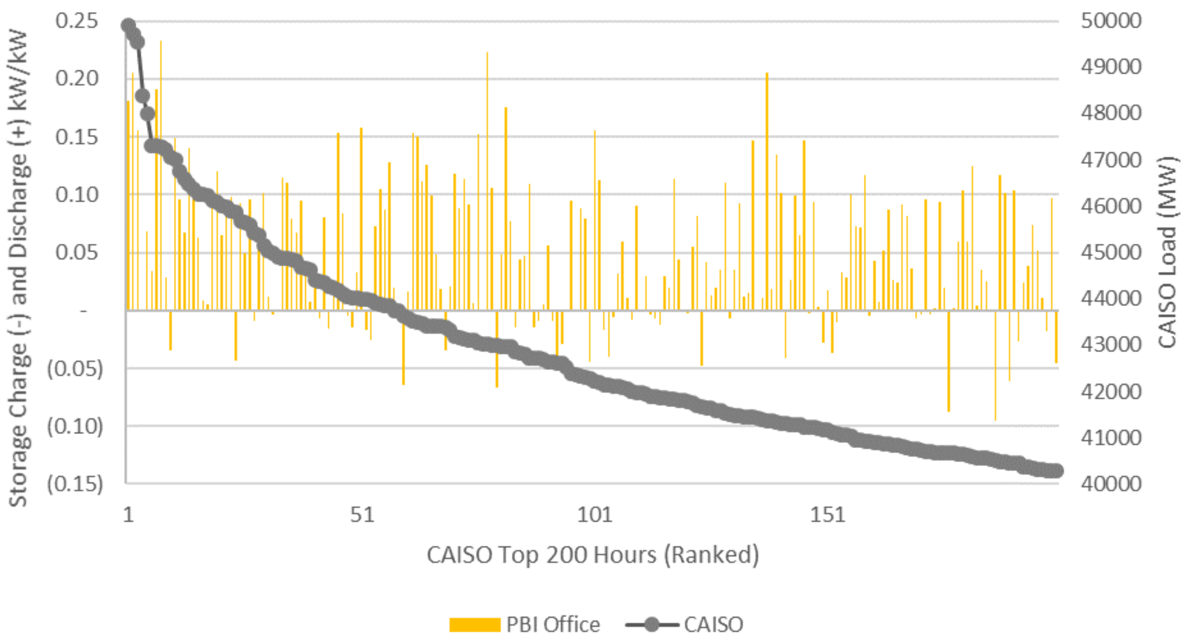


FIGURE C-3: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI OTHER)

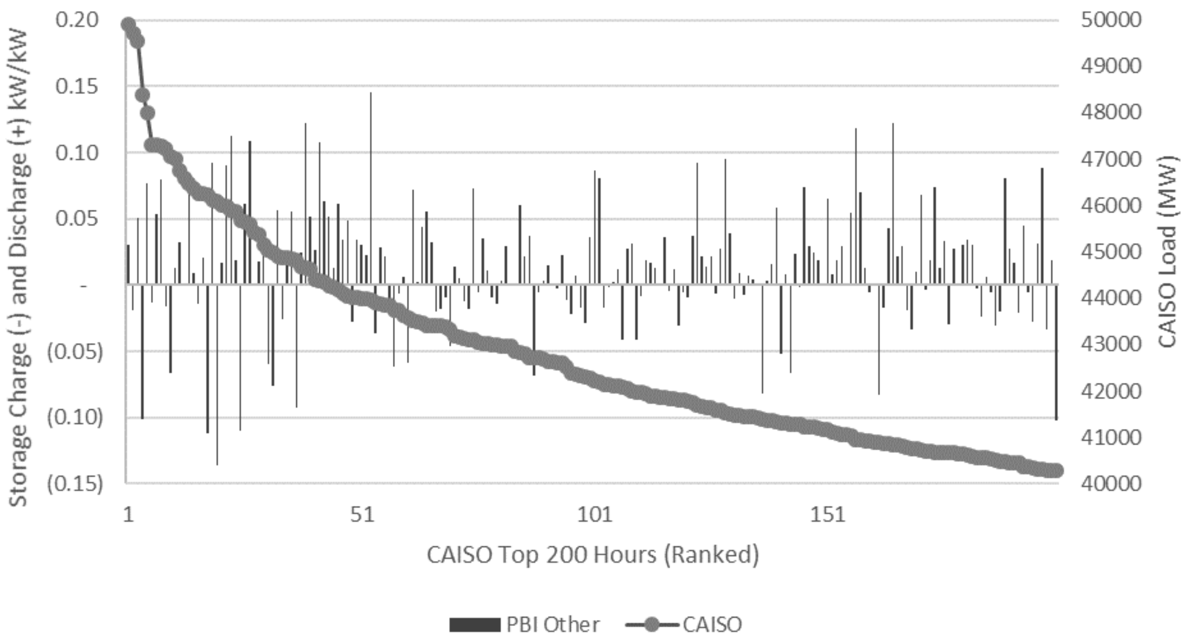


FIGURE C-4: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI RETAIL)

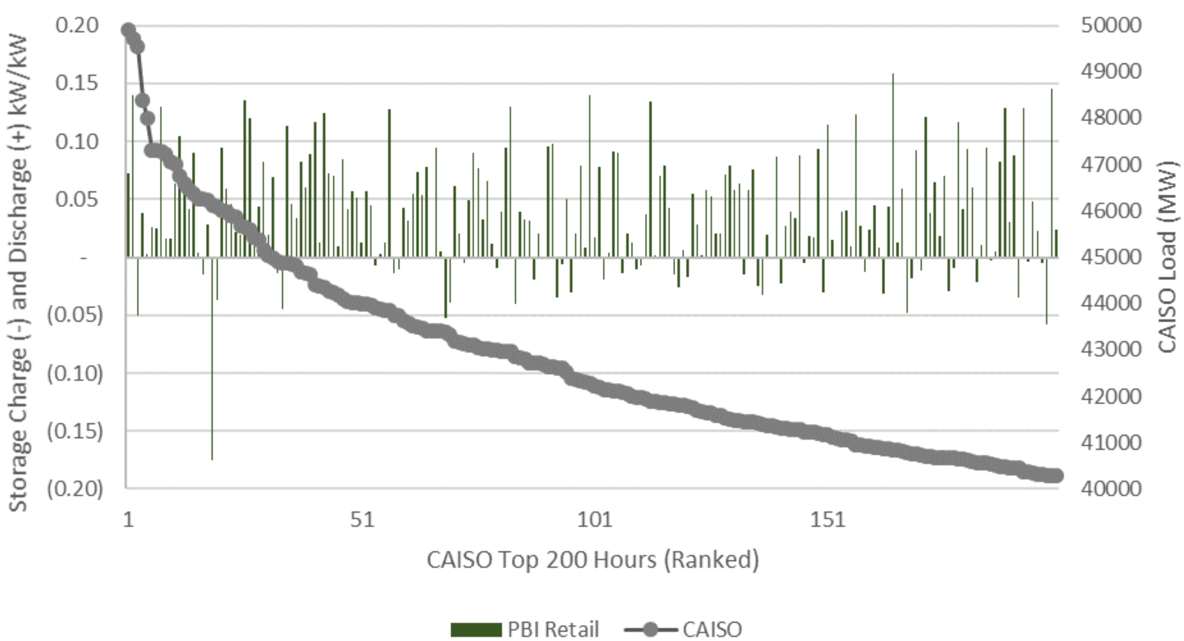


FIGURE C-5: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (PBI SCHOOL)

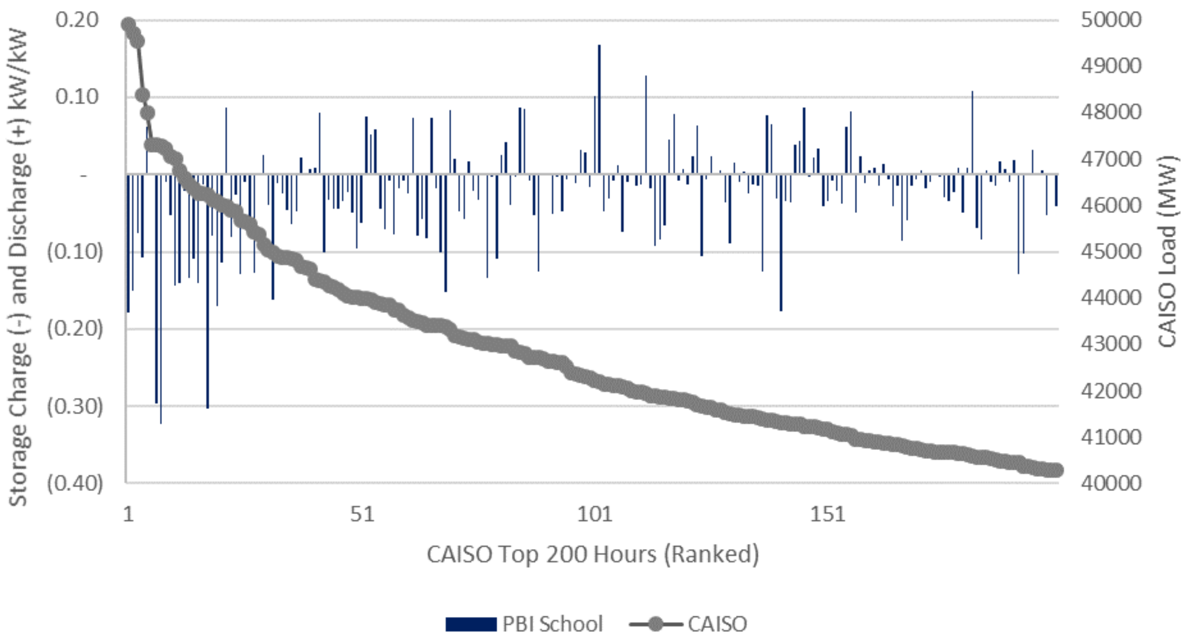


FIGURE C-6: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI INDUSTRIAL)

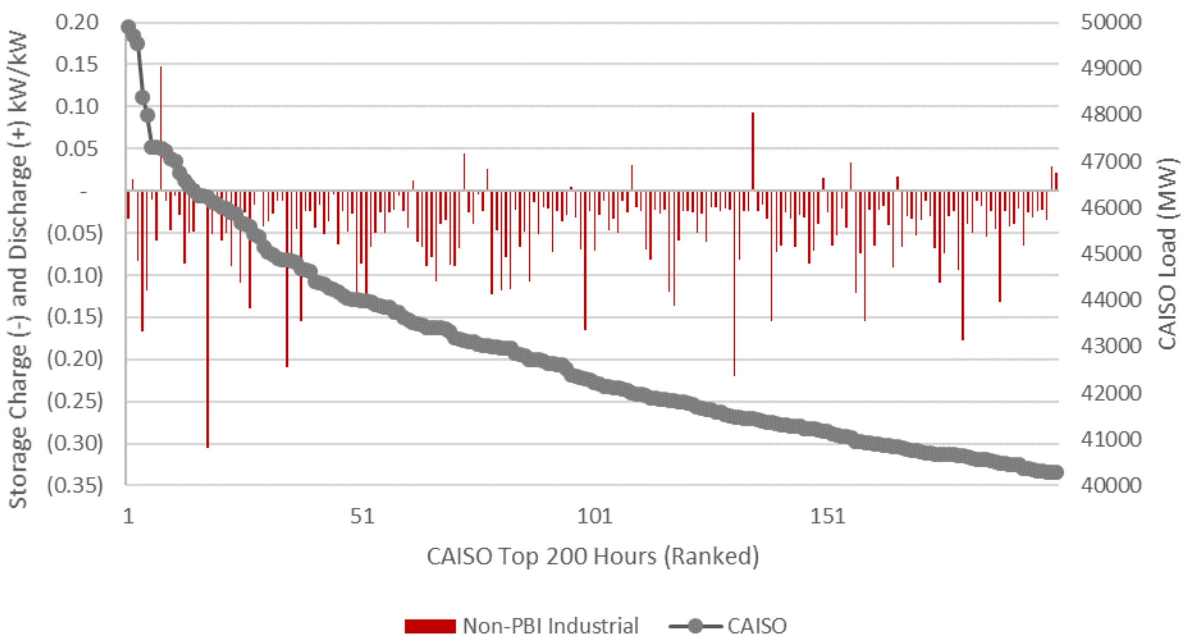


FIGURE C-7: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI OFFICE)

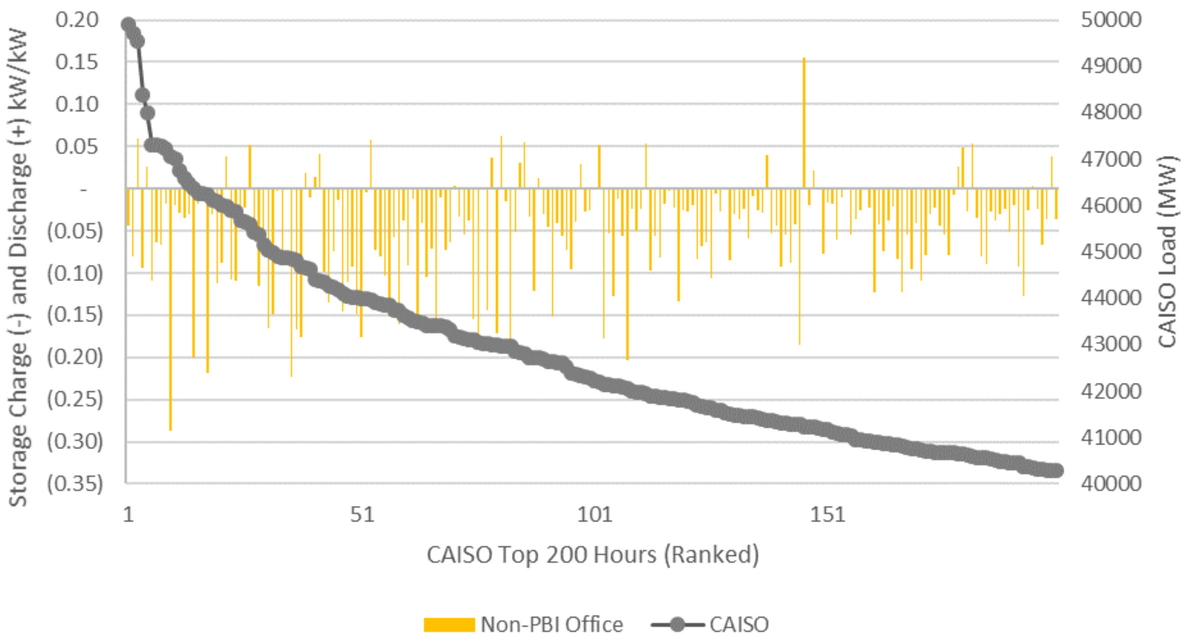


FIGURE C-8: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI OTHER)

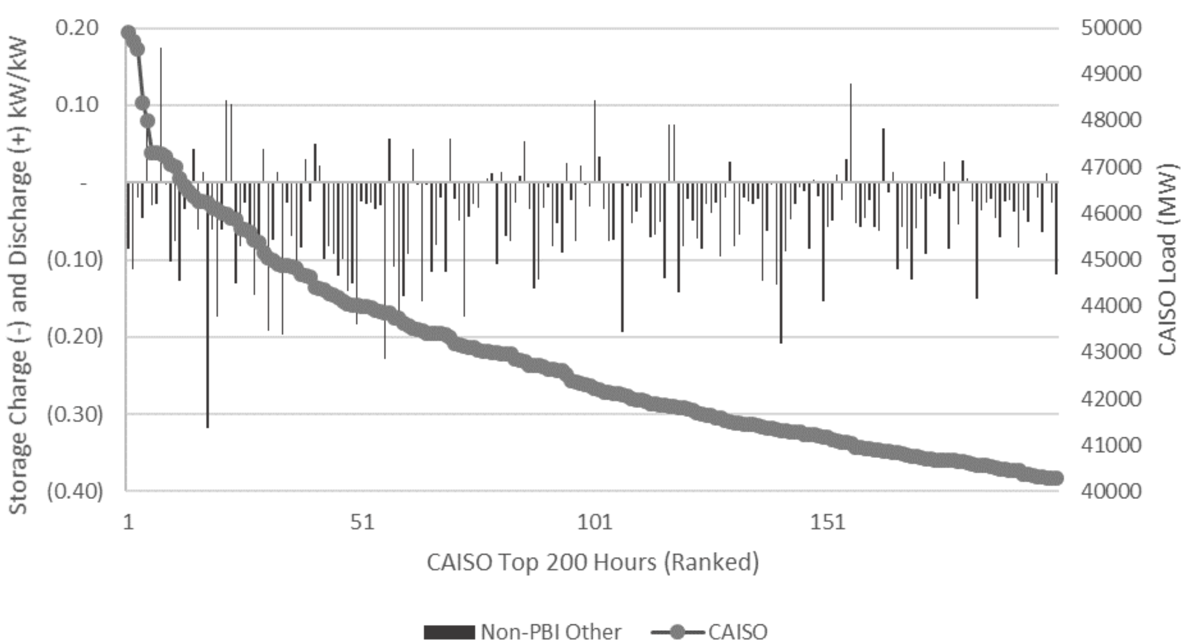


FIGURE C-9: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI RETAIL)

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

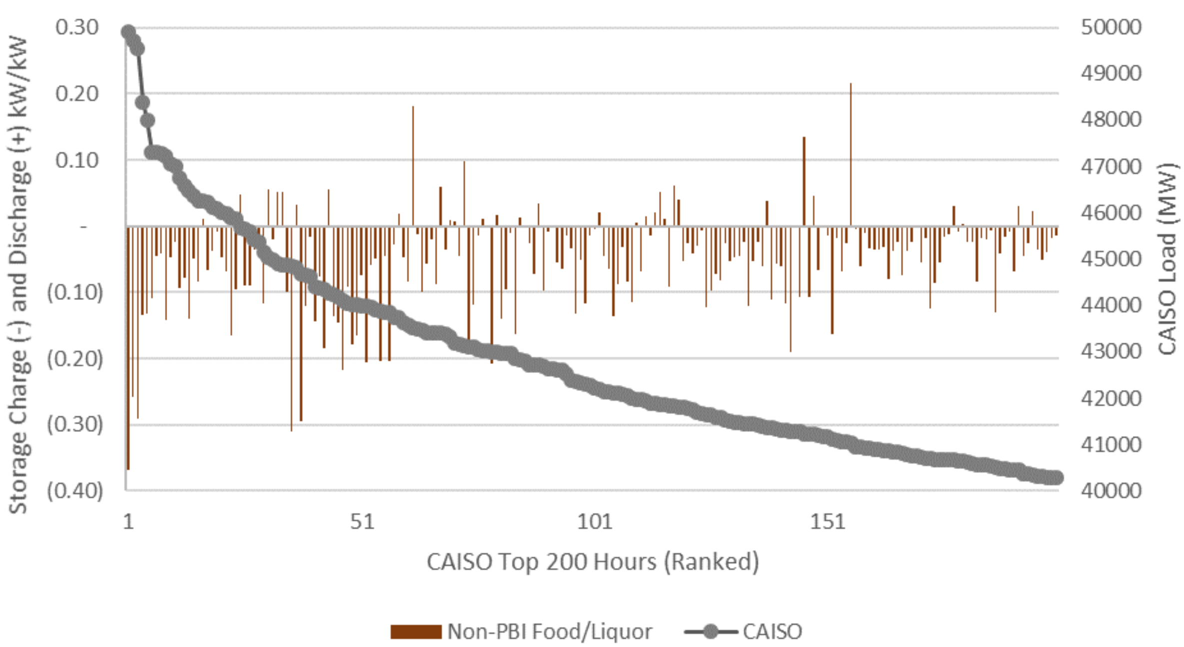


FIGURE C-11: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS (NON-PBI HOTEL)

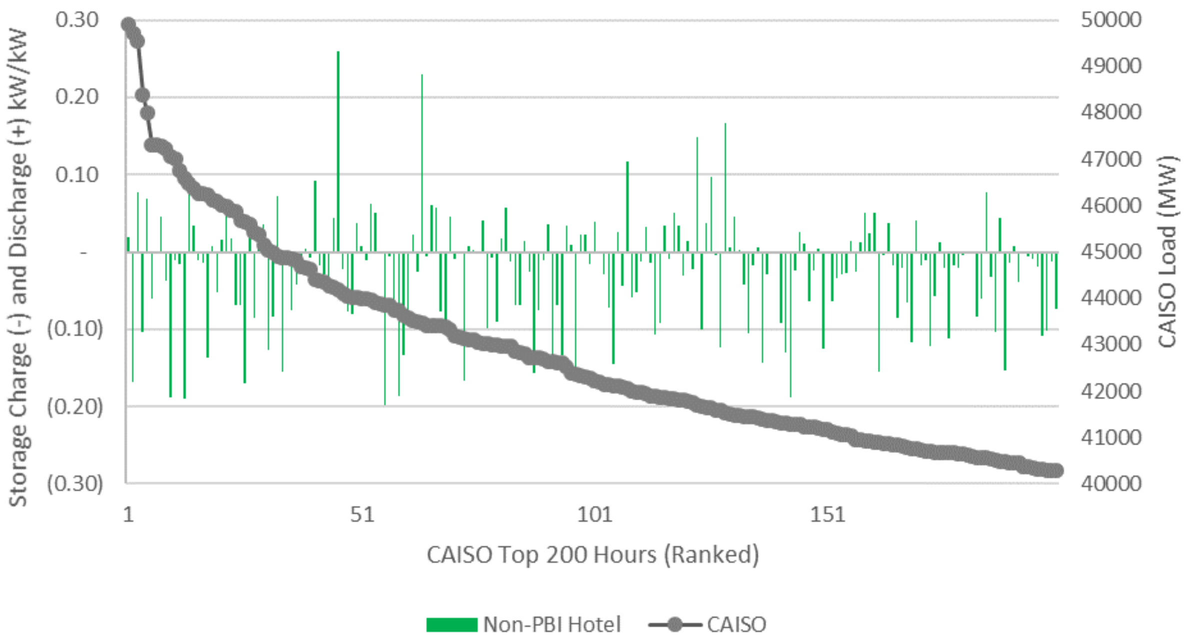


FIGURE C-12: AVERAGE HOURLY DISCHARGE/CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI INDUSTRIAL

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
0	0.019	0.015	0.010	0.022	0.025	0.028	0.025	0.037	0.036	0.034	0.041	0.042
1	0.017	0.014	0.010	0.022	0.024	0.028	0.024	0.034	0.032	0.032	0.038	0.038
2	0.016	0.014	0.010	0.021	0.026	0.028	0.026	0.037	0.038	0.039	0.041	0.040
3	0.015	0.014	0.010	0.022	0.023	0.026	0.025	0.039	0.036	0.037	0.049	0.054
4	0.016	0.014	0.011	0.010	0.006	0.006	0.009	0.012	0.013	0.011	0.043	0.052
5	0.020	0.017	0.010	0.010	0.007	0.006	0.010	0.011	0.012	0.010	0.017	0.017
6	0.020	0.016	0.012	0.013	0.009	0.011	0.013	0.013	0.019	0.015	0.019	0.018
7	0.024	0.018	0.019	0.017	0.011	0.012	0.014	0.015	0.015	0.011	0.019	0.023
8	0.026	0.026	0.031	0.034	0.023	0.022	0.024	0.024	0.025	0.021	0.019	0.015
9	0.050	0.051	0.036	0.033	0.029	0.027	0.029	0.025	0.023	0.023	0.037	0.029
10	0.045	0.048	0.033	0.024	0.027	0.027	0.030	0.027	0.023	0.025	0.036	0.029
11	0.039	0.044	0.038	0.030	0.064	0.071	0.054	0.069	0.058	0.059	0.036	0.031
12	0.037	0.042	0.042	0.031	0.066	0.074	0.055	0.072	0.067	0.060	0.041	0.036
13	0.037	0.045	0.045	0.032	0.071	0.066	0.060	0.073	0.067	0.058	0.040	0.037
14	0.038	0.045	0.043	0.033	0.102	0.106	0.113	0.115	0.111	0.076	0.038	0.038
15	0.043	0.043	0.042	0.039	0.108	0.134	0.127	0.139	0.130	0.079	0.037	0.041
16	0.047	0.047	0.073	0.083	0.132	0.151	0.142	0.171	0.148	0.095	0.046	0.034
17	0.091	0.078	0.137	0.141	0.079	0.048	0.057	0.060	0.057	0.093	0.074	0.052
18	0.148	0.133	0.197	0.198	0.117	0.085	0.093	0.085	0.103	0.129	0.114	0.090
19	0.220	0.205	0.225	0.213	0.150	0.109	0.126	0.110	0.117	0.140	0.148	0.118
20	0.217	0.215	0.137	0.105	0.074	0.064	0.077	0.069	0.072	0.068	0.128	0.110
21	0.117	0.111	0.068	0.051	0.054	0.060	0.060	0.079	0.064	0.054	0.070	0.050
22	0.033	0.031	0.038	0.065	0.061	0.067	0.065	0.078	0.065	0.070	0.064	0.054
23	0.073	0.061	0.025	0.024	0.030	0.033	0.030	0.041	0.038	0.037	0.075	0.074

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
0	-0.271	-0.262	-0.209	-0.213	-0.218	-0.231	-0.232	-0.249	-0.250	-0.200	-0.230	-0.192
1	-0.230	-0.223	-0.161	-0.163	-0.162	-0.179	-0.166	-0.183	-0.172	-0.128	-0.177	-0.166
2	-0.164	-0.157	-0.111	-0.117	-0.113	-0.122	-0.112	-0.119	-0.104	-0.093	-0.115	-0.122
3	-0.115	-0.109	-0.082	-0.084	-0.087	-0.082	-0.076	-0.089	-0.078	-0.077	-0.080	-0.082
4	-0.079	-0.080	-0.060	-0.059	-0.066	-0.059	-0.053	-0.061	-0.058	-0.058	-0.066	-0.070
5	-0.058	-0.060	-0.043	-0.038	-0.040	-0.036	-0.030	-0.029	-0.030	-0.032	-0.047	-0.049
6	-0.040	-0.039	-0.033	-0.035	-0.034	-0.029	-0.023	-0.022	-0.022	-0.021	-0.029	-0.031
7	-0.031	-0.030	-0.032	-0.025	-0.023	-0.021	-0.020	-0.016	-0.017	-0.017	-0.025	-0.024
8	-0.023	-0.026	-0.041	-0.030	-0.026	-0.021	-0.023	-0.027	-0.021	-0.019	-0.023	-0.023
9	-0.034	-0.040	-0.042	-0.027	-0.024	-0.020	-0.022	-0.032	-0.022	-0.020	-0.031	-0.031
10	-0.035	-0.037	-0.039	-0.032	-0.028	-0.026	-0.028	-0.036	-0.028	-0.022	-0.030	-0.029
11	-0.039	-0.033	-0.035	-0.020	-0.017	-0.014	-0.021	-0.023	-0.019	-0.017	-0.030	-0.034
12	-0.029	-0.030	-0.031	-0.019	-0.014	-0.017	-0.020	-0.021	-0.018	-0.016	-0.023	-0.028
13	-0.029	-0.025	-0.029	-0.018	-0.015	-0.014	-0.017	-0.021	-0.025	-0.020	-0.026	-0.025
14	-0.028	-0.026	-0.029	-0.016	-0.017	-0.014	-0.016	-0.021	-0.024	-0.018	-0.026	-0.023
15	-0.031	-0.023	-0.028	-0.016	-0.016	-0.012	-0.012	-0.017	-0.016	-0.014	-0.026	-0.022
16	-0.027	-0.025	-0.030	-0.015	-0.015	-0.011	-0.010	-0.014	-0.012	-0.016	-0.024	-0.025
17	-0.027	-0.024	-0.031	-0.020	-0.019	-0.021	-0.020	-0.027	-0.025	-0.025	-0.025	-0.022
18	-0.029	-0.025	-0.030	-0.018	-0.012	-0.014	-0.014	-0.017	-0.017	-0.020	-0.020	-0.023
19	-0.032	-0.030	-0.030	-0.020	-0.008	-0.012	-0.011	-0.015	-0.017	-0.017	-0.020	-0.021
20	-0.032	-0.031	-0.036	-0.034	-0.040	-0.032	-0.034	-0.032	-0.033	-0.045	-0.029	-0.019
21	-0.040	-0.037	-0.127	-0.203	-0.209	-0.182	-0.197	-0.203	-0.205	-0.242	-0.068	-0.038
22	-0.222	-0.207	-0.185	-0.174	-0.192	-0.195	-0.202	-0.234	-0.236	-0.207	-0.224	-0.170
23	-0.178	-0.162	-0.204	-0.239	-0.261	-0.262	-0.274	-0.295	-0.293	-0.259	-0.200	-0.145

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

Mean AES kWh/Rebated kW During Period

	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	0.001	0.005	0.006	0.014	0.016	0.011	0.030	0.044	0.039	0.100	0.062	0.069
1	0.011	0.015	0.008	0.003	0.003	0.005	0.028	0.038	0.035	0.088	0.065	0.073
2	0.000	0.004	0.003	0.006	0.004	0.005	0.029	0.040	0.036	0.089	0.059	0.067
3	0.001	0.004	0.002	0.011	0.006	0.004	0.028	0.037	0.037	0.095	0.058	0.066
4	0.002	0.004	0.004	0.008	0.008	0.008	0.032	0.019	0.026	0.046	0.056	0.070
5	0.003	0.004	0.009	0.012	0.019	0.023	0.047	0.025	0.029	0.056	0.027	0.026
6	0.005	0.008	0.011	0.027	0.026	0.027	0.044	0.021	0.023	0.046	0.022	0.024
7	0.008	0.020	0.020	0.036	0.037	0.023	0.031	0.021	0.031	0.046	0.017	0.035
8	0.029	0.028	0.040	0.070	0.066	0.044	0.045	0.036	0.062	0.075	0.029	0.040
9	0.076	0.069	0.067	0.077	0.064	0.045	0.050	0.044	0.057	0.067	0.043	0.064
10	0.058	0.068	0.091	0.068	0.071	0.051	0.060	0.070	0.063	0.065	0.051	0.069
11	0.059	0.070	0.102	0.073	0.076	0.054	0.086	0.104	0.107	0.094	0.067	0.080
12	0.071	0.084	0.116	0.089	0.072	0.049	0.093	0.112	0.117	0.099	0.088	0.079
13	0.070	0.087	0.124	0.107	0.071	0.050	0.074	0.088	0.094	0.071	0.097	0.086
14	0.071	0.087	0.127	0.111	0.086	0.073	0.083	0.095	0.102	0.081	0.081	0.079
15	0.069	0.094	0.119	0.110	0.084	0.064	0.075	0.084	0.098	0.089	0.082	0.071
16	0.079	0.095	0.091	0.081	0.050	0.095	0.071	0.071	0.093	0.101	0.079	0.060
17	0.044	0.071	0.068	0.061	0.045	0.079	0.045	0.049	0.070	0.099	0.075	0.064
18	0.047	0.052	0.068	0.097	0.055	0.029	0.044	0.044	0.063	0.092	0.051	0.058
19	0.054	0.057	0.061	0.076	0.056	0.037	0.061	0.055	0.091	0.111	0.038	0.051
20	0.064	0.073	0.038	0.030	0.064	0.048	0.055	0.047	0.070	0.075	0.032	0.053
21	0.026	0.029	0.022	0.014	0.105	0.062	0.049	0.068	0.091	0.149	0.035	0.032
22	0.004	0.009	0.015	0.020	0.036	0.024	0.053	0.063	0.060	0.124	0.082	0.093
23	0.025	0.026	0.005	0.001	0.002	0.001	0.027	0.036	0.034	0.082	0.066	0.075

Mean AES kWh/Rebated kW During Period

	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	-0.163	-0.187	-0.233	-0.233	-0.187	-0.151	-0.155	-0.174	-0.183	-0.237	-0.174	-0.187
1	-0.161	-0.181	-0.210	-0.166	-0.130	-0.109	-0.121	-0.147	-0.154	-0.214	-0.162	-0.175
2	-0.128	-0.144	-0.169	-0.107	-0.086	-0.063	-0.087	-0.113	-0.129	-0.180	-0.143	-0.143
3	-0.077	-0.093	-0.115	-0.075	-0.058	-0.039	-0.072	-0.093	-0.109	-0.150	-0.130	-0.141
4	-0.040	-0.053	-0.085	-0.046	-0.046	-0.036	-0.060	-0.074	-0.088	-0.102	-0.101	-0.144
5	-0.020	-0.030	-0.050	-0.022	-0.023	-0.023	-0.046	-0.044	-0.056	-0.061	-0.056	-0.084
6	-0.017	-0.025	-0.025	-0.021	-0.013	-0.013	-0.035	-0.018	-0.028	-0.053	-0.030	-0.047
7	-0.015	-0.019	-0.011	-0.011	-0.018	-0.009	-0.023	-0.012	-0.020	-0.036	-0.018	-0.030
8	-0.009	-0.012	-0.011	-0.009	-0.021	-0.008	-0.035	-0.024	-0.028	-0.053	-0.013	-0.019
9	-0.012	-0.018	-0.013	-0.011	-0.019	-0.007	-0.030	-0.022	-0.028	-0.051	-0.018	-0.027
10	-0.014	-0.019	-0.015	-0.013	-0.020	-0.010	-0.029	-0.019	-0.027	-0.045	-0.017	-0.029
11	-0.014	-0.022	-0.018	-0.011	-0.023	-0.018	-0.029	-0.020	-0.026	-0.042	-0.021	-0.028
12	-0.015	-0.022	-0.015	-0.010	-0.022	-0.014	-0.029	-0.020	-0.027	-0.036	-0.048	-0.031
13	-0.016	-0.026	-0.016	-0.014	-0.029	-0.013	-0.060	-0.064	-0.064	-0.075	-0.054	-0.032
14	-0.017	-0.027	-0.019	-0.015	-0.031	-0.014	-0.046	-0.050	-0.055	-0.064	-0.079	-0.034
15	-0.019	-0.025	-0.023	-0.022	-0.033	-0.016	-0.032	-0.031	-0.032	-0.042	-0.066	-0.035
16	-0.017	-0.024	-0.023	-0.017	-0.028	-0.020	-0.034	-0.024	-0.031	-0.042	-0.026	-0.031
17	-0.020	-0.018	-0.021	-0.018	-0.040	-0.028	-0.048	-0.039	-0.038	-0.059	-0.020	-0.028
18	-0.021	-0.018	-0.017	-0.017	-0.035	-0.084	-0.050	-0.029	-0.030	-0.056	-0.020	-0.028
19	-0.014	-0.019	-0.015	-0.025	-0.022	-0.066	-0.041	-0.028	-0.031	-0.052	-0.024	-0.032
20	-0.017	-0.039	-0.020	-0.024	-0.020	-0.022	-0.033	-0.033	-0.054	-0.064	-0.037	-0.032
21	-0.020	-0.036	-0.066	-0.154	-0.121	-0.107	-0.135	-0.145	-0.189	-0.208	-0.052	-0.097
22	-0.150	-0.153	-0.165	-0.234	-0.204	-0.155	-0.146	-0.205	-0.232	-0.255	-0.136	-0.179
23	-0.162	-0.177	-0.219	-0.264	-0.234	-0.170	-0.173	-0.205	-0.200	-0.273	-0.206	-0.184

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

Mean AES kWh/Rebated kW During Period

	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	0.000	0.001	0.006	0.011	0.022	0.012	0.011	0.047	0.066	0.068	0.066	0.052
1	0.003	0.010	0.004	0.000	0.013	0.001	0.000	0.032	0.048	0.049	0.072	0.065
2	0.000	0.000	0.000	0.000	0.008	0.000	0.000	0.031	0.046	0.049	0.060	0.053
3	0.000	0.000	0.000	0.000	0.008	0.000	0.000	0.031	0.047	0.048	0.057	0.051
4	0.000	0.000	0.001	0.000	0.008	0.001	0.001	0.001	0.002	0.002	0.050	0.051
5	0.000	0.001	0.001	0.003	0.009	0.002	0.003	0.005	0.003	0.004	0.003	0.002
6	0.004	0.001	0.002	0.002	0.010	0.002	0.001	0.001	0.003	0.004	0.004	0.001
7	0.007	0.003	0.003	0.005	0.009	0.004	0.004	0.002	0.005	0.002	0.003	0.002
8	0.008	0.008	0.010	0.018	0.020	0.013	0.014	0.007	0.011	0.012	0.003	0.002
9	0.013	0.016	0.022	0.026	0.030	0.020	0.026	0.014	0.018	0.026	0.006	0.006
10	0.016	0.027	0.029	0.030	0.037	0.032	0.037	0.026	0.031	0.039	0.011	0.012
11	0.018	0.028	0.030	0.025	0.031	0.037	0.043	0.031	0.029	0.034	0.016	0.015
12	0.013	0.027	0.020	0.014	0.017	0.032	0.027	0.025	0.022	0.023	0.014	0.015
13	0.011	0.012	0.013	0.010	0.017	0.028	0.025	0.028	0.018	0.016	0.010	0.010
14	0.014	0.005	0.009	0.007	0.039	0.035	0.031	0.034	0.015	0.028	0.011	0.007
15	0.010	0.006	0.007	0.006	0.040	0.036	0.032	0.036	0.045	0.027	0.011	0.006
16	0.018	0.010	0.014	0.024	0.048	0.045	0.038	0.038	0.053	0.031	0.013	0.025
17	0.076	0.051	0.056	0.060	0.033	0.039	0.025	0.021	0.028	0.031	0.063	0.039
18	0.143	0.086	0.094	0.084	0.042	0.050	0.047	0.039	0.063	0.045	0.074	0.056
19	0.194	0.121	0.105	0.070	0.042	0.044	0.051	0.041	0.070	0.051	0.075	0.062
20	0.191	0.108	0.075	0.038	0.031	0.026	0.030	0.024	0.045	0.034	0.041	0.060
21	0.089	0.066	0.028	0.006	0.019	0.003	0.000	0.044	0.076	0.081	0.033	0.026
22	0.004	0.003	0.004	0.007	0.019	0.004	0.001	0.045	0.071	0.075	0.085	0.071
23	0.021	0.008	0.005	0.001	0.012	0.001	0.000	0.040	0.058	0.052	0.075	0.068

Mean AES kWh/Rebated kW During Period

	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	-0.148	-0.108	-0.109	-0.054	-0.074	-0.072	-0.066	-0.109	-0.142	-0.141	-0.118	-0.121
1	-0.162	-0.108	-0.081	-0.036	-0.036	-0.044	-0.023	-0.078	-0.100	-0.107	-0.126	-0.127
2	-0.139	-0.066	-0.047	-0.030	-0.021	-0.024	-0.007	-0.054	-0.078	-0.081	-0.116	-0.117
3	-0.133	-0.054	-0.022	-0.026	-0.016	-0.010	-0.003	-0.043	-0.067	-0.067	-0.103	-0.099
4	-0.084	-0.028	-0.012	-0.019	-0.014	-0.007	-0.002	-0.014	-0.030	-0.032	-0.083	-0.087
5	-0.050	-0.017	-0.008	-0.015	-0.016	-0.010	-0.004	-0.005	-0.006	-0.006	-0.041	-0.053
6	-0.037	-0.011	-0.007	-0.017	-0.029	-0.016	-0.005	-0.009	-0.007	-0.011	-0.006	-0.011
7	-0.028	-0.007	-0.007	-0.013	-0.016	-0.025	-0.005	-0.007	-0.008	-0.009	-0.008	-0.009
8	-0.012	-0.006	-0.007	-0.013	-0.014	-0.021	-0.006	-0.008	-0.009	-0.009	-0.005	-0.007
9	-0.012	-0.007	-0.008	-0.010	-0.013	-0.011	-0.007	-0.009	-0.008	-0.010	-0.002	-0.007
10	-0.013	-0.006	-0.009	-0.012	-0.012	-0.009	-0.009	-0.009	-0.008	-0.009	-0.003	-0.007
11	-0.015	-0.007	-0.009	-0.015	-0.014	-0.010	-0.014	-0.013	-0.011	-0.011	-0.003	-0.007
12	-0.017	-0.010	-0.011	-0.013	-0.014	-0.016	-0.018	-0.015	-0.011	-0.015	-0.004	-0.009
13	-0.019	-0.017	-0.016	-0.015	-0.018	-0.028	-0.025	-0.018	-0.013	-0.020	-0.006	-0.012
14	-0.019	-0.022	-0.020	-0.020	-0.019	-0.017	-0.023	-0.017	-0.014	-0.025	-0.005	-0.017
15	-0.020	-0.022	-0.019	-0.021	-0.021	-0.014	-0.021	-0.018	-0.015	-0.028	-0.007	-0.017
16	-0.017	-0.014	-0.012	-0.013	-0.018	-0.012	-0.020	-0.017	-0.017	-0.027	-0.012	-0.011
17	-0.010	-0.005	-0.008	-0.013	-0.026	-0.018	-0.028	-0.029	-0.044	-0.022	-0.009	-0.012
18	-0.013	-0.007	-0.008	-0.015	-0.032	-0.025	-0.031	-0.028	-0.040	-0.023	-0.009	-0.014
19	-0.017	-0.009	-0.015	-0.025	-0.038	-0.022	-0.027	-0.022	-0.035	-0.025	-0.017	-0.012
20	-0.042	-0.036	-0.029	-0.040	-0.053	-0.030	-0.036	-0.027	-0.035	-0.029	-0.067	-0.010
21	-0.043	-0.046	-0.083	-0.095	-0.099	-0.087	-0.092	-0.111	-0.133	-0.126	-0.082	-0.040
22	-0.110	-0.118	-0.114	-0.085	-0.087	-0.082	-0.087	-0.105	-0.143	-0.123	-0.113	-0.099
23	-0.102	-0.100	-0.108	-0.067	-0.087	-0.077	-0.083	-0.112	-0.145	-0.142	-0.093	-0.095

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

Mean AES kWh/Rebated kW During Period

	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	0.028	0.015	0.000	0.023	0.027	0.029	0.023	0.076	0.089	0.098	0.102	0.100
1	0.027	0.015	0.000	0.026	0.026	0.029	0.022	0.075	0.089	0.098	0.100	0.100
2	0.027	0.014	0.000	0.023	0.026	0.029	0.022	0.078	0.096	0.107	0.105	0.100
3	0.028	0.015	0.000	0.023	0.027	0.029	0.022	0.079	0.099	0.109	0.119	0.106
4	0.027	0.015	0.000	0.002	0.002	0.002	0.002	0.007	0.012	0.015	0.105	0.107
5	0.027	0.015	0.001	0.002	0.002	0.003	0.001	0.003	0.008	0.010	0.018	0.010
6	0.046	0.018	0.004	0.010	0.009	0.005	0.004	0.005	0.009	0.010	0.009	0.006
7	0.036	0.016	0.025	0.031	0.011	0.005	0.007	0.015	0.020	0.019	0.013	0.006
8	0.044	0.035	0.056	0.054	0.003	0.004	0.004	0.012	0.020	0.021	0.024	0.010
9	0.073	0.065	0.063	0.043	0.012	0.014	0.005	0.010	0.016	0.019	0.023	0.009
10	0.074	0.063	0.067	0.045	0.021	0.023	0.013	0.014	0.011	0.024	0.029	0.008
11	0.081	0.062	0.061	0.044	0.032	0.020	0.017	0.027	0.031	0.028	0.034	0.013
12	0.067	0.056	0.052	0.042	0.034	0.026	0.022	0.033	0.032	0.029	0.036	0.016
13	0.058	0.042	0.042	0.039	0.032	0.028	0.031	0.037	0.031	0.040	0.047	0.022
14	0.053	0.036	0.032	0.032	0.066	0.063	0.058	0.067	0.071	0.057	0.049	0.021
15	0.046	0.032	0.036	0.033	0.079	0.077	0.067	0.089	0.094	0.078	0.048	0.027
16	0.046	0.033	0.042	0.048	0.079	0.079	0.078	0.096	0.107	0.091	0.032	0.027
17	0.090	0.064	0.093	0.079	0.049	0.029	0.031	0.039	0.047	0.075	0.036	0.032
18	0.117	0.102	0.180	0.106	0.067	0.049	0.049	0.061	0.059	0.080	0.047	0.054
19	0.190	0.170	0.187	0.106	0.089	0.068	0.085	0.080	0.049	0.059	0.074	0.091
20	0.233	0.209	0.150	0.105	0.108	0.102	0.095	0.104	0.086	0.061	0.076	0.097
21	0.177	0.159	0.060	0.121	0.155	0.149	0.168	0.205	0.202	0.187	0.052	0.043
22	0.028	0.017	0.013	0.115	0.151	0.151	0.174	0.218	0.195	0.195	0.134	0.120
23	0.066	0.039	0.005	0.026	0.027	0.029	0.023	0.078	0.091	0.100	0.132	0.141

Mean AES kWh/Rebated kW During Period

	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	-0.249	-0.195	-0.168	-0.174	-0.170	-0.187	-0.201	-0.270	-0.281	-0.254	-0.275	-0.253
1	-0.200	-0.168	-0.144	-0.158	-0.153	-0.164	-0.179	-0.239	-0.247	-0.220	-0.236	-0.217
2	-0.182	-0.158	-0.122	-0.133	-0.130	-0.137	-0.131	-0.185	-0.200	-0.201	-0.195	-0.176
3	-0.158	-0.139	-0.091	-0.089	-0.099	-0.098	-0.074	-0.129	-0.157	-0.179	-0.159	-0.146
4	-0.134	-0.112	-0.065	-0.067	-0.084	-0.071	-0.046	-0.093	-0.109	-0.130	-0.137	-0.132
5	-0.111	-0.086	-0.037	-0.035	-0.050	-0.027	-0.018	-0.018	-0.019	-0.029	-0.098	-0.100
6	-0.075	-0.062	-0.024	-0.029	-0.041	-0.025	-0.019	-0.016	-0.017	-0.028	-0.022	-0.018
7	-0.059	-0.046	-0.032	-0.025	-0.027	-0.021	-0.015	-0.016	-0.016	-0.026	-0.027	-0.019
8	-0.043	-0.039	-0.044	-0.034	-0.038	-0.029	-0.021	-0.022	-0.024	-0.036	-0.027	-0.017
9	-0.054	-0.048	-0.049	-0.039	-0.036	-0.025	-0.019	-0.019	-0.025	-0.035	-0.036	-0.023
10	-0.059	-0.045	-0.046	-0.042	-0.042	-0.026	-0.021	-0.024	-0.031	-0.033	-0.030	-0.024
11	-0.057	-0.046	-0.042	-0.041	-0.032	-0.025	-0.016	-0.018	-0.025	-0.025	-0.025	-0.018
12	-0.054	-0.043	-0.041	-0.041	-0.023	-0.022	-0.014	-0.017	-0.022	-0.022	-0.023	-0.018
13	-0.047	-0.037	-0.033	-0.037	-0.027	-0.018	-0.013	-0.024	-0.038	-0.036	-0.020	-0.016
14	-0.041	-0.036	-0.034	-0.033	-0.025	-0.021	-0.014	-0.029	-0.025	-0.030	-0.021	-0.014
15	-0.039	-0.036	-0.035	-0.033	-0.029	-0.021	-0.022	-0.026	-0.017	-0.020	-0.020	-0.013
16	-0.036	-0.037	-0.032	-0.038	-0.031	-0.021	-0.028	-0.030	-0.015	-0.024	-0.020	-0.015
17	-0.029	-0.033	-0.039	-0.041	-0.038	-0.029	-0.031	-0.034	-0.018	-0.018	-0.018	-0.013
18	-0.034	-0.032	-0.035	-0.037	-0.030	-0.029	-0.024	-0.019	-0.015	-0.015	-0.019	-0.014
19	-0.036	-0.035	-0.031	-0.028	-0.025	-0.023	-0.017	-0.021	-0.019	-0.016	-0.021	-0.014
20	-0.060	-0.034	-0.034	-0.033	-0.036	-0.034	-0.034	-0.040	-0.040	-0.044	-0.033	-0.015
21	-0.128	-0.082	-0.122	-0.132	-0.129	-0.124	-0.125	-0.185	-0.182	-0.196	-0.070	-0.042
22	-0.153	-0.109	-0.144	-0.117	-0.119	-0.113	-0.119	-0.202	-0.237	-0.222	-0.187	-0.187
23	-0.177	-0.133	-0.181	-0.219	-0.216	-0.228	-0.246	-0.327	-0.338	-0.302	-0.225	-0.198

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

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	0.001	0.002	0.007	0.011	0.012	0.011	0.023	0.051	0.060	0.044	0.037	0.042	0
1	0.010	0.011	0.005	0.001	0.000	0.000	0.017	0.048	0.058	0.039	0.040	0.045	1
2	0.000	0.001	0.001	0.001	0.001	0.000	0.017	0.047	0.058	0.039	0.037	0.041	2
3	0.000	0.001	0.001	0.001	0.000	0.000	0.017	0.047	0.058	0.039	0.037	0.042	3
4	0.000	0.001	0.002	0.001	0.002	0.001	0.021	0.039	0.043	0.025	0.036	0.042	4
5	0.001	0.001	0.004	0.005	0.010	0.004	0.026	0.052	0.045	0.026	0.025	0.028	5
6	0.006	0.006	0.015	0.008	0.012	0.004	0.023	0.050	0.044	0.030	0.029	0.033	6
7	0.029	0.024	0.019	0.012	0.014	0.007	0.020	0.052	0.046	0.030	0.038	0.047	7
8	0.048	0.031	0.022	0.018	0.027	0.013	0.021	0.061	0.053	0.035	0.031	0.045	8
9	0.042	0.023	0.027	0.029	0.040	0.021	0.025	0.073	0.059	0.047	0.033	0.037	9
10	0.041	0.027	0.039	0.038	0.064	0.035	0.040	0.098	0.068	0.066	0.040	0.043	10
11	0.043	0.029	0.049	0.042	0.064	0.040	0.038	0.095	0.062	0.082	0.045	0.050	11
12	0.034	0.028	0.056	0.049	0.068	0.044	0.041	0.104	0.062	0.096	0.046	0.052	12
13	0.030	0.029	0.050	0.040	0.051	0.038	0.044	0.091	0.054	0.085	0.046	0.054	13
14	0.029	0.029	0.032	0.025	0.024	0.023	0.038	0.063	0.045	0.054	0.043	0.048	14
15	0.027	0.028	0.024	0.019	0.010	0.012	0.036	0.047	0.043	0.031	0.034	0.038	15
16	0.032	0.032	0.043	0.054	0.009	0.010	0.029	0.045	0.046	0.034	0.039	0.079	16
17	0.089	0.086	0.052	0.039	0.008	0.001	0.018	0.041	0.039	0.036	0.091	0.082	17
18	0.074	0.082	0.062	0.051	0.013	0.004	0.021	0.045	0.041	0.035	0.074	0.068	18
19	0.069	0.078	0.049	0.033	0.021	0.012	0.029	0.052	0.047	0.037	0.064	0.065	19
20	0.045	0.059	0.025	0.013	0.012	0.009	0.022	0.043	0.043	0.029	0.033	0.064	20
21	0.031	0.027	0.011	0.004	0.004	0.008	0.020	0.052	0.059	0.040	0.030	0.037	21
22	0.008	0.008	0.009	0.006	0.002	0.002	0.018	0.053	0.057	0.039	0.039	0.044	22
23	0.018	0.014	0.005	0.001	0.000	0.000	0.018	0.051	0.055	0.038	0.042	0.049	23

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
0	-0.095	-0.086	-0.071	-0.054	-0.037	-0.028	-0.037	-0.077	-0.085	-0.063	-0.073	-0.090
1	-0.091	-0.084	-0.053	-0.039	-0.021	-0.015	-0.032	-0.073	-0.079	-0.055	-0.069	-0.079
2	-0.059	-0.062	-0.039	-0.030	-0.010	-0.011	-0.029	-0.059	-0.070	-0.049	-0.063	-0.073
3	-0.045	-0.048	-0.026	-0.023	-0.007	-0.005	-0.025	-0.057	-0.068	-0.048	-0.051	-0.060
4	-0.031	-0.033	-0.018	-0.015	-0.004	-0.003	-0.021	-0.047	-0.054	-0.035	-0.046	-0.054
5	-0.018	-0.021	-0.011	-0.008	-0.003	-0.004	-0.020	-0.042	-0.048	-0.028	-0.035	-0.047
6	-0.010	-0.012	-0.007	-0.007	-0.003	-0.008	-0.026	-0.042	-0.048	-0.028	-0.028	-0.037
7	-0.008	-0.008	-0.013	-0.010	-0.010	-0.010	-0.031	-0.042	-0.045	-0.029	-0.031	-0.040
8	-0.015	-0.015	-0.015	-0.008	-0.010	-0.006	-0.030	-0.047	-0.047	-0.033	-0.037	-0.052
9	-0.025	-0.020	-0.010	-0.006	-0.006	-0.003	-0.021	-0.041	-0.047	-0.035	-0.042	-0.063
10	-0.032	-0.016	-0.008	-0.006	-0.005	-0.002	-0.018	-0.036	-0.043	-0.033	-0.039	-0.060
11	-0.028	-0.014	-0.009	-0.007	-0.004	-0.004	-0.018	-0.034	-0.048	-0.030	-0.033	-0.052
12	-0.024	-0.010	-0.007	-0.005	-0.003	-0.004	-0.017	-0.032	-0.044	-0.028	-0.030	-0.041
13	-0.017	-0.010	-0.008	-0.008	-0.007	-0.008	-0.017	-0.040	-0.046	-0.032	-0.028	-0.035
14	-0.013	-0.011	-0.019	-0.021	-0.024	-0.017	-0.022	-0.057	-0.056	-0.051	-0.031	-0.036
15	-0.023	-0.019	-0.044	-0.045	-0.053	-0.030	-0.024	-0.103	-0.074	-0.094	-0.038	-0.044
16	-0.037	-0.037	-0.028	-0.010	-0.055	-0.032	-0.032	-0.118	-0.068	-0.098	-0.044	-0.038
17	-0.008	-0.006	-0.014	-0.015	-0.061	-0.037	-0.054	-0.141	-0.065	-0.085	-0.029	-0.036
18	-0.013	-0.006	-0.007	-0.010	-0.040	-0.028	-0.048	-0.104	-0.056	-0.061	-0.030	-0.043
19	-0.008	-0.006	-0.039	-0.063	-0.030	-0.020	-0.038	-0.078	-0.050	-0.053	-0.041	-0.045
20	-0.047	-0.064	-0.061	-0.052	-0.028	-0.018	-0.036	-0.068	-0.049	-0.051	-0.111	-0.044
21	-0.052	-0.062	-0.072	-0.059	-0.043	-0.016	-0.034	-0.075	-0.067	-0.070	-0.081	-0.102
22	-0.096	-0.086	-0.066	-0.041	-0.037	-0.021	-0.035	-0.091	-0.084	-0.066	-0.084	-0.108
23	-0.063	-0.054	-0.070	-0.053	-0.037	-0.022	-0.037	-0.087	-0.086	-0.066	-0.073	-0.091

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

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	0.061	0.055	0.014	0.029	0.033	0.036	0.039	0.040	0.007	0.005	0.015	0.021	0
1	0.050	0.043	0.017	0.033	0.039	0.047	0.032	0.034	0.006	0.001	0.001	0.003	1
2	0.024	0.029	0.005	0.030	0.034	0.041	0.033	0.037	0.007	0.001	0.000	0.002	2
3	0.026	0.029	0.003	0.028	0.033	0.035	0.033	0.040	0.008	0.002	0.004	0.005	3
4	0.024	0.030	0.008	0.016	0.019	0.013	0.013	0.016	0.015	0.015	0.009	0.014	4
5	0.029	0.042	0.025	0.028	0.039	0.028	0.027	0.025	0.022	0.039	0.041	0.017	5
6	0.049	0.052	0.037	0.031	0.050	0.046	0.035	0.031	0.027	0.033	0.053	0.032	6
7	0.074	0.059	0.076	0.060	0.058	0.051	0.038	0.044	0.024	0.037	0.051	0.028	7
8	0.073	0.085	0.091	0.062	0.066	0.061	0.034	0.051	0.025	0.041	0.048	0.031	8
9	0.076	0.096	0.108	0.071	0.069	0.059	0.044	0.057	0.038	0.059	0.054	0.029	9
10	0.077	0.092	0.109	0.062	0.080	0.077	0.057	0.061	0.040	0.053	0.065	0.032	10
11	0.053	0.076	0.105	0.067	0.085	0.080	0.058	0.070	0.049	0.057	0.044	0.023	11
12	0.062	0.087	0.090	0.070	0.074	0.061	0.045	0.049	0.038	0.049	0.045	0.023	12
13	0.055	0.078	0.090	0.061	0.057	0.056	0.033	0.039	0.036	0.036	0.037	0.019	13
14	0.047	0.073	0.082	0.042	0.027	0.032	0.017	0.036	0.023	0.020	0.024	0.017	14
15	0.034	0.071	0.077	0.041	0.025	0.023	0.013	0.021	0.015	0.013	0.014	0.013	15
16	0.034	0.066	0.105	0.094	0.026	0.026	0.020	0.020	0.016	0.010	0.018	0.030	16
17	0.059	0.120	0.107	0.070	0.032	0.029	0.018	0.015	0.006	0.022	0.060	0.017	17
18	0.068	0.091	0.088	0.049	0.029	0.017	0.014	0.017	0.004	0.017	0.057	0.026	18
19	0.075	0.085	0.040	0.006	0.008	0.007	0.005	0.007	0.001	0.012	0.043	0.027	19
20	0.039	0.041	0.009	0.003	0.004	0.005	0.009	0.007	0.003	0.012	0.020	0.017	20
21	0.044	0.040	0.009	0.029	0.034	0.038	0.036	0.036	0.005	0.006	0.011	0.013	21
22	0.028	0.031	0.005	0.028	0.033	0.037	0.034	0.036	0.006	0.007	0.004	0.005	22
23	0.029	0.029	0.015	0.038	0.039	0.041	0.049	0.041	0.010	0.017	0.016	0.009	23

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
0	-0.070	-0.073	-0.042	-0.061	-0.067	-0.073	-0.082	-0.074	-0.032	-0.038	-0.052	-0.041
1	-0.098	-0.097	-0.033	-0.053	-0.062	-0.065	-0.066	-0.066	-0.029	-0.024	-0.030	-0.030
2	-0.069	-0.078	-0.027	-0.053	-0.061	-0.069	-0.065	-0.064	-0.030	-0.023	-0.025	-0.019
3	-0.053	-0.066	-0.026	-0.053	-0.062	-0.076	-0.064	-0.066	-0.030	-0.023	-0.025	-0.020
4	-0.056	-0.066	-0.030	-0.044	-0.047	-0.051	-0.046	-0.053	-0.030	-0.029	-0.029	-0.025
5	-0.054	-0.071	-0.039	-0.039	-0.051	-0.044	-0.042	-0.048	-0.042	-0.038	-0.034	-0.032
6	-0.062	-0.078	-0.050	-0.046	-0.058	-0.046	-0.048	-0.049	-0.041	-0.056	-0.053	-0.042
7	-0.079	-0.083	-0.085	-0.072	-0.081	-0.066	-0.057	-0.051	-0.041	-0.050	-0.067	-0.056
8	-0.080	-0.086	-0.116	-0.099	-0.092	-0.083	-0.070	-0.063	-0.047	-0.085	-0.068	-0.046
9	-0.091	-0.123	-0.124	-0.083	-0.089	-0.086	-0.061	-0.078	-0.049	-0.062	-0.098	-0.053
10	-0.104	-0.129	-0.138	-0.101	-0.098	-0.096	-0.073	-0.091	-0.063	-0.082	-0.085	-0.052
11	-0.119	-0.132	-0.141	-0.092	-0.094	-0.103	-0.078	-0.083	-0.063	-0.088	-0.106	-0.062
12	-0.097	-0.120	-0.150	-0.100	-0.106	-0.109	-0.084	-0.100	-0.071	-0.090	-0.087	-0.046
13	-0.103	-0.121	-0.123	-0.097	-0.108	-0.101	-0.073	-0.090	-0.072	-0.087	-0.088	-0.045
14	-0.101	-0.115	-0.126	-0.085	-0.105	-0.100	-0.079	-0.084	-0.063	-0.075	-0.077	-0.035
15	-0.106	-0.117	-0.118	-0.083	-0.078	-0.066	-0.055	-0.060	-0.050	-0.047	-0.058	-0.038
16	-0.083	-0.112	-0.119	-0.081	-0.059	-0.054	-0.045	-0.050	-0.035	-0.040	-0.042	-0.047
17	-0.082	-0.113	-0.127	-0.092	-0.059	-0.059	-0.044	-0.061	-0.046	-0.037	-0.048	-0.049
18	-0.085	-0.126	-0.144	-0.102	-0.065	-0.058	-0.049	-0.044	-0.032	-0.049	-0.060	-0.038
19	-0.106	-0.141	-0.168	-0.132	-0.065	-0.058	-0.037	-0.043	-0.028	-0.041	-0.096	-0.056
20	-0.131	-0.161	-0.082	-0.029	-0.038	-0.030	-0.031	-0.029	-0.021	-0.037	-0.112	-0.048
21	-0.075	-0.074	-0.037	-0.057	-0.064	-0.066	-0.066	-0.062	-0.028	-0.034	-0.044	-0.041
22	-0.077	-0.080	-0.030	-0.054	-0.064	-0.066	-0.067	-0.064	-0.028	-0.026	-0.033	-0.029
23	-0.062	-0.068	-0.031	-0.058	-0.063	-0.066	-0.069	-0.067	-0.032	-0.038	-0.034	-0.024

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

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	0.006	0.003	0.004	0.005	0.006	0.017	0.017	0.011	0.016	0.013	0.003	0.001	0
1	0.018	0.017	0.006	0.001	0.001	0.001	0.001	0.002	0.001	0.001	0.012	0.016	1
2	0.003	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.001	2
3	0.004	0.001	0.001	0.001	0.003	0.001	0.001	0.001	0.000	0.001	0.000	0.001	3
4	0.005	0.001	0.001	0.002	0.001	0.003	0.002	0.001	0.001	0.002	0.000	0.002	4
5	0.008	0.004	0.006	0.008	0.004	0.008	0.006	0.003	0.004	0.010	0.004	0.004	5
6	0.032	0.018	0.023	0.011	0.014	0.023	0.017	0.009	0.011	0.014	0.008	0.019	6
7	0.062	0.019	0.012	0.004	0.009	0.017	0.011	0.006	0.008	0.005	0.008	0.015	7
8	0.026	0.009	0.008	0.010	0.020	0.031	0.024	0.017	0.016	0.010	0.006	0.007	8
9	0.037	0.015	0.009	0.015	0.030	0.045	0.040	0.035	0.025	0.020	0.008	0.017	9
10	0.035	0.020	0.018	0.023	0.032	0.057	0.052	0.054	0.029	0.034	0.011	0.014	10
11	0.032	0.019	0.025	0.023	0.028	0.046	0.028	0.040	0.023	0.024	0.018	0.020	11
12	0.026	0.018	0.026	0.031	0.030	0.047	0.036	0.042	0.027	0.036	0.014	0.017	12
13	0.026	0.018	0.027	0.035	0.035	0.049	0.038	0.052	0.028	0.043	0.022	0.026	13
14	0.029	0.017	0.028	0.036	0.036	0.055	0.042	0.047	0.036	0.045	0.023	0.025	14
15	0.019	0.015	0.028	0.029	0.028	0.040	0.034	0.040	0.026	0.032	0.016	0.023	15
16	0.015	0.008	0.017	0.041	0.019	0.036	0.027	0.022	0.023	0.027	0.013	0.021	16
17	0.049	0.026	0.014	0.017	0.012	0.012	0.010	0.014	0.017	0.023	0.021	0.013	17
18	0.025	0.017	0.011	0.010	0.007	0.011	0.012	0.009	0.010	0.010	0.009	0.006	18
19	0.010	0.005	0.007	0.008	0.005	0.008	0.011	0.010	0.008	0.006	0.001	0.003	19
20	0.011	0.009	0.004	0.004	0.002	0.006	0.006	0.006	0.005	0.005	0.001	0.003	20
21	0.008	0.001	0.004	0.007	0.001	0.005	0.006	0.008	0.004	0.005	0.001	0.005	21
22	0.010	0.002	0.002	0.005	0.001	0.003	0.003	0.004	0.002	0.003	0.001	0.002	22
23	0.006	0.002	0.003	0.002	0.002	0.005	0.003	0.002	0.001	0.000	0.000	0.001	23

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
0	-0.036	-0.027	-0.028	-0.033	-0.033	-0.042	-0.041	-0.033	-0.041	-0.037	-0.025	-0.022
1	-0.046	-0.041	-0.032	-0.027	-0.024	-0.030	-0.028	-0.028	-0.027	-0.026	-0.035	-0.033
2	-0.032	-0.028	-0.025	-0.025	-0.023	-0.028	-0.024	-0.025	-0.025	-0.022	-0.024	-0.021
3	-0.028	-0.024	-0.023	-0.024	-0.024	-0.025	-0.024	-0.025	-0.023	-0.022	-0.022	-0.018
4	-0.026	-0.028	-0.022	-0.024	-0.026	-0.026	-0.025	-0.024	-0.023	-0.022	-0.022	-0.018
5	-0.027	-0.025	-0.024	-0.027	-0.024	-0.028	-0.026	-0.025	-0.025	-0.024	-0.022	-0.019
6	-0.028	-0.029	-0.029	-0.032	-0.027	-0.039	-0.035	-0.028	-0.029	-0.036	-0.025	-0.021
7	-0.039	-0.034	-0.027	-0.026	-0.024	-0.029	-0.028	-0.023	-0.022	-0.025	-0.027	-0.028
8	-0.052	-0.030	-0.032	-0.030	-0.030	-0.038	-0.040	-0.034	-0.037	-0.032	-0.023	-0.024
9	-0.060	-0.034	-0.032	-0.031	-0.031	-0.044	-0.041	-0.045	-0.041	-0.033	-0.030	-0.028
10	-0.062	-0.035	-0.032	-0.034	-0.035	-0.051	-0.050	-0.041	-0.038	-0.036	-0.030	-0.033
11	-0.059	-0.040	-0.034	-0.037	-0.049	-0.069	-0.068	-0.056	-0.040	-0.046	-0.033	-0.034
12	-0.061	-0.038	-0.035	-0.037	-0.045	-0.051	-0.054	-0.049	-0.042	-0.039	-0.038	-0.038
13	-0.058	-0.040	-0.039	-0.039	-0.047	-0.062	-0.053	-0.056	-0.041	-0.041	-0.039	-0.033
14	-0.049	-0.039	-0.038	-0.051	-0.050	-0.071	-0.062	-0.074	-0.047	-0.053	-0.040	-0.036
15	-0.057	-0.044	-0.051	-0.057	-0.058	-0.094	-0.074	-0.077	-0.059	-0.071	-0.045	-0.047
16	-0.062	-0.052	-0.070	-0.064	-0.077	-0.083	-0.070	-0.085	-0.060	-0.077	-0.040	-0.045
17	-0.042	-0.042	-0.057	-0.068	-0.062	-0.084	-0.069	-0.064	-0.061	-0.055	-0.038	-0.044
18	-0.045	-0.044	-0.048	-0.064	-0.056	-0.080	-0.059	-0.071	-0.063	-0.062	-0.035	-0.042
19	-0.072	-0.046	-0.052	-0.059	-0.041	-0.055	-0.050	-0.055	-0.055	-0.052	-0.039	-0.040
20	-0.068	-0.048	-0.037	-0.033	-0.026	-0.031	-0.036	-0.031	-0.031	-0.029	-0.032	-0.031
21	-0.038	-0.031	-0.031	-0.035	-0.031	-0.039	-0.039	-0.033	-0.033	-0.034	-0.024	-0.022
22	-0.043	-0.030	-0.027	-0.033	-0.030	-0.043	-0.029	-0.029	-0.032	-0.027	-0.026	-0.026
23	-0.034	-0.028	-0.025	-0.033	-0.027	-0.029	-0.025	-0.029	-0.029	-0.029	-0.023	-0.026

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

	Mean AES kWh/Rebated kW During Period											
	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	0.002	0.025	0.041	0.042	0.046	0.045	0.031	0.046	0.036	0.007	0.000
1	0.035	0.032	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.035	0.039
2	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000
3	0.000	0.001	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.001	0.001	0.000
4	0.002	0.001	0.001	0.000	0.000	0.001	0.000	0.001	0.002	0.004	0.003	0.009
5	0.008	0.001	0.005	0.010	0.003	0.001	0.002	0.004	0.004	0.008	0.005	0.006
6	0.027	0.011	0.013	0.013	0.013	0.008	0.006	0.007	0.003	0.005	0.008	0.010
7	0.018	0.015	0.013	0.016	0.014	0.013	0.017	0.015	0.016	0.008	0.011	0.014
8	0.026	0.014	0.017	0.034	0.026	0.024	0.026	0.025	0.020	0.015	0.021	0.012
9	0.049	0.028	0.026	0.032	0.028	0.032	0.038	0.035	0.029	0.027	0.026	0.016
10	0.048	0.025	0.035	0.029	0.044	0.044	0.047	0.051	0.033	0.045	0.033	0.022
11	0.039	0.030	0.037	0.036	0.054	0.061	0.055	0.071	0.047	0.049	0.045	0.024
12	0.039	0.029	0.037	0.034	0.051	0.055	0.058	0.077	0.042	0.050	0.040	0.029
13	0.034	0.022	0.037	0.032	0.049	0.052	0.062	0.070	0.045	0.059	0.046	0.033
14	0.047	0.024	0.033	0.027	0.044	0.058	0.049	0.051	0.034	0.043	0.044	0.038
15	0.019	0.020	0.040	0.037	0.039	0.056	0.055	0.048	0.035	0.039	0.034	0.033
16	0.026	0.030	0.041	0.057	0.039	0.057	0.057	0.061	0.027	0.030	0.039	0.047
17	0.055	0.048	0.053	0.035	0.044	0.031	0.025	0.027	0.019	0.027	0.068	0.037
18	0.045	0.034	0.038	0.032	0.028	0.020	0.014	0.024	0.026	0.016	0.050	0.028
19	0.023	0.017	0.015	0.022	0.014	0.019	0.008	0.013	0.009	0.008	0.035	0.024
20	0.012	0.007	0.002	0.009	0.009	0.006	0.003	0.006	0.002	0.004	0.008	0.023
21	0.008	0.007	0.001	0.007	0.005	0.002	0.002	0.001	0.001	0.001	0.004	0.007
22	0.004	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.003
23	0.001	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.001	0.001	0.001	0.000

	Mean AES kWh/Rebated kW During Period											
	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	-0.020	-0.048	-0.063	-0.060	-0.058	-0.058	-0.048	-0.063	-0.053	-0.025	-0.023
1	-0.056	-0.055	-0.042	-0.028	-0.029	-0.027	-0.030	-0.026	-0.030	-0.023	-0.051	-0.054
2	-0.028	-0.027	-0.022	-0.020	-0.021	-0.018	-0.021	-0.019	-0.019	-0.017	-0.027	-0.024
3	-0.020	-0.020	-0.019	-0.020	-0.021	-0.019	-0.021	-0.020	-0.020	-0.017	-0.020	-0.016
4	-0.019	-0.019	-0.020	-0.021	-0.022	-0.019	-0.021	-0.021	-0.023	-0.018	-0.022	-0.017
5	-0.020	-0.019	-0.021	-0.026	-0.026	-0.020	-0.022	-0.022	-0.025	-0.020	-0.024	-0.022
6	-0.027	-0.025	-0.023	-0.029	-0.028	-0.020	-0.022	-0.022	-0.022	-0.023	-0.029	-0.027
7	-0.040	-0.026	-0.022	-0.028	-0.027	-0.023	-0.024	-0.024	-0.028	-0.022	-0.027	-0.026
8	-0.034	-0.022	-0.034	-0.049	-0.042	-0.034	-0.046	-0.045	-0.043	-0.031	-0.028	-0.028
9	-0.058	-0.035	-0.044	-0.055	-0.047	-0.038	-0.045	-0.054	-0.041	-0.036	-0.054	-0.044
10	-0.059	-0.044	-0.048	-0.062	-0.053	-0.040	-0.051	-0.056	-0.055	-0.043	-0.047	-0.044
11	-0.070	-0.046	-0.058	-0.055	-0.067	-0.049	-0.060	-0.059	-0.058	-0.049	-0.053	-0.045
12	-0.084	-0.052	-0.051	-0.052	-0.055	-0.056	-0.063	-0.068	-0.060	-0.044	-0.060	-0.043
13	-0.068	-0.051	-0.049	-0.053	-0.057	-0.055	-0.064	-0.081	-0.059	-0.046	-0.060	-0.052
14	-0.074	-0.050	-0.056	-0.055	-0.070	-0.072	-0.073	-0.095	-0.067	-0.067	-0.064	-0.055
15	-0.073	-0.055	-0.061	-0.050	-0.064	-0.082	-0.078	-0.086	-0.066	-0.070	-0.071	-0.058
16	-0.058	-0.048	-0.054	-0.051	-0.065	-0.082	-0.092	-0.076	-0.060	-0.082	-0.073	-0.050
17	-0.052	-0.043	-0.046	-0.070	-0.086	-0.114	-0.104	-0.104	-0.055	-0.084	-0.059	-0.043
18	-0.052	-0.051	-0.056	-0.049	-0.084	-0.087	-0.074	-0.073	-0.053	-0.060	-0.057	-0.039
19	-0.076	-0.044	-0.079	-0.057	-0.065	-0.068	-0.049	-0.061	-0.052	-0.045	-0.061	-0.030
20	-0.067	-0.067	-0.057	-0.038	-0.041	-0.036	-0.025	-0.032	-0.029	-0.022	-0.106	-0.027
21	-0.036	-0.028	-0.037	-0.058	-0.051	-0.041	-0.033	-0.030	-0.027	-0.033	-0.051	-0.052
22	-0.028	-0.030	-0.029	-0.037	-0.042	-0.040	-0.032	-0.022	-0.021	-0.032	-0.036	-0.054
23	-0.021	-0.024	-0.023	-0.024	-0.024	-0.026	-0.032	-0.022	-0.020	-0.027	-0.023	-0.033

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

	Mean AES kWh/Rebated kW During Period											
	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	0.004	0.015	0.019	0.019	0.020	0.022	0.012	0.018	0.011	0.004	0.001
1	0.022	0.022	0.009	0.000	0.000	0.001	0.001	0.000	0.000	0.003	0.017	0.017
2	0.000	0.002	0.001	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.000	0.001
3	0.001	0.000	0.000	0.001	0.001	0.002	0.000	0.000	0.000	0.000	0.002	0.001
4	0.001	0.001	0.002	0.003	0.001	0.002	0.002	0.003	0.002	0.003	0.003	0.001
5	0.004	0.005	0.006	0.005	0.002	0.004	0.002	0.006	0.002	0.017	0.006	0.003
6	0.016	0.019	0.006	0.004	0.002	0.005	0.003	0.004	0.001	0.003	0.005	0.004
7	0.007	0.011	0.007	0.005	0.006	0.015	0.013	0.012	0.007	0.014	0.002	0.003
8	0.015	0.021	0.009	0.010	0.014	0.018	0.019	0.014	0.006	0.013	0.010	0.004
9	0.021	0.015	0.018	0.015	0.024	0.028	0.024	0.019	0.013	0.015	0.010	0.007
10	0.021	0.026	0.028	0.020	0.043	0.040	0.038	0.044	0.021	0.023	0.013	0.009
11	0.030	0.025	0.030	0.031	0.052	0.049	0.040	0.049	0.020	0.037	0.022	0.012
12	0.041	0.033	0.047	0.034	0.062	0.057	0.039	0.054	0.024	0.049	0.028	0.017
13	0.043	0.040	0.053	0.038	0.058	0.058	0.039	0.055	0.022	0.043	0.034	0.030
14	0.042	0.033	0.043	0.033	0.053	0.051	0.035	0.046	0.018	0.043	0.026	0.027
15	0.038	0.037	0.042	0.037	0.057	0.044	0.028	0.038	0.019	0.030	0.030	0.025
16	0.033	0.037	0.056	0.068	0.046	0.050	0.024	0.033	0.021	0.021	0.019	0.037
17	0.053	0.063	0.056	0.041	0.026	0.029	0.012	0.017	0.016	0.029	0.063	0.037
18	0.050	0.059	0.067	0.067	0.030	0.020	0.007	0.026	0.019	0.021	0.038	0.018
19	0.026	0.031	0.029	0.032	0.039	0.044	0.043	0.029	0.011	0.016	0.020	0.010
20	0.012	0.013	0.013	0.010	0.008	0.013	0.016	0.007	0.002	0.010	0.008	0.007
21	0.005	0.006	0.008	0.011	0.005	0.008	0.009	0.006	0.006	0.005	0.004	0.002
22	0.004	0.005	0.007	0.006	0.003	0.004	0.002	0.004	0.002	0.003	0.006	0.003
23	0.004	0.004	0.002	0.004	0.003	0.004	0.005	0.003	0.002	0.002	0.001	0.003

	Mean AES kWh/Rebated kW During Period											
	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	-0.038	-0.043	-0.052	-0.056	-0.048	-0.047	-0.035	-0.045	-0.033	-0.024	-0.020
1	-0.047	-0.055	-0.044	-0.033	-0.035	-0.033	-0.030	-0.028	-0.030	-0.023	-0.039	-0.034
2	-0.031	-0.041	-0.033	-0.026	-0.026	-0.026	-0.024	-0.026	-0.024	-0.021	-0.025	-0.021
3	-0.025	-0.031	-0.028	-0.027	-0.026	-0.025	-0.023	-0.025	-0.024	-0.020	-0.023	-0.016
4	-0.024	-0.027	-0.026	-0.028	-0.027	-0.025	-0.023	-0.025	-0.024	-0.021	-0.023	-0.015
5	-0.024	-0.025	-0.025	-0.031	-0.028	-0.026	-0.024	-0.032	-0.026	-0.030	-0.026	-0.014
6	-0.028	-0.035	-0.027	-0.031	-0.028	-0.027	-0.027	-0.027	-0.024	-0.034	-0.029	-0.018
7	-0.032	-0.032	-0.029	-0.024	-0.025	-0.029	-0.030	-0.030	-0.025	-0.033	-0.024	-0.016
8	-0.026	-0.032	-0.029	-0.028	-0.027	-0.034	-0.028	-0.032	-0.027	-0.032	-0.026	-0.016
9	-0.035	-0.042	-0.029	-0.030	-0.037	-0.035	-0.036	-0.031	-0.025	-0.035	-0.028	-0.019
10	-0.031	-0.035	-0.036	-0.032	-0.040	-0.039	-0.038	-0.034	-0.025	-0.032	-0.027	-0.020
11	-0.037	-0.037	-0.038	-0.038	-0.048	-0.044	-0.047	-0.043	-0.035	-0.040	-0.033	-0.021
12	-0.046	-0.041	-0.045	-0.046	-0.057	-0.054	-0.053	-0.054	-0.032	-0.047	-0.047	-0.025
13	-0.048	-0.044	-0.050	-0.043	-0.071	-0.065	-0.059	-0.065	-0.036	-0.057	-0.052	-0.037
14	-0.052	-0.048	-0.054	-0.050	-0.067	-0.065	-0.057	-0.082	-0.037	-0.058	-0.052	-0.046
15	-0.051	-0.048	-0.057	-0.045	-0.064	-0.069	-0.056	-0.067	-0.042	-0.057	-0.048	-0.043
16	-0.052	-0.049	-0.056	-0.054	-0.081	-0.072	-0.046	-0.072	-0.047	-0.063	-0.047	-0.046
17	-0.044	-0.042	-0.067	-0.075	-0.085	-0.092	-0.061	-0.077	-0.056	-0.056	-0.038	-0.044
18	-0.050	-0.044	-0.070	-0.070	-0.065	-0.062	-0.035	-0.053	-0.034	-0.044	-0.049	-0.043
19	-0.059	-0.055	-0.083	-0.072	-0.050	-0.048	-0.027	-0.036	-0.025	-0.038	-0.050	-0.035
20	-0.078	-0.071	-0.082	-0.079	-0.076	-0.056	-0.030	-0.031	-0.026	-0.030	-0.058	-0.029
21	-0.091	-0.088	-0.071	-0.055	-0.059	-0.068	-0.064	-0.060	-0.038	-0.047	-0.050	-0.044
22	-0.051	-0.044	-0.034	-0.040	-0.040	-0.040	-0.044	-0.030	-0.033	-0.026	-0.034	-0.022
23	-0.035	-0.037	-0.033	-0.038	-0.036	-0.029	-0.027	-0.026	-0.028	-0.022	-0.022	-0.020

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

	Mean AES kWh/Rebated kW During Period											
	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	0.019	0.020	0.004	0.024	0.031	0.033	0.031	0.034	0.011	0.005	0.008	0.011
1	0.014	0.019	0.003	0.023	0.029	0.029	0.026	0.025	0.009	0.006	0.006	0.008
2	0.012	0.018	0.002	0.021	0.024	0.025	0.023	0.027	0.007	0.003	0.004	0.007
3	0.011	0.018	0.004	0.022	0.029	0.029	0.025	0.022	0.007	0.002	0.003	0.006
4	0.011	0.019	0.005	0.004	0.004	0.003	0.001	0.007	0.004	0.005	0.006	0.009
5	0.016	0.025	0.014	0.006	0.005	0.005	0.001	0.012	0.009	0.011	0.009	0.015
6	0.024	0.032	0.020	0.011	0.012	0.009	0.006	0.026	0.017	0.015	0.016	0.024
7	0.025	0.034	0.027	0.014	0.016	0.015	0.014	0.020	0.019	0.013	0.017	0.025
8	0.014	0.032	0.040	0.023	0.024	0.030	0.037	0.039	0.033	0.028	0.016	0.022
9	0.019	0.047	0.045	0.029	0.025	0.032	0.041	0.046	0.034	0.033	0.023	0.033
10	0.021	0.044	0.049	0.027	0.028	0.043	0.043	0.053	0.040	0.036	0.029	0.027
11	0.018	0.044	0.046	0.024	0.036	0.046	0.047	0.052	0.037	0.034	0.025	0.027
12	0.013	0.039	0.047	0.025	0.030	0.048	0.046	0.051	0.042	0.038	0.024	0.021
13	0.013	0.043	0.053	0.028	0.032	0.058	0.056	0.061	0.045	0.046	0.022	0.022
14	0.014	0.043	0.055	0.038	0.040	0.073	0.066	0.072	0.048	0.052	0.024	0.023
15	0.016	0.045	0.063	0.046	0.046	0.079	0.077	0.072	0.047	0.056	0.024	0.025
16	0.016	0.047	0.068	0.054	0.050	0.102	0.108	0.066	0.042	0.050	0.028	0.031
17	0.037	0.059	0.060	0.042	0.039	0.056	0.052	0.045	0.028	0.046	0.051	0.046
18	0.046	0.074	0.082	0.051	0.022	0.032	0.033	0.032	0.024	0.044	0.053	0.054
19	0.042	0.075	0.061	0.047	0.027	0.029	0.026	0.032	0.022	0.034	0.051	0.050
20	0.033	0.055	0.028	0.021	0.013	0.016	0.012	0.018	0.011	0.016	0.041	0.046
21	0.019	0.027	0.020	0.039	0.039	0.042	0.038	0.044	0.016	0.016	0.022	0.024
22	0.017	0.030	0.011	0.031	0.032	0.035	0.032	0.040	0.012	0.010	0.019	0.021
23	0.012	0.022	0.008	0.029	0.033	0.037	0.034	0.041	0.014	0.008	0.011	0.012

	Mean AES kWh/Rebated kW During Period											
	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	-0.039	-0.057	-0.041	-0.057	-0.061	-0.062	-0.056	-0.057	-0.040	-0.036	-0.041	-0.038
1	-0.038	-0.051	-0.031	-0.051	-0.053	-0.056	-0.055	-0.058	-0.034	-0.030	-0.036	-0.031
2	-0.032	-0.048	-0.026	-0.048	-0.055	-0.056	-0.051	-0.045	-0.031	-0.025	-0.031	-0.024
3	-0.033	-0.043	-0.022	-0.044	-0.048	-0.050	-0.047	-0.046	-0.026	-0.022	-0.026	-0.022
4	-0.029	-0.040	-0.022	-0.035	-0.045	-0.043	-0.040	-0.038	-0.024	-0.022	-0.024	-0.019
5	-0.030	-0.041	-0.022	-0.022	-0.026	-0.022	-0.019	-0.024	-0.023	-0.023	-0.023	-0.021
6	-0.034	-0.041	-0.028	-0.024	-0.030	-0.024	-0.023	-0.031	-0.025	-0.031	-0.029	-0.029
7	-0.042	-0.047	-0.043	-0.023	-0.019	-0.016	-0.019	-0.023	-0.019	-0.021	-0.033	-0.040
8	-0.032	-0.043	-0.057	-0.038	-0.035	-0.032	-0.037	-0.048	-0.037	-0.039	-0.027	-0.033
9	-0.042	-0.067	-0.071	-0.042	-0.041	-0.039	-0.050	-0.062	-0.045	-0.046	-0.040	-0.054
10	-0.043	-0.084	-0.070	-0.046	-0.044	-0.049	-0.058	-0.068	-0.056	-0.051	-0.045	-0.058
11	-0.042	-0.079	-0.070	-0.046	-0.042	-0.058	-0.061	-0.073	-0.054	-0.055	-0.046	-0.057
12	-0.043	-0.066	-0.070	-0.043	-0.041	-0.055	-0.057	-0.069	-0.050	-0.053	-0.045	-0.049
13	-0.035	-0.066	-0.070	-0.046	-0.043	-0.053	-0.057	-0.067	-0.054	-0.054	-0.046	-0.042
14	-0.033	-0.063	-0.075	-0.047	-0.042	-0.058	-0.061	-0.066	-0.057	-0.060	-0.045	-0.039
15	-0.031	-0.068	-0.076	-0.056	-0.046	-0.065	-0.068	-0.071	-0.062	-0.063	-0.047	-0.044
16	-0.035	-0.072	-0.083	-0.062	-0.046	-0.075	-0.074	-0.079	-0.073	-0.072	-0.047	-0.050
17	-0.033	-0.071	-0.091	-0.070	-0.059	-0.113	-0.116	-0.100	-0.083	-0.074	-0.045	-0.051
18	-0.042	-0.075	-0.086	-0.062	-0.061	-0.104	-0.110	-0.098	-0.067	-0.059	-0.050	-0.055
19	-0.040	-0.072	-0.060	-0.052	-0.050	-0.089	-0.094	-0.086	-0.053	-0.053	-0.050	-0.056
20	-0.044	-0.059	-0.040	-0.031	-0.037	-0.057	-0.056	-0.051	-0.035	-0.040	-0.052	-0.057
21	-0.034	-0.043	-0.051	-0.075	-0.093	-0.118	-0.100	-0.102	-0.057	-0.065	-0.042	-0.042
22	-0.053	-0.070	-0.060	-0.076	-0.093	-0.105	-0.079	-0.083	-0.047	-0.060	-0.064	-0.063
23	-0.047	-0.066	-0.047	-0.069	-0.070	-0.073	-0.060	-0.071	-0.036	-0.045	-0.057	-0.055

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

Mean AES kWh/Rebated kW During Period

	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	0.009	0.004	0.008	0.011	0.010	0.011	0.011	0.008	0.011	0.009	0.004	0.000
1	0.016	0.012	0.002	0.000	0.009	0.001	0.001	0.000	0.000	0.002	0.008	0.009
2	0.003	0.002	0.001	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
3	0.001	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
4	0.002	0.000	0.001	0.006	0.003	0.003	0.002	0.001	0.000	0.001	0.001	0.000
5	0.015	0.007	0.012	0.021	0.015	0.021	0.004	0.003	0.002	0.004	0.003	0.003
6	0.022	0.017	0.021	0.022	0.021	0.027	0.012	0.008	0.005	0.003	0.004	0.006
7	0.022	0.022	0.020	0.021	0.024	0.032	0.019	0.011	0.011	0.006	0.008	0.006
8	0.022	0.023	0.027	0.036	0.032	0.048	0.029	0.016	0.019	0.011	0.011	0.008
9	0.037	0.035	0.031	0.035	0.036	0.067	0.050	0.025	0.019	0.015	0.014	0.012
10	0.047	0.050	0.039	0.046	0.063	0.119	0.097	0.069	0.038	0.044	0.018	0.013
11	0.064	0.049	0.063	0.071	0.070	0.093	0.069	0.052	0.033	0.046	0.036	0.020
12	0.064	0.066	0.069	0.082	0.083	0.108	0.088	0.053	0.027	0.057	0.050	0.031
13	0.077	0.078	0.072	0.079	0.072	0.085	0.064	0.039	0.023	0.058	0.051	0.032
14	0.049	0.052	0.059	0.048	0.041	0.053	0.038	0.019	0.013	0.041	0.038	0.038
15	0.040	0.036	0.046	0.034	0.035	0.044	0.020	0.018	0.008	0.036	0.028	0.024
16	0.045	0.033	0.053	0.052	0.021	0.034	0.024	0.014	0.010	0.028	0.028	0.034
17	0.067	0.072	0.055	0.034	0.014	0.065	0.034	0.026	0.012	0.020	0.044	0.024
18	0.044	0.043	0.031	0.029	0.012	0.043	0.030	0.027	0.006	0.009	0.017	0.013
19	0.033	0.033	0.014	0.006	0.003	0.015	0.008	0.006	0.001	0.001	0.008	0.007
20	0.017	0.010	0.006	0.004	0.002	0.006	0.002	0.001	0.000	0.001	0.001	0.003
21	0.005	0.003	0.002	0.000	0.001	0.003	0.000	0.000	0.000	0.000	0.001	0.001
22	0.002	0.000	0.001	0.000	0.000	0.001	0.000	0.001	0.000	0.000	0.001	0.000
23	0.004	0.002	0.001	0.001	0.001	0.002	0.000	0.000	0.000	0.001	0.000	0.000

Mean AES kWh/Rebated kW During Period

	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	-0.026	-0.021	-0.026	-0.031	-0.030	-0.033	-0.031	-0.027	-0.030	-0.027	-0.020	-0.015
1	-0.035	-0.031	-0.023	-0.023	-0.033	-0.026	-0.025	-0.022	-0.022	-0.023	-0.027	-0.024
2	-0.029	-0.025	-0.020	-0.019	-0.022	-0.022	-0.021	-0.021	-0.019	-0.018	-0.023	-0.018
3	-0.020	-0.019	-0.019	-0.018	-0.019	-0.023	-0.021	-0.021	-0.019	-0.017	-0.020	-0.015
4	-0.022	-0.020	-0.019	-0.021	-0.020	-0.024	-0.021	-0.020	-0.019	-0.017	-0.019	-0.013
5	-0.023	-0.022	-0.021	-0.024	-0.022	-0.022	-0.021	-0.020	-0.019	-0.016	-0.019	-0.015
6	-0.032	-0.029	-0.031	-0.033	-0.028	-0.031	-0.027	-0.023	-0.020	-0.018	-0.017	-0.016
7	-0.031	-0.029	-0.033	-0.044	-0.042	-0.048	-0.028	-0.022	-0.021	-0.018	-0.018	-0.017
8	-0.040	-0.035	-0.040	-0.042	-0.038	-0.040	-0.034	-0.020	-0.024	-0.019	-0.024	-0.019
9	-0.039	-0.038	-0.042	-0.047	-0.048	-0.054	-0.040	-0.026	-0.025	-0.023	-0.025	-0.020
10	-0.050	-0.050	-0.045	-0.054	-0.051	-0.068	-0.051	-0.030	-0.027	-0.028	-0.028	-0.025
11	-0.063	-0.059	-0.051	-0.052	-0.053	-0.095	-0.083	-0.050	-0.036	-0.041	-0.031	-0.026
12	-0.067	-0.061	-0.061	-0.069	-0.062	-0.080	-0.066	-0.039	-0.041	-0.046	-0.038	-0.032
13	-0.070	-0.067	-0.071	-0.101	-0.094	-0.120	-0.096	-0.067	-0.046	-0.056	-0.046	-0.035
14	-0.087	-0.082	-0.082	-0.089	-0.101	-0.118	-0.080	-0.069	-0.047	-0.067	-0.063	-0.041
15	-0.090	-0.068	-0.081	-0.091	-0.092	-0.124	-0.088	-0.067	-0.051	-0.072	-0.066	-0.053
16	-0.081	-0.075	-0.085	-0.075	-0.085	-0.107	-0.068	-0.063	-0.045	-0.071	-0.053	-0.055
17	-0.084	-0.072	-0.083	-0.079	-0.066	-0.090	-0.060	-0.043	-0.034	-0.072	-0.052	-0.051
18	-0.094	-0.090	-0.082	-0.064	-0.040	-0.083	-0.056	-0.032	-0.029	-0.053	-0.069	-0.050
19	-0.071	-0.077	-0.078	-0.067	-0.038	-0.095	-0.057	-0.048	-0.024	-0.039	-0.049	-0.034
20	-0.057	-0.085	-0.044	-0.031	-0.023	-0.061	-0.041	-0.041	-0.015	-0.019	-0.041	-0.024
21	-0.043	-0.033	-0.033	-0.023	-0.017	-0.046	-0.041	-0.028	-0.018	-0.015	-0.017	-0.017
22	-0.037	-0.031	-0.028	-0.018	-0.021	-0.028	-0.022	-0.018	-0.017	-0.016	-0.018	-0.014
23	-0.025	-0.024	-0.022	-0.019	-0.021	-0.022	-0.019	-0.018	-0.018	-0.018	-0.020	-0.014