2016 SGIP ADVANCED ENERGY STORAGE IMPACT EVALUATION

Submitted to:
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SGIP Working Group

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2016 SGIP Energy Storage Evaluation Report Foreword

This evaluation of the impact of Self-Generation Incentive Program (SGIP) energy storage systems in 2016 contains several notable findings. On average, SGIP systems are helping to reduce load during system peak hours, and reduce customer demand overall. Customer bills are likely lowered by the performance of SGIP systems. Overall, SGIP systems are estimated to have provided benefits to Pacific Gas and Electric (PG&E) and Southern California Edison (SCE), and their ratepayers, in the form of avoided costs in 2016.

While the evaluation's findings indicate that SGIP is generally helping to reduce system peak demand, customer peak demand and customer bills, a key goal of the SGIP program is to reduce greenhouse gas (GHG) emissions, which is not currently being met. The evaluators believe that this is principally due to rate designs that are misaligned with peak marginal GHG hours, which prevent customers from receiving signals that would lead to GHG reductions. The evaluation also reveals other system performance issues that require attention. These include data availability for residential and certain small non-residential systems, low efficiency and increased system peak demand arising from smaller systems, and renewable integration for all systems.

To meet these goals improvements should be considered to ensure that SGIP systems reduce GHG emissions, effectively integrate intermittent renewable resources, provide reliable data, and meet minimum efficiency requirements.

Steps are now underway to address the GHG emissions issues including a focus on rate design, but these will take time to be fully implemented for all utilities. For example, Commission Decision (D.) 17-08-030[1] made substantial changes to San Diego Gas & Electric's rate design by moving to a 4-9PM peak period and adopting a new super off-peak period during springtime months to encourage load consumption at times when renewable oversupply conditions occur on the grid. This should encourage energy storage charging and discharging patterns that better align with GHG reductions and renewable integration objectives. PG&E and SCE have pending rate cases before the Commission where similar proposals are under consideration. While rate design updates address some issues identified in the 2016 evaluation, Staff believes there are additional opportunities to better align system performance with SGIP goals.

Energy Division proposes to address the results of the 2016 Evaluation Report at a public workshop on November 17th, 2017 at the CPUC's headquarters in San Francisco. All interested parties are welcome to attend and discuss solutions to the problems identified by the evaluation. After the workshop, Energy Division expects to draft a Staff Proposal that contains recommended changes to SGIP for the CPUC's consideration.

[1] Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M194/K599/194599448.PDF

Energy Division preliminarily proposes the following possible solutions for consideration by parties ahead of the November 17th workshop. Parties are welcome to use these ideas as a starting point for their own proposals, or prepare other proposals for discussion at the workshop. Energy Division's preliminary proposals are to:

- Extend SGIP's Performance Based Incentive requirements to all energy storage systems over 10kW in size to ensure that performance data is provided for these systems
- Ensure that all SGIP projects going forward meet efficiency requirements by either
    - establishing a penalty process, or
    - withholding a portion of the incentive payments, for those developers that fail to meet efficiency requirements
- Require complete and accurate data from residential and small non-residential projects, subject to penalties for those developers that fail to provide sufficiently reliable data
- To the extent updated rate designs do not address the problem, modify the operating requirements of SGIP systems such that a certain number of cycles are required to charge during periods of low marginal GHG emissions and discharge during periods of high marginal GHG emissions

Please contact Energy Division's SGIP analyst – Patrick Doherty – if you wish to participate in the workshop. He can be reached at PD1@cpuc.ca.gov or (415) 703-5032.

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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.

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:

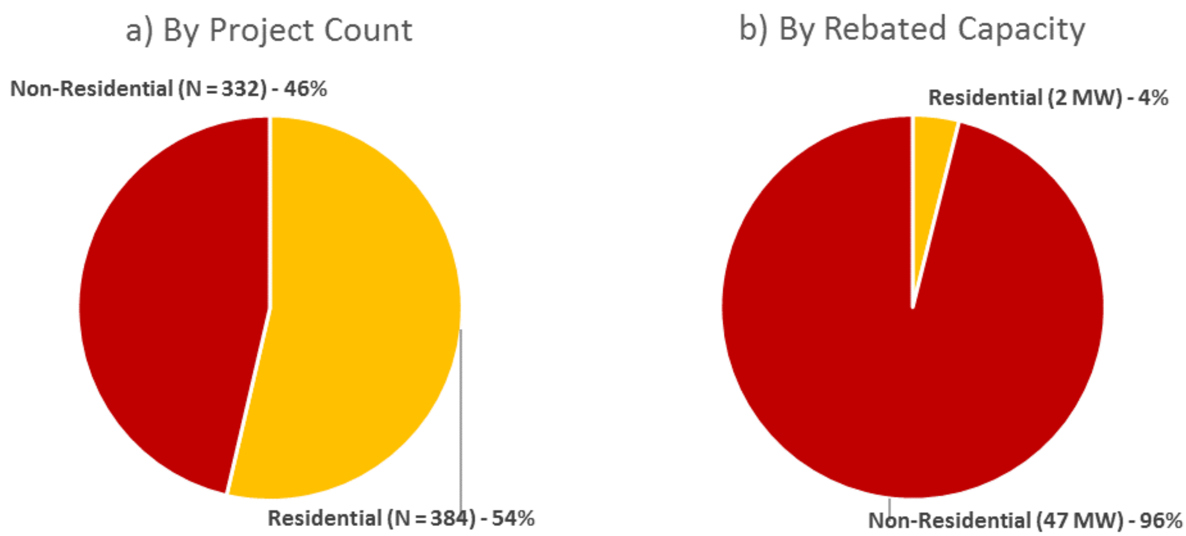
- Net greenhouse gas (GHG) emissions of AES systems as a class (i.e., all SGIP energy storage projects combined), and net GHG emissions differentiated between residential and non-residential systems, and between systems paired with renewable generation and non-paired systems.
- Timing and duration of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

This SGIP storage impact evaluation report is prepared in response to the CPUC's M&E Plan for calendar year 2016.

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, 2016. The population consists of 716 behind-the-meter (BTM) battery storage projects installed across the residential and non-residential sectors representing almost 49 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



While the number of projects installed across the sectors is almost equal, most of the SGIP storage rebated capacity (96%) is installed at non-residential customer sites. Non-residential projects are almost always larger and therefore have a significant contribution to total program impacts.

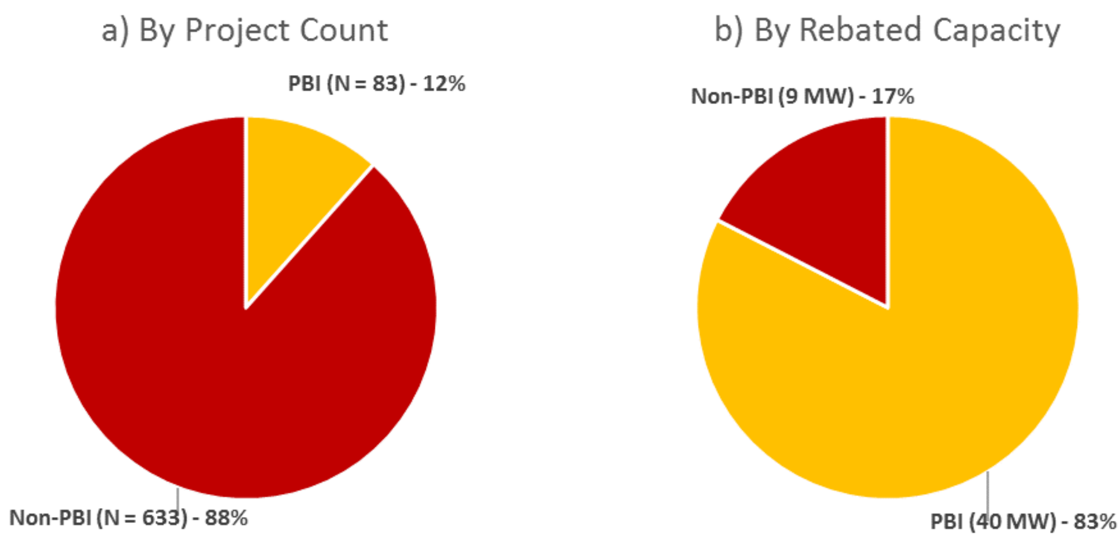
Projects are further split into two categories: 1) Performance Based Incentive (PBI)[2] projects and 2) non-PBI projects. PBI projects are those with a rebated capacity equal to or greater than 30 kW that applied to the SGIP on or after PY 2011. All but two projects in the population were rebated on or after PY 2011 and therefore are subject to Senate Bill (SB) 412 provisions and PBI program requirements. There are 83 PBI projects in the SGIP population representing roughly 40 MW of the 49 MW of total SGIP rebated capacity. All PBI projects are installed at non-residential customer locations. Figure 1-2 summarizes the proportion of PBI and non-PBI projects in the SGIP population by project count and rebated capacity.

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. Review of project data and inspection reports suggests that most SGIP batteries included in this evaluation are two-hour batteries and their inverters are sized at approximately twice the rebated capacity. So, while SGIP AES projects can discharge at the rebated capacity for two hours on average, they are capable of discharging at approximately twice the rebated capacity during hourly or sub-hourly intervals.

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

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: ENERGY STORAGE PROJECTS BY PBI/NON-PBI CLASSIFICATION



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.

Grid integration analysis and optimized dispatch are inherently forward looking metrics that require simulation of storage behavior and modeling of future grid conditions. We employ two distinct approaches to quantify potential benefits of AES. The first is a short-term marginal cost approach using Energy + Environmental Economics' (E3's) Distributed Energy Resource (DER) Avoided Cost Model. In this approach, storage is dispatched based on one of three perspectives: in the customer perspective, storage is dispatched to minimize a customer's monthly electricity bill; in the utility perspective, storage is dispatched to minimize the marginal cost of serving load at the system level; in the carbon minimization perspective, storage is dispatched to minimize carbon emissions for the associated customer.

The second is a 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.

The findings presented in this report are based on a robust sample and found to be statistically significant for non-residential customers representing 96% of the program rebated capacity. Data quality issues prevented a detailed assessment of impacts for residential customers. Thus, the following findings are specific to non-residential AES projects. While residential projects represent an important demographic for the program (residential projects represent the majority of the SGIP energy storage population by project count), these data quality issues are limited to less than 4% of the population rebated capacity and in no way affect the findings presented for non-residential projects. Where possible, we present qualitative metrics that characterize the behavior of residential projects without specifically quantifying performance metrics.

1.3 EVALUATION FINDINGS – OBSERVED 2016 IMPACTS

Evaluation findings for a range of observed impacts are summarized below. Supporting detail is presented in Section 3.

1.3.1 Observed Performance Metrics

The evaluation team examined two key performance metrics of storage systems 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. 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."[3] For purposes of SGIP evaluation, the AES capacity factor is calculated as:

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

The SGIP Handbook requires that PBI projects achieve an AES capacity factor of at least 10% per the above formula, 520 hours 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 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.

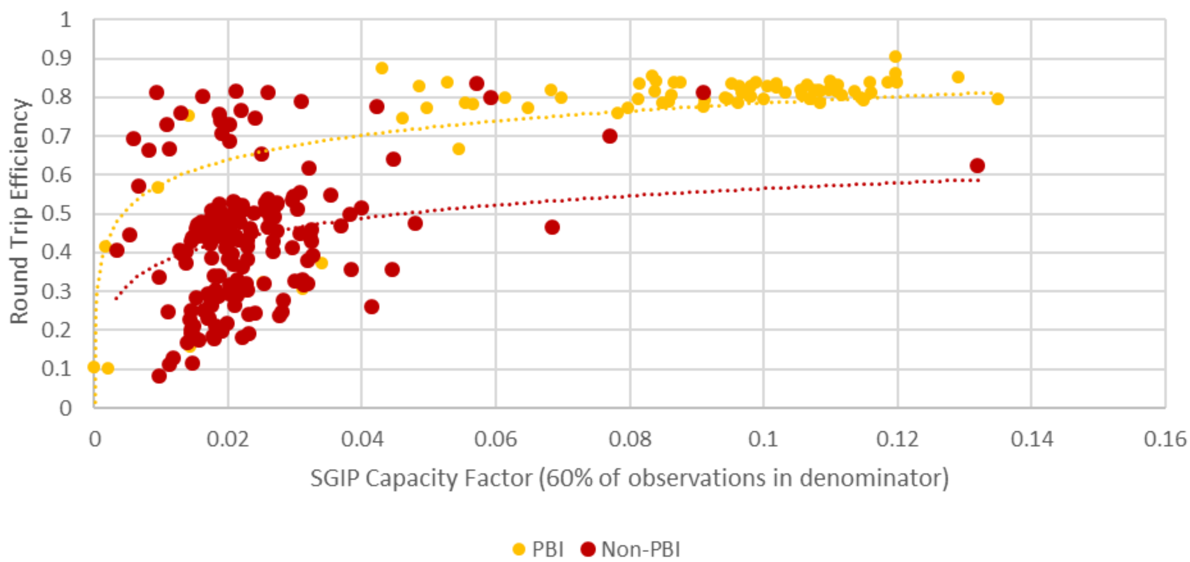
The mean capacity factor was 2.3% for non-PBI projects and 8.1% for PBI projects and the mean observed RTE was 44% for non-PBI projects and 74% for PBI projects over the entire evaluation period. Figure 1-3 displays the project RTEs and CFs. Note that by calculating the RTE over the course of several 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.

3 See 2015 SGIP Handbook, p. 37.

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)

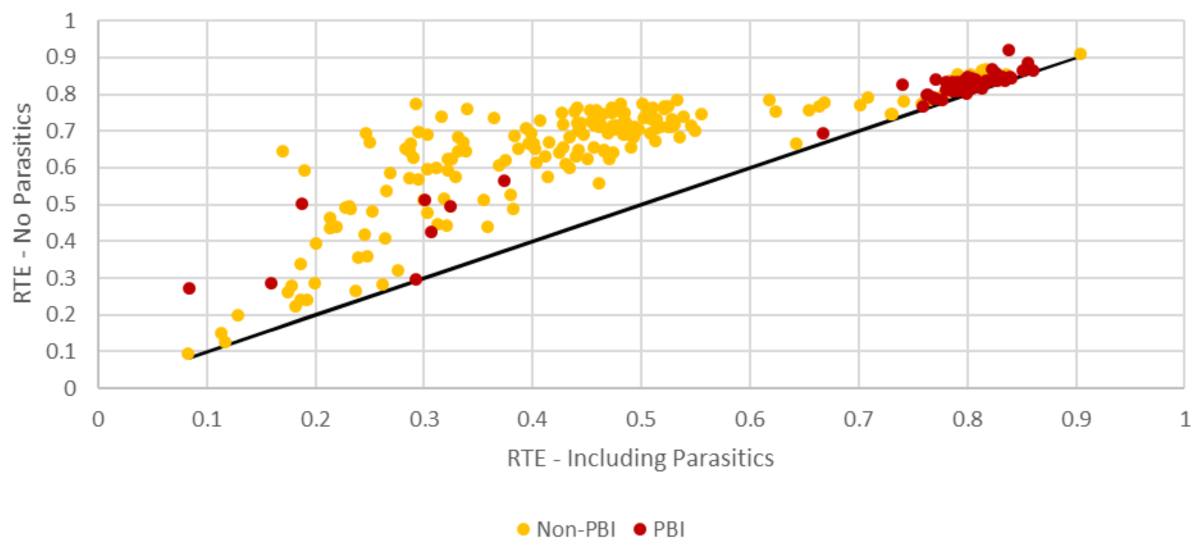
FIGURE 1-3: TOTAL ROUNDTRIP EFFICIENCY VERSUS CAPACITY FACTORS (ALL NONRESIDENTIAL PROJECTS)



The evaluation team observed significant standby losses and parasitic loads associated with system cooling, communications, and other power electronic loads when examining non-PBI 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 of non-residential projects 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 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 red. However, for many of the smaller non-PBI systems – those with RTEs in the 40% to 50% range – removal of the parasitic loads has a substantial impact on the performance of the system. Projects in the 40% to 50% RTE range would exhibit RTEs in the 60% to 80% range if the parasitic loads were removed.

FIGURE 1-4: INFLUENCE OF PARASITICS ON ROUNDTRIP EFFICIENCY



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.[6] Similarly, customers that are also on a rate that assesses demand charges during customer peak demand periods (e.g. non-coincident demand charges) and/or at the monthly billing level may prioritize customer peak demand reduction.

SGIP non-residential projects are generally discharging during peak and partial peak tariff periods when retail energy rates are higher. However, a significant percentage of non-PBI and PBI storage projects are also discharging during off peak tariff hours (Figure 1-5 and Figure 1-6). This behavior suggests that although storage systems are being utilized for some TOU arbitrage, this might not be the main explanation of dispatch behavior.

[6] As discussed in more detail below, the peak periods of many TOU rates in effect in 2016 did not align well with actual system peak demand. Unless otherwise noted, the terms "peak," "partial peak," and "off peak" refer to the periods as defined in the tariffs.

FIGURE 1-5: SGIP NON-RESIDENTIAL NON-PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD

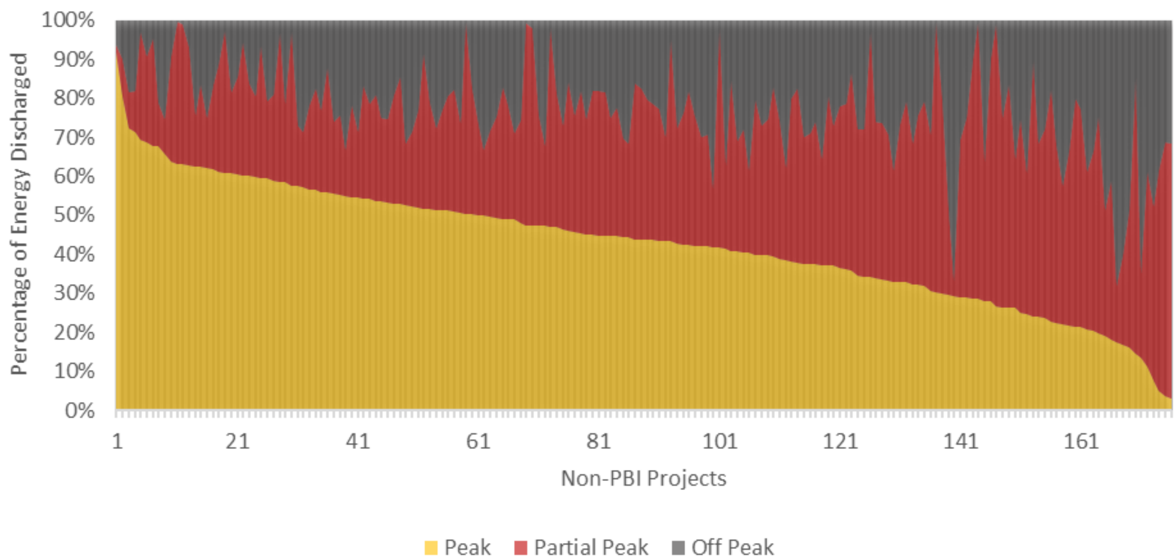
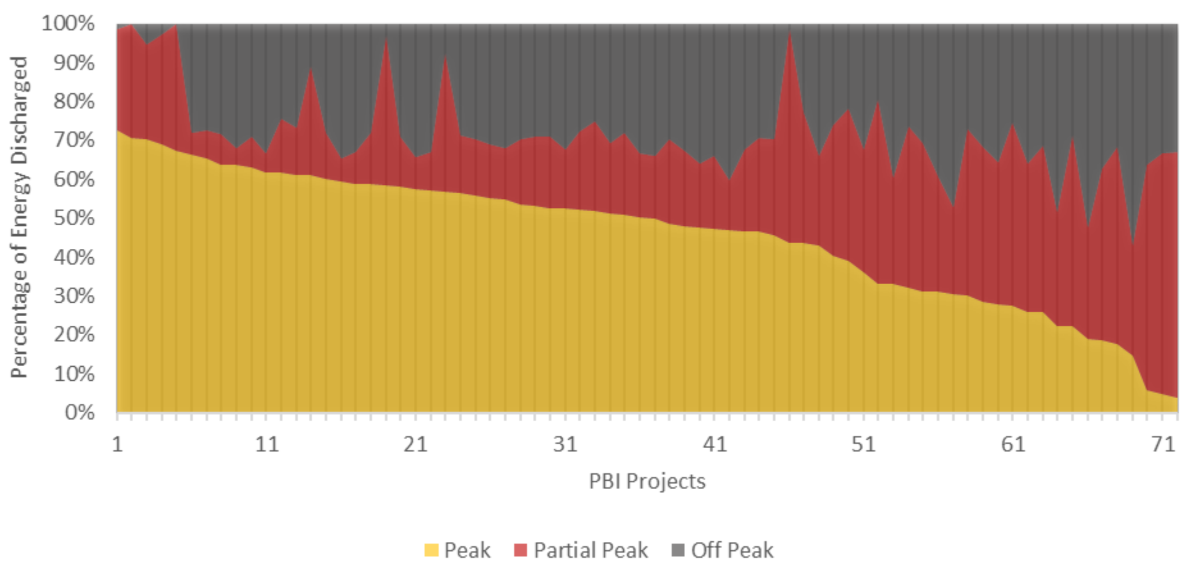


FIGURE 1-6: SGIP NON-RESIDENTIAL PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD



It's important to note that Figure 1-5 and Figure 1-6 represent all sampled projects regardless of customer rate structure. Since a customer on a TOU energy-only rate has no incentive to discharge during off peak TOU periods (when energy rates are lower) and a customer with demand charges would be more incentivized to discharge during peak tariff hours if their peak load was coincident with the TOU peak period, we compared the dispatch behavior for the two rate groups.

Of the 259 projects in the non-residential sample, we obtained rate information for 222 of them. Only nine of those projects were on a TOU energy-only rate (all nine were PBI projects in PG&E territory). We analyzed the extent to which a customer on an energy-only tariff engages in TOU arbitrage compared to customers that incur an additional monthly demand charge. Figure 1-7 presents the average hourly discharge kW per rebated capacity for rates with energy and demand charges and Figure 1-8 presents the same results for TOU energy-only rates. It is important to note that these data are presented in pacific standard time while TOU periods are defined in pacific local time.[7]

FIGURE 1-7: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NON-RESIDENTIAL PROJECTS ON A TOU ENERGY AND DEMAND RATE (PG&E ONLY)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.003	0.005	0.004	0.005	0.005	0.001	0.001	0.002	0.006	0.006	0.003	0.002
1	0.003	0.005	0.005	0.006	0.007	0.002	0.001	0.001	0.004	0.005	0.003	0.002
2	0.002	0.006	0.005	0.006	0.004	0.002	0.001	0.001	0.003	0.005	0.002	0.001
3	0.002	0.005	0.004	0.006	0.004	0.003	0.001	0.002	0.003	0.005	0.002	0.001
4	0.004	0.005	0.004	0.007	0.006	0.006	0.002	0.003	0.005	0.005	0.003	0.001
5	0.004	0.008	0.011	0.011	0.008	0.004	0.007	0.002	0.006	0.006	0.004	0.004
6	0.006	0.027	0.031	0.034	0.024	0.020	0.018	0.021	0.021	0.024	0.022	0.021
7	0.013	0.047	0.044	0.031	0.025	0.021	0.021	0.025	0.022	0.024	0.024	0.021
8	0.009	0.007	0.012	0.015	0.015	0.012	0.011	0.011	0.011	0.011	0.018	0.015
9	0.015	0.015	0.016	0.024	0.022	0.019	0.016	0.018	0.018	0.020	0.034	0.028
10	0.020	0.015	0.019	0.030	0.034	0.031	0.030	0.029	0.028	0.029	0.040	0.030
11	0.021	0.013	0.020	0.037	0.055	0.048	0.047	0.044	0.054	0.055	0.048	0.037
12	0.027	0.017	0.024	0.041	0.061	0.056	0.056	0.058	0.061	0.061	0.042	0.032
13	0.023	0.019	0.026	0.041	0.068	0.070	0.071	0.079	0.082	0.074	0.040	0.032
14	0.025	0.026	0.027	0.038	0.104	0.173	0.155	0.168	0.145	0.100	0.049	0.032
15	0.041	0.030	0.039	0.038	0.125	0.200	0.181	0.206	0.164	0.099	0.055	0.043
16	0.044	0.040	0.055	0.065	0.147	0.210	0.205	0.229	0.174	0.120	0.064	0.058
17	0.065	0.054	0.113	0.157	0.102	0.061	0.077	0.069	0.069	0.130	0.098	0.092
18	0.107	0.096	0.207	0.253	0.170	0.131	0.142	0.126	0.153	0.219	0.162	0.143
19	0.172	0.177	0.256	0.297	0.213	0.165	0.161	0.146	0.183	0.220	0.216	0.215
20	0.193	0.213	0.206	0.174	0.145	0.148	0.135	0.122	0.141	0.142	0.210	0.230
21	0.068	0.079	0.052	0.023	0.027	0.040	0.038	0.042	0.028	0.012	0.095	0.123
22	0.017	0.013	0.034	0.049	0.040	0.042	0.045	0.036	0.041	0.047	0.023	0.018
23	0.047	0.036	0.020	0.007	0.005	0.002	0.003	0.001	0.004	0.004	0.041	0.057

7 These data are presented in standard time, whereas TOU periods are presented in local time. TOU time periods begin and end one hour later during daylight savings time which occurred between 3/13 and 11/6 in 2016. The PG&E peak energy TOU period goes from 11 am to 4 pm PST inclusive. See Section 3 for a break-out of TOU periods by season and time of day.

FIGURE 1-8: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NON-RESIDENTIAL PROJECTS ON A TOU ENERGY-ONLY RATE (PG&E ONLY)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.007	0.002	0.001	0.001	0.001	0.002	0.002	0.001	0.000	0.002	0.002	0.001
1	0.004	0.001	0.001	0.001	0.001	0.004	0.003	0.001	0.001	0.001	0.001	0.002
2	0.004	0.001	0.001	0.001	0.000	0.001	0.002	0.000	0.001	0.000	0.002	0.001
3	0.003	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.002	0.001
4	0.002	0.001	0.001	0.002	0.005	0.004	0.004	0.002	0.008	0.004	0.003	0.003
5	0.019	0.001	0.003	0.007	0.016	0.013	0.006	0.004	0.015	0.011	0.008	0.008
6	0.044	0.001	0.009	0.009	0.035	0.027	0.016	0.011	0.014	0.018	0.022	0.029
7	0.058	0.014	0.039	0.080	0.074	0.058	0.059	0.041	0.041	0.043	0.042	0.018
8	0.076	0.051	0.044	0.095	0.047	0.048	0.046	0.017	0.026	0.031	0.059	0.036
9	0.127	0.168	0.087	0.154	0.061	0.083	0.081	0.032	0.035	0.043	0.149	0.120
10	0.074	0.161	0.069	0.098	0.064	0.076	0.062	0.047	0.037	0.031	0.122	0.122
11	0.026	0.135	0.075	0.106	0.176	0.261	0.191	0.187	0.181	0.174	0.104	0.127
12	0.043	0.082	0.079	0.071	0.149	0.253	0.204	0.192	0.180	0.177	0.091	0.081
13	0.076	0.035	0.050	0.047	0.113	0.201	0.180	0.173	0.139	0.127	0.062	0.067
14	0.067	0.020	0.030	0.039	0.142	0.149	0.148	0.161	0.123	0.128	0.062	0.065
15	0.035	0.022	0.019	0.028	0.122	0.096	0.097	0.092	0.089	0.116	0.062	0.047
16	0.032	0.026	0.023	0.017	0.119	0.068	0.079	0.078	0.071	0.122	0.055	0.034
17	0.033	0.025	0.045	0.039	0.034	0.023	0.025	0.022	0.048	0.062	0.045	0.023
18	0.069	0.050	0.104	0.078	0.047	0.092	0.076	0.078	0.103	0.134	0.065	0.028
19	0.102	0.092	0.109	0.089	0.053	0.098	0.088	0.090	0.109	0.144	0.152	0.082
20	0.111	0.090	0.080	0.057	0.044	0.072	0.054	0.055	0.069	0.094	0.166	0.103
21	0.047	0.036	0.021	0.004	0.007	0.004	0.007	0.004	0.007	0.004	0.054	0.043
22	0.008	0.004	0.010	0.008	0.009	0.008	0.009	0.006	0.007	0.009	0.008	0.002
23	0.036	0.018	0.008	0.001	0.001	0.005	0.003	0.001	0.001	0.002	0.006	0.014

For PBI projects with demand charges there is a clear signature of discharge during both seasons – winter and summer. During summer months, average net discharge increases substantially beginning in the early afternoon (2 to 3 pm) and ebbs in the late evening beginning around 10 pm. The early evening discharge is more substantial during the winter months.

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 12 pm to 5pm local time, which coincides with the peak period as defined in the tariff. These data suggest that customers on TOU energy only rates are optimizing their bill savings with TOU arbitrage.

Customers that are on a rate that assigns demand charges during peak demand periods (as defined by tariffs) and/or at the monthly billing level (also referred to as non-coincident demand charges) may prioritize peak demand reduction. The evaluation team examined the impact of storage discharge on monthly, or non-coincident, demand.

Figure 1-9 shows the percentage of 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 1-9 shows that during all months most PBI and non-PBI projects are reducing customer peak demand. Non-PBI projects reduce peak demand (by any amount) more often than PBI projects.

FIGURE 1-9: MONTHLY PEAK DEMAND FOR NON-RESIDENTIAL PROJECTS

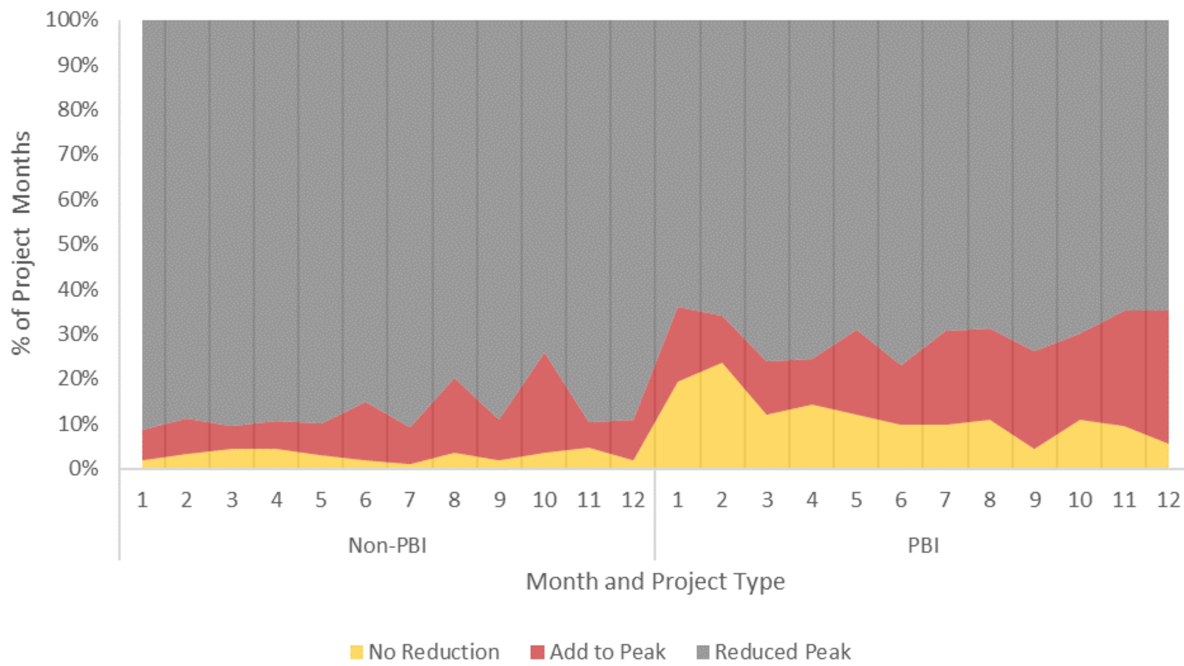
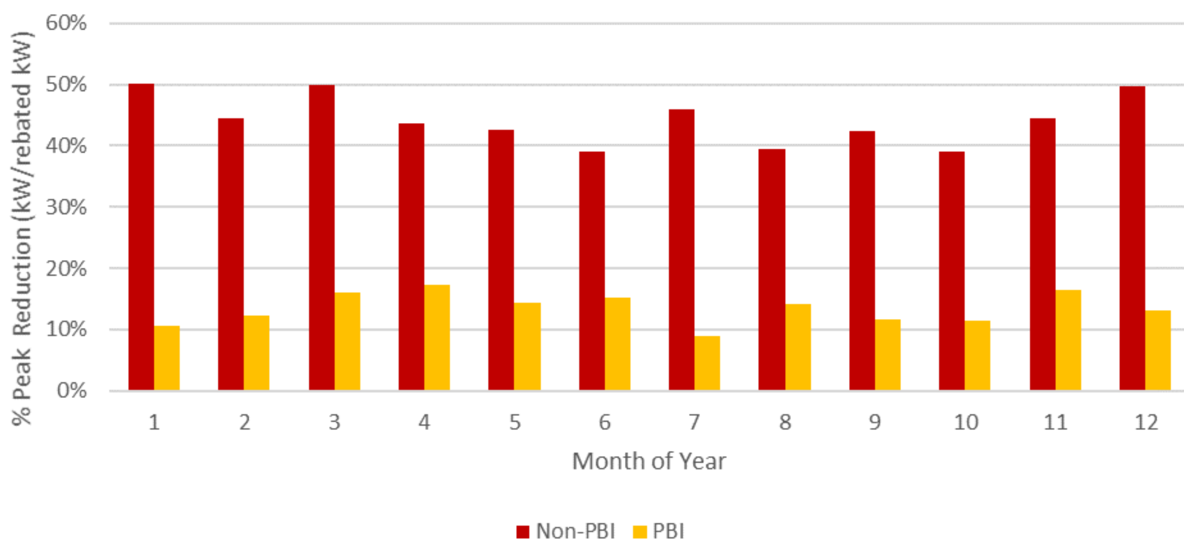


Figure 1-10 below shows the magnitude of average monthly customer peak demand reductions normalized by SGIP rebated capacity.

FIGURE 1-10: MONTHLY CUSTOMER PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)



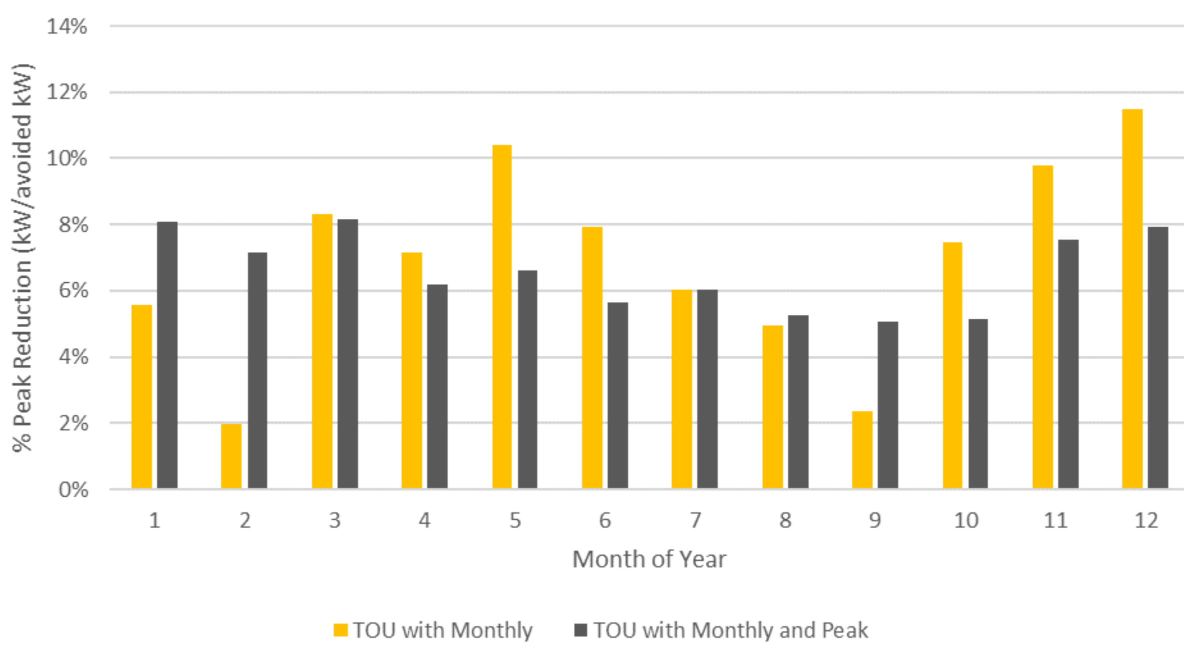
A value of 100% would indicate that a 1 MW AES project reduces a customer's monthly peak demand by 1 MW. Non-PBI projects reduced monthly customer peak demand by approximately 44% of their rebated capacity over the course of the year. In contrast, larger PBI projects reduced monthly customer peak demand by approximately 13% 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, non-residential SGIP AES projects reduced customer summer peak demand by 1,919 kW during 2016 (approximately 4% of SGIP AES rebated capacity).

We also compared monthly demand reduction based on the rate type for each of the customers. Customers on 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 1-11 and Figure 1-12 present the monthly peak demand reduction for PBI and non-PBI customers, respectively, by rate type. The vertical axis represents the percentage reduction in monthly peak demand realized from the storage system. 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%. For non-PBI projects, there is some variation in demand reduction for customers on monthly-only demand charges compared to those on a monthly combined with peak demand charge, but they only represent five of the 151 customers within that group. The PBI projects on a TOU energy-only rate provide more perspective. Throughout several months of the year, they are increasing their monthly 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 1-11: PBI MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) BY RATE GROUP

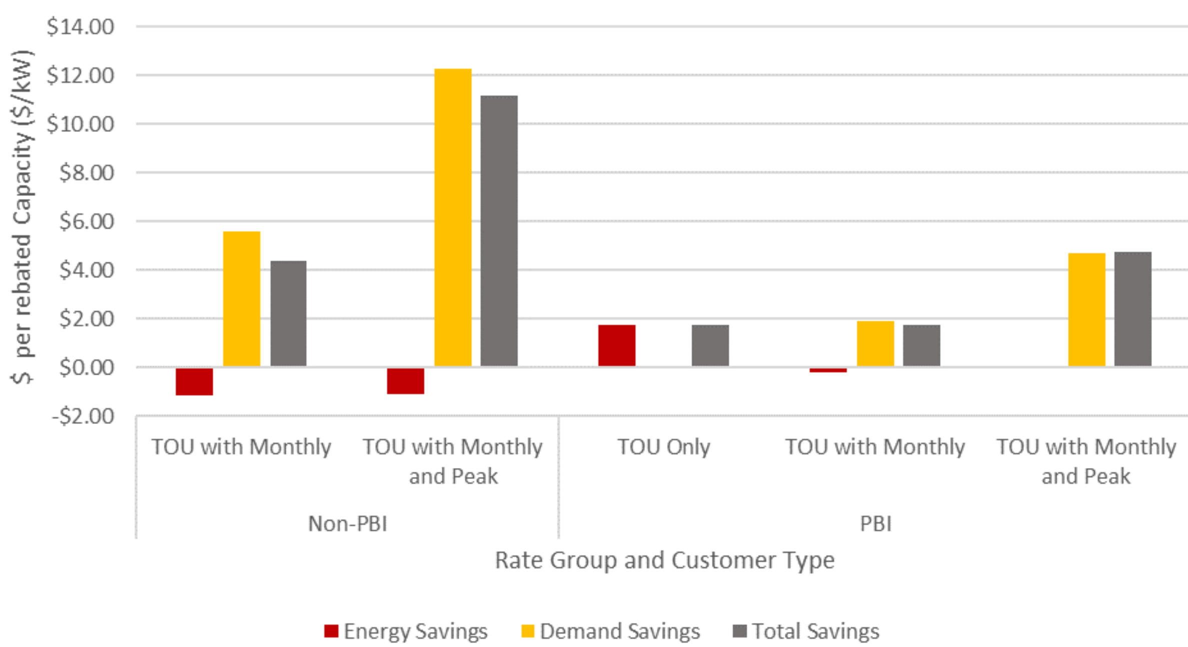
FIGURE 1-12: NON-PBI MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) BY RATE GROUP



Finally, 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 1-13 presents those results for PBI and non-PBI projects by rate type. The vertical axis represents the average monthly savings (or cost) in dollars, normalized by SGIP rebated capacity.

For both non-PBI rate types, customers incurred energy costs, on average, by utilizing their storage systems. However, both groups realized more significant savings by optimizing their storage to reduce peak and/or monthly demand charges. PBI projects on a TOU energy-only rate realized savings on energy charges 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 1-13: CUSTOMER BILL SAVINGS (S/KW) BY RATE GROUP AND PBI/NON-PBI



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.

There are significant differences between the PBI and non-PBI projects when examining charge and discharge (kW) on an average hourly basis. Figure 1-14 and Figure 1-15 present the findings for PBI projects. Discharging is positive and is shown in green and charging is negative and is shown in red.

FIGURE 1-14: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.004	0.004	0.003	0.004	0.004	0.001	0.001	0.002	0.005	0.005	0.003	0.002
1	0.003	0.004	0.004	0.005	0.006	0.002	0.001	0.001	0.004	0.004	0.003	0.002
2	0.002	0.005	0.004	0.005	0.003	0.002	0.001	0.001	0.003	0.004	0.002	0.001
3	0.002	0.004	0.003	0.005	0.003	0.003	0.001	0.002	0.003	0.005	0.002	0.001
4	0.003	0.004	0.004	0.006	0.006	0.005	0.002	0.003	0.005	0.005	0.003	0.001
5	0.006	0.006	0.009	0.010	0.009	0.005	0.006	0.003	0.007	0.006	0.004	0.004
6	0.012	0.022	0.026	0.029	0.025	0.020	0.017	0.019	0.020	0.023	0.021	0.021
7	0.019	0.040	0.041	0.037	0.031	0.025	0.025	0.026	0.023	0.025	0.025	0.021
8	0.020	0.014	0.017	0.030	0.020	0.017	0.016	0.012	0.013	0.014	0.024	0.020
9	0.031	0.034	0.025	0.044	0.026	0.027	0.024	0.019	0.020	0.022	0.046	0.038
10	0.026	0.033	0.025	0.039	0.037	0.035	0.033	0.031	0.029	0.029	0.048	0.040
11	0.020	0.028	0.026	0.046	0.069	0.073	0.065	0.061	0.067	0.067	0.053	0.046
12	0.027	0.025	0.030	0.044	0.071	0.079	0.074	0.074	0.073	0.073	0.046	0.036
13	0.029	0.020	0.028	0.040	0.072	0.084	0.083	0.089	0.086	0.078	0.041	0.034
14	0.029	0.023	0.026	0.036	0.106	0.164	0.149	0.162	0.138	0.100	0.049	0.034
15	0.037	0.027	0.034	0.035	0.120	0.180	0.163	0.183	0.150	0.098	0.054	0.041
16	0.039	0.036	0.048	0.054	0.138	0.184	0.181	0.201	0.156	0.116	0.061	0.052
17	0.056	0.047	0.098	0.130	0.089	0.054	0.067	0.061	0.064	0.117	0.088	0.080
18	0.094	0.084	0.181	0.213	0.146	0.121	0.128	0.115	0.142	0.202	0.143	0.123
19	0.149	0.155	0.221	0.249	0.183	0.151	0.146	0.134	0.168	0.203	0.199	0.189
20	0.166	0.183	0.176	0.147	0.125	0.133	0.119	0.108	0.128	0.132	0.196	0.204
21	0.060	0.068	0.045	0.019	0.023	0.033	0.031	0.034	0.024	0.010	0.086	0.106
22	0.014	0.011	0.029	0.040	0.034	0.036	0.039	0.031	0.036	0.041	0.020	0.016
23	0.042	0.032	0.017	0.006	0.005	0.003	0.003	0.001	0.003	0.004	0.036	0.049

FIGURE 1-15: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) BY MONTH FOR PBI PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.174	-0.171	-0.194	-0.190	-0.216	-0.264	-0.260	-0.257	-0.251	-0.234	-0.239	-0.236
1	-0.154	-0.143	-0.153	-0.145	-0.156	-0.182	-0.188	-0.186	-0.182	-0.154	-0.210	-0.201
2	-0.107	-0.103	-0.105	-0.102	-0.116	-0.114	-0.101	-0.097	-0.104	-0.098	-0.150	-0.144
3	-0.060	-0.063	-0.068	-0.070	-0.083	-0.074	-0.063	-0.050	-0.059	-0.064	-0.100	-0.108
4	-0.050	-0.045	-0.053	-0.050	-0.061	-0.053	-0.045	-0.031	-0.035	-0.041	-0.063	-0.072
5	-0.038	-0.031	-0.043	-0.040	-0.044	-0.037	-0.034	-0.024	-0.023	-0.029	-0.042	-0.050
6	-0.027	-0.024	-0.035	-0.035	-0.032	-0.025	-0.026	-0.018	-0.018	-0.022	-0.029	-0.032
7	-0.022	-0.022	-0.026	-0.026	-0.022	-0.020	-0.019	-0.014	-0.017	-0.016	-0.022	-0.023
8	-0.015	-0.029	-0.028	-0.029	-0.021	-0.019	-0.019	-0.020	-0.017	-0.018	-0.023	-0.021
9	-0.021	-0.038	-0.039	-0.040	-0.032	-0.025	-0.027	-0.028	-0.025	-0.026	-0.032	-0.031
10	-0.022	-0.025	-0.029	-0.031	-0.027	-0.027	-0.021	-0.022	-0.023	-0.024	-0.029	-0.028
11	-0.024	-0.022	-0.022	-0.022	-0.019	-0.010	-0.011	-0.012	-0.014	-0.020	-0.023	-0.021
12	-0.015	-0.017	-0.020	-0.022	-0.014	-0.010	-0.008	-0.008	-0.011	-0.017	-0.019	-0.019
13	-0.014	-0.016	-0.018	-0.020	-0.011	-0.012	-0.008	-0.009	-0.011	-0.016	-0.017	-0.017
14	-0.020	-0.014	-0.018	-0.017	-0.012	-0.019	-0.019	-0.015	-0.018	-0.021	-0.015	-0.013
15	-0.020	-0.014	-0.018	-0.018	-0.011	-0.020	-0.018	-0.014	-0.017	-0.017	-0.014	-0.010
16	-0.019	-0.013	-0.017	-0.019	-0.010	-0.011	-0.010	-0.011	-0.015	-0.014	-0.011	-0.011
17	-0.014	-0.011	-0.014	-0.015	-0.012	-0.019	-0.021	-0.026	-0.026	-0.021	-0.011	-0.011
18	-0.014	-0.014	-0.015	-0.014	-0.011	-0.011	-0.011	-0.013	-0.014	-0.015	-0.018	-0.014
19	-0.011	-0.012	-0.019	-0.015	-0.009	-0.009	-0.010	-0.012	-0.012	-0.016	-0.019	-0.013
20	-0.022	-0.013	-0.033	-0.051	-0.055	-0.043	-0.041	-0.048	-0.043	-0.062	-0.027	-0.016
21	-0.035	-0.034	-0.069	-0.122	-0.144	-0.136	-0.138	-0.135	-0.135	-0.171	-0.052	-0.034
22	-0.130	-0.146	-0.137	-0.163	-0.189	-0.231	-0.210	-0.227	-0.211	-0.193	-0.172	-0.181
23	-0.078	-0.107	-0.175	-0.230	-0.269	-0.317	-0.304	-0.306	-0.289	-0.278	-0.172	-0.155

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 1-16 and Figure 1-17 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 non-PBI systems are being utilized to perform peak demand shaving at the expense of TOU arbitrage.

FIGURE 1-16: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.082	0.055	0.034	0.014	0.027	0.047	0.042	0.048	0.052	0.048	0.034	0.042
1	0.048	0.033	0.034	0.008	0.010	0.018	0.005	0.007	0.008	0.007	0.042	0.038
2	0.051	0.030	0.020	0.007	0.011	0.010	0.005	0.007	0.008	0.005	0.007	0.013
3	0.028	0.023	0.018	0.004	0.012	0.009	0.005	0.007	0.007	0.009	0.005	0.014
4	0.022	0.015	0.022	0.015	0.021	0.017	0.013	0.010	0.009	0.013	0.009	0.017
5	0.026	0.023	0.031	0.027	0.029	0.025	0.021	0.024	0.031	0.029	0.022	0.029
6	0.062	0.048	0.047	0.037	0.041	0.038	0.036	0.038	0.027	0.025	0.037	0.044
7	0.067	0.056	0.060	0.056	0.063	0.068	0.062	0.068	0.057	0.046	0.051	0.050
8	0.067	0.055	0.056	0.045	0.057	0.061	0.055	0.047	0.043	0.035	0.048	0.050
9	0.071	0.068	0.060	0.063	0.070	0.077	0.067	0.058	0.066	0.052	0.060	0.043
10	0.070	0.059	0.066	0.064	0.076	0.100	0.083	0.073	0.089	0.062	0.065	0.040
11	0.063	0.067	0.068	0.058	0.076	0.102	0.077	0.074	0.093	0.062	0.064	0.036
12	0.073	0.067	0.063	0.065	0.073	0.092	0.079	0.070	0.078	0.061	0.073	0.045
13	0.073	0.080	0.070	0.064	0.074	0.088	0.072	0.068	0.076	0.063	0.066	0.036
14	0.060	0.081	0.069	0.060	0.071	0.081	0.072	0.077	0.076	0.061	0.060	0.029
15	0.055	0.068	0.065	0.062	0.072	0.082	0.079	0.103	0.072	0.060	0.053	0.034
16	0.054	0.060	0.074	0.095	0.079	0.083	0.100	0.076	0.093	0.053	0.070	0.046
17	0.110	0.100	0.066	0.071	0.057	0.072	0.072	0.061	0.068	0.045	0.093	0.074
18	0.101	0.112	0.098	0.094	0.061	0.074	0.064	0.064	0.078	0.061	0.089	0.078
19	0.089	0.097	0.102	0.096	0.085	0.079	0.065	0.071	0.064	0.055	0.078	0.072
20	0.073	0.076	0.078	0.073	0.081	0.074	0.063	0.055	0.049	0.042	0.059	0.056
21	0.042	0.042	0.036	0.030	0.033	0.030	0.028	0.020	0.018	0.016	0.033	0.040
22	0.036	0.030	0.024	0.016	0.017	0.026	0.015	0.012	0.013	0.009	0.021	0.033
23	0.018	0.014	0.032	0.053	0.041	0.054	0.039	0.035	0.045	0.039	0.016	0.022

FIGURE 1-17: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.031	-0.035	-0.039	-0.038	-0.039	-0.044	-0.035	-0.034	-0.037	-0.035	-0.037	-0.038
1	-0.031	-0.032	-0.029	-0.028	-0.028	-0.030	-0.027	-0.027	-0.029	-0.027	-0.034	-0.039
2	-0.027	-0.027	-0.024	-0.024	-0.023	-0.024	-0.022	-0.022	-0.023	-0.022	-0.026	-0.030
3	-0.023	-0.022	-0.022	-0.022	-0.023	-0.022	-0.022	-0.022	-0.023	-0.021	-0.023	-0.024
4	-0.023	-0.022	-0.021	-0.022	-0.022	-0.022	-0.021	-0.022	-0.022	-0.021	-0.022	-0.021
5	-0.021	-0.020	-0.022	-0.022	-0.022	-0.023	-0.022	-0.023	-0.024	-0.022	-0.021	-0.021
6	-0.022	-0.022	-0.024	-0.023	-0.024	-0.025	-0.022	-0.023	-0.024	-0.023	-0.022	-0.022
7	-0.029	-0.026	-0.026	-0.025	-0.026	-0.029	-0.025	-0.026	-0.026	-0.024	-0.025	-0.027
8	-0.023	-0.022	-0.024	-0.022	-0.024	-0.023	-0.022	-0.022	-0.022	-0.020	-0.023	-0.027
9	-0.035	-0.031	-0.036	-0.035	-0.041	-0.043	-0.039	-0.037	-0.031	-0.027	-0.033	-0.036
10	-0.050	-0.043	-0.038	-0.038	-0.042	-0.046	-0.040	-0.039	-0.035	-0.028	-0.034	-0.035
11	-0.049	-0.045	-0.039	-0.034	-0.043	-0.043	-0.043	-0.040	-0.039	-0.031	-0.036	-0.034
12	-0.045	-0.038	-0.037	-0.034	-0.040	-0.047	-0.040	-0.039	-0.041	-0.032	-0.036	-0.033
13	-0.038	-0.035	-0.036	-0.034	-0.041	-0.049	-0.043	-0.039	-0.041	-0.033	-0.037	-0.030
14	-0.038	-0.037	-0.038	-0.037	-0.046	-0.052	-0.047	-0.045	-0.043	-0.035	-0.039	-0.029
15	-0.037	-0.040	-0.038	-0.037	-0.048	-0.051	-0.049	-0.047	-0.045	-0.039	-0.043	-0.028
16	-0.034	-0.045	-0.042	-0.039	-0.048	-0.058	-0.049	-0.061	-0.049	-0.044	-0.043	-0.028
17	-0.034	-0.043	-0.041	-0.044	-0.057	-0.070	-0.069	-0.064	-0.067	-0.043	-0.037	-0.026
18	-0.040	-0.045	-0.042	-0.046	-0.051	-0.069	-0.063	-0.048	-0.047	-0.037	-0.047	-0.034
19	-0.048	-0.053	-0.054	-0.057	-0.044	-0.058	-0.051	-0.040	-0.045	-0.038	-0.056	-0.039
20	-0.067	-0.064	-0.049	-0.049	-0.054	-0.059	-0.047	-0.045	-0.049	-0.047	-0.061	-0.046
21	-0.050	-0.047	-0.043	-0.042	-0.047	-0.044	-0.045	-0.035	-0.037	-0.032	-0.041	-0.033
22	-0.046	-0.051	-0.055	-0.050	-0.058	-0.056	-0.050	-0.040	-0.044	-0.037	-0.050	-0.043
23	-0.040	-0.043	-0.048	-0.042	-0.045	-0.048	-0.038	-0.034	-0.037	-0.033	-0.045	-0.041

1.3.4 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 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 from our sample of non-residential projects and comparing that to the top 200 peak demand hours throughout 2016 for the CAISO system.

FIGURE 1-18: NON-RESIDENTIAL NET DISCHARGE KWH PER REBATED CAPACITY (KW) DURING CAISO TOP HOURS

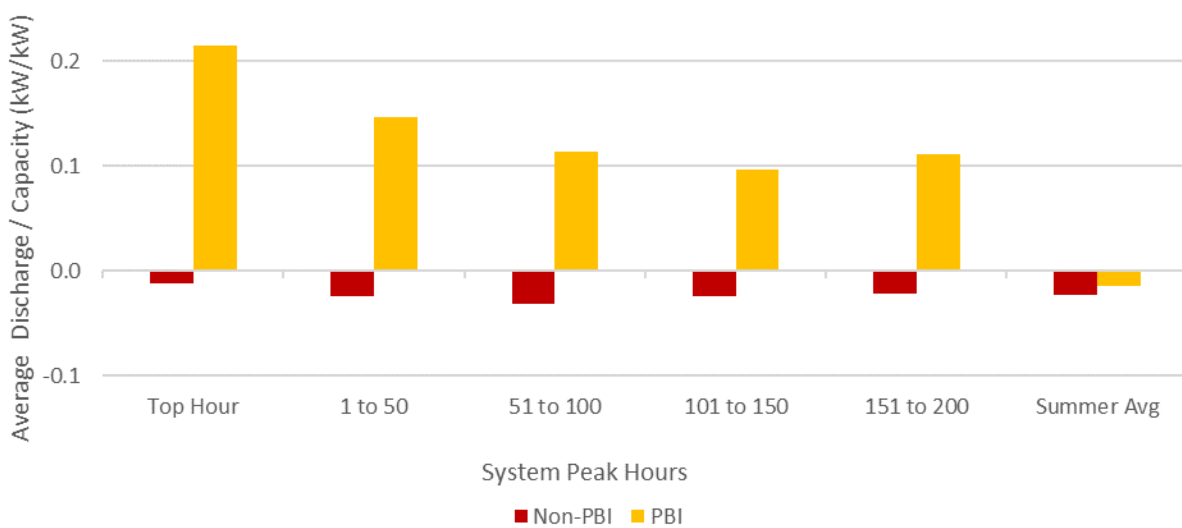


Figure 1-18 presents the average net electric energy discharge (kWh per kW rebated capacity) for non-PBI and PBI projects for different bins of top hours along with the summer average (defined as June through September inclusive). During 2016 the CAISO statewide system load peaked at 45,981 MW on July 27 during the hour from 4 to 5 PM PDT. While PBI projects delivered a CAISO system peak demand reduction approaching 9 MW during the top hour (representing 22% of the 40.5 MW of rebated PBI capacity), non-PBI projects were net consumers of electricity during this hour. The average impact of SGIP AES projects (PBI and non-PBI) across the CAISO top 200 load hours is a reduction of 5,416 kW.

SGIP storage projects also provide system benefits by participating in demand response (DR) programs. The evaluation team assessed participation of SGIP projects in two utility DR programs: a supply side program that encourages demand reduction (e.g., storage discharge), and an excess supply program that promotes increased load (e.g., storage charge). There were a total of 22 event hours between PBI and non-PBI projects which resulted in net discharging of roughly 13,700 kWh. The project that participated in the excess supply program absorbed roughly 4,500 kWh during the six event hours.

TABLE 1-1: SGIP AES PARTICIPATION IN DEMAND RESPONSE PROGRAMS

Project Type	Demand Response Event	n Hours Awarded	Total Rebated Capacity kW	Net Discharge/Charge kWh during Events
PBI	Supply Side	18	882	13,602
	Excess Supply Side	6	90	-4,475
Non-PBI	Supply Side	4	81	68

SGIP projects participated in other DR programs but event information for those DR auction mechanisms was not made available to the evaluation team.

1.3.5 TOU Rates and Marginal Costs

The modest system peak load impacts observed for PBI systems (9 – 22% of rebated capacity as shown in Figure 1-18) and net peak load increase for non-PBI systems illustrates how customer rates are not closely aligned with system loads and marginal costs. CPUC avoided costs developed for DERs represent the marginal cost of delivering energy in each hour, including an allocation of system, transmission, and distribution capacity costs to peak load hours (See Section 4.2.1). Figure 1-19 shows the average hourly CPUC avoided costs for DERs overlayed with the SCE TOU periods in 2016. Figure 1-20 shows revised TOU periods proposed by SCE in the CPUC Residential Rate Reform Proceeding and CPUC avoided costs for 2030, reflecting higher penetrations of renewable generation.[8]

[8] CPUC Rulemaking 12-06-013

FIGURE 1-19: 2016 SCE TOU PERIODS AND AVERAGE HOURLY CPUC AVOIDED COSTS FOR DERS IN 2016 (PACIFIC LOCAL TIME, HOUR ENDING)[9]

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
1	$43	$41	$33	$38	$38	$39	$42	$44	$45	$47	$52	$53
2	$42	$39	$32	$36	$37	$38	$41	$42	$43	$45	$51	$52
3	$41	$38	$31	$35	$36	$38	$40	$41	$42	$44	$50	$51
4	$41	$38	$32	$37	$37	$38	$40	$42	$43	$46	$51	$52
5	$42	$40	$35	$43	$41	$40	$42	$44	$46	$49	$54	$54
6	$47	$46	$40	$48	$43	$42	$42	$46	$48	$53	$60	$62
7	$51	$49	$42	$46	$40	$41	$42	$46	$48	$54	$65	$69
8	$52	$49	$38	$37	$33	$38	$42	$44	$46	$50	$59	$71
9	$47	$45	$33	$30	$29	$40	$43	$45	$46	$47	$51	$59
10	$44	$41	$31	$29	$30	$41	$44	$46	$47	$48	$48	$53
11	$44	$40	$31	$31	$30	$43	$45	$48	$49	$49	$47	$48
12	$43	$39	$31	$32	$31	$45	$48	$51	$51	$51	$48	$47
13	$42	$39	$31	$32	$30	$46	$51	$53	$53	$52	$47	$46
14	$41	$38	$32	$32	$31	$48	$53	$77	$538	$54	$47	$46
15	$42	$39	$32	$33	$31	$50	$56	$289	$910	$58	$49	$47
16	$44	$41	$35	$36	$34	$54	$60	$530	$1,266	$72	$52	$55
17	$55	$46	$40	$41	$38	$55	$60	$596	$1,166	$72	$65	$67
18	$66	$56	$46	$50	$46	$60	$61	$331	$1,899	$87	$85	$87
19	$66	$65	$54	$58	$52	$62	$62	$521	$1,175	$76	$77	$84
20	$61	$58	$50	$62	$59	$60	$60	$157	$327	$65	$68	$76
21	$58	$56	$45	$53	$53	$54	$56	$55	$55	$58	$65	$72
22	$54	$51	$41	$48	$46	$48	$51	$52	$51	$55	$60	$66
23	$50	$47	$38	$43	$42	$44	$48	$48	$49	$52	$57	$62
24	$46	$44	$34	$41	$39	$41	$45	$46	$47	$48	$52	$57

Super Off Peak

Off Peak

On Peak

Super Off Peak

There are two key challenges for TOU rates with respect to incentivising AES dispach. The first is properly aligning the TOU periods for peak loads net of PV generation that are occuring later in the evening. The second challenge, with respect to AES, is that 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.

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

FIGURE 1-20: PROPOSED SCE TOU PERIODS AND AVERAGE HOURLY CPUC AVOIDED COSTS FOR DER IN 2030 (PACIFIC LOCAL TIME, HOUR ENDING) [10]

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
1	$105	$106	$98	$100	$97	$97	$100	$103	$101	$107	$116	$112
2	$102	$101	$95	$95	$93	$95	$98	$95	$97	$102	$113	$110
3	$100	$99	$94	$93	$90	$93	$95	$93	$95	$101	$111	$107
4	$100	$97	$98	$99	$94	$94	$96	$94	$97	$104	$113	$109
5	$104	$102	$108	$118	$105	$100	$100	$102	$106	$113	$119	$114
6	$117	$123	$127	$134	$111	$105	$102	$108	$112	$122	$135	$128
7	$128	$131	$137	$126	$102	$102	$101	$107	$112	$124	$144	$148
8	$129	$132	$120	$97	$14	$95	$99	$99	$103	$113	$129	$152
9	$118	$119	$100	$14	$14	$99	$102	$101	$103	$108	$113	$122
10	$109	$106	$14	$14	$14	$15	$106	$107	$107	$110	$105	$111
11	$107	$102	$14	$14	$14	$18	$110	$112	$113	$115	$102	$99
12	$105	$101	$14	$15	$15	$22	$114	$118	$117	$118	$105	$98
13	$102	$99	$14	$15	$15	$24	$121	$124	$123	$121	$102	$95
14	$100	$99	$15	$17	$15	$29	$129	$132	$133	$126	$103	$95
15	$102	$101	$15	$17	$15	$33	$137	$138	$306	$135	$107	$98
16	$110	$107	$108	$18	$16	$142	$147	$154	$1,347	$145	$115	$112
17	$135	$122	$127	$112	$17	$145	$151	$576	$2,883	$239	$146	$144
18	$171	$154	$152	$139	$121	$158	$154	$501	$2,851	$214	$195	$189
19	$172	$182	$183	$165	$139	$162	$153	$664	$1,584	$185	$177	$183
20	$156	$160	$166	$174	$160	$160	$147	$256	$520	$154	$155	$164
21	$150	$152	$146	$150	$141	$142	$137	$126	$130	$138	$147	$152
22	$133	$137	$131	$132	$122	$121	$126	$122	$121	$129	$134	$142
23	$124	$123	$118	$118	$108	$113	$112	$116	$117	$117	$125	$133
24	$114	$116	$103	$110	$101	$104	$105	$108	$109	$110	$116	$120

Modifying TOU periods to account for excess solar generation during the day and peak net loads that occur later in the evening is under active consideration in the CPUC Residential Rate Reform Proceeding. Shifting the TOU period to later in the day will capture more of the high system marginal costs hours (e.g., hour ending (HE) 19 and HE 20 in August and September) that fall outside the current on-peak TOU period. SCE has also proposed a super off-peak period in the winter between HE 9 and HE 16 when excess renewable generation is most likely to occur.

Broad TOU rate periods, however, do not harness the potential for highly flexible resources like AES to support the grid during those specific hours with the highest marginal costs. Figure 1-20 shows an example PG&E TOU rate (E19S) compared to the 2016 CPUC avoided costs in Fresno for three summer days.

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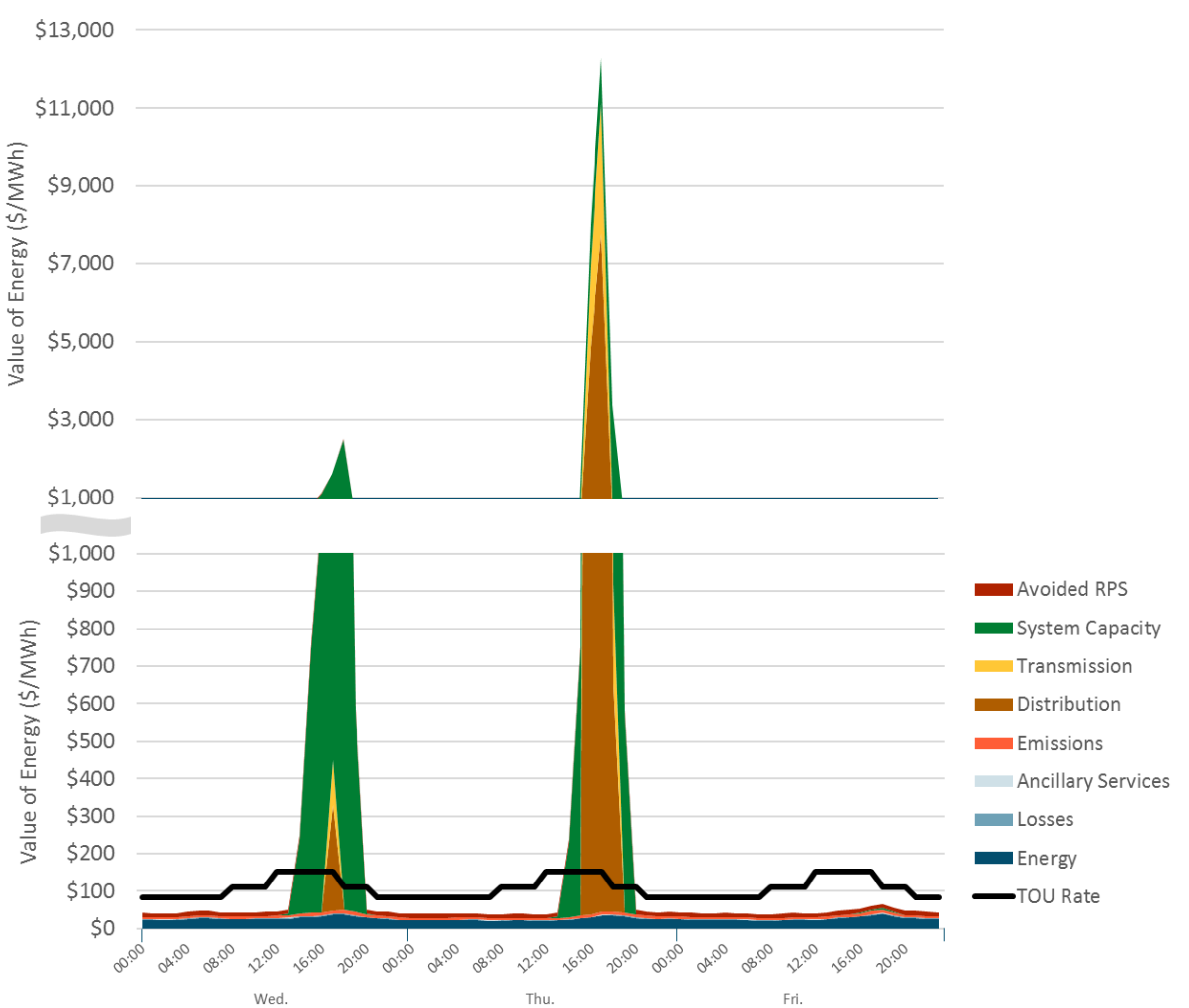
[10] 2030 CPUC avoided costs for climate zone 9: Burbank-Glendale

FIGURE 1-21: THREE DAY SNAPSHOT OF PG&E TOU RATES AND CPUC AVOIDED COSTS IN 2016[11]



On the first day, high system capacity value is concentrated in the three hours between 5 and 8 PM, but the TOU rate provides an equal incentive for AES to discharge beginning at noon. The next day, local transmission and distribution capacity costs drive a significantly higher value concentrated between 4 and 6 PM. Focusing AES discharge in just those two hours based on local system conditions would maximize the value to the grid. For the last day, the difference between on- and off-peak marginal costs is relatively small. Charging AES off-peak and discharging on-peak reduces the customer bill, but provides limited value to the grid on this particular day.

[11] Climate Zone 13 – Fresno and PG&E E19S Rate

1.3.6 Observed Greenhouse Gas Impacts

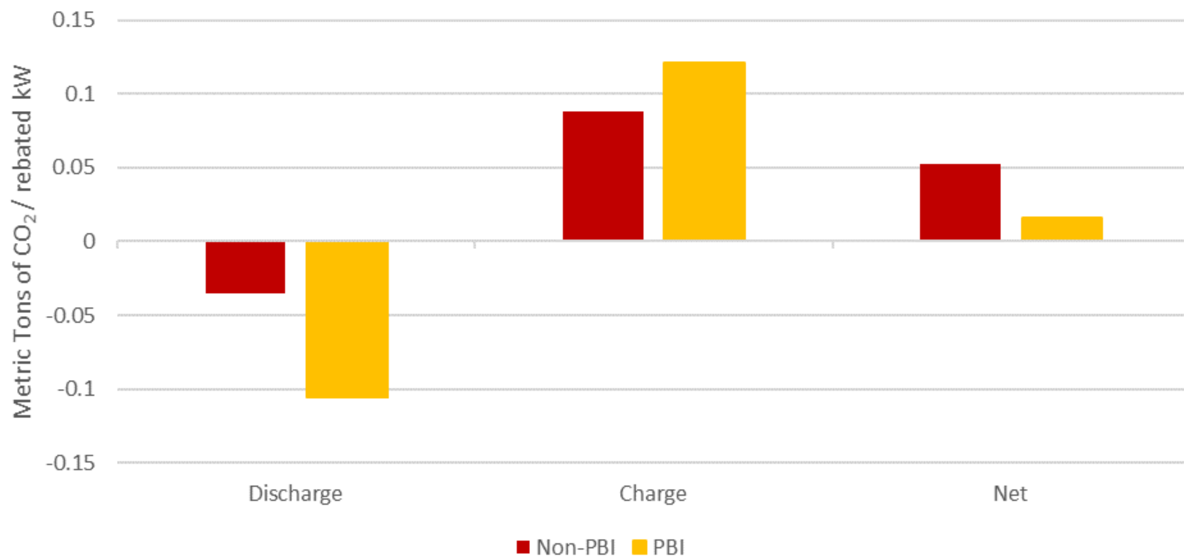
The evaluation team assessed the GHG[12] emissions impact of SGIP AES projects. We first developed a dataset of marginal power plant GHG emission rates for each 15-minute interval in 2016. Using this dataset, GHG emissions were calculated for each customer's load profile with SGIP AES, and without AES. 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 2016 are summarized in Figure 1-22.

GHG impacts for both PBI and non-PBI non-residential projects are positive, reflecting increased emissions. The magnitude and the sign of GHG impacts is dependent on the timing of AES charging and discharging. During 2016, non-residential SGIP AES projects increased GHG emissions by 726 metric tons of CO_2.

[12] 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 1-22: AVERAGE NON-RESIDENTIAL CO2 EMISSIONS PER SGIP REBATED CAPACITY



1.3.7 Observed Utility Marginal Cost Impacts

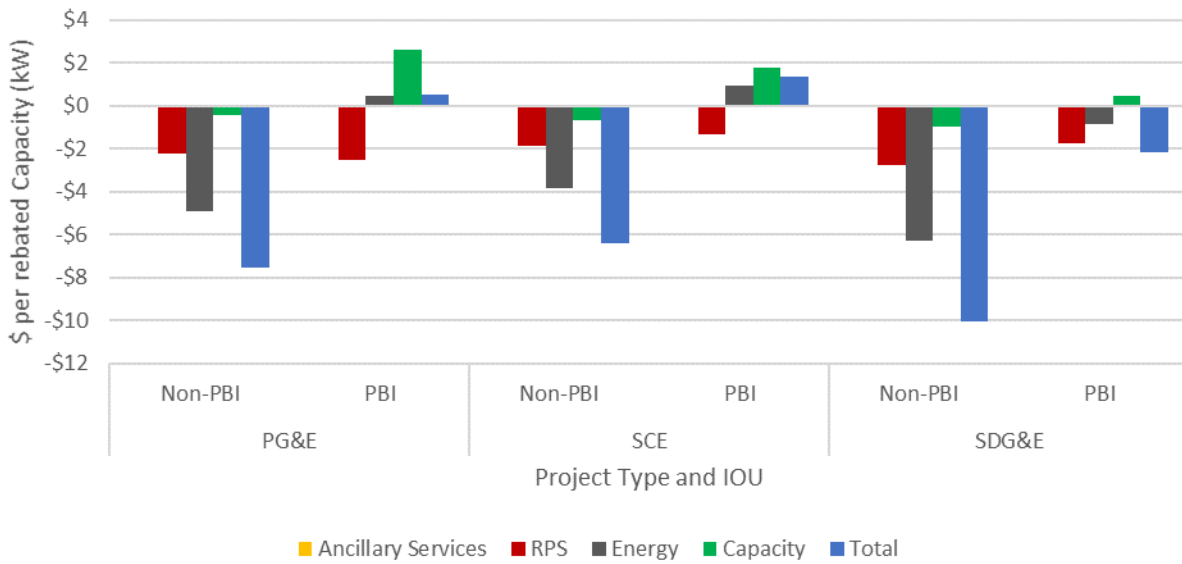
The evaluation team assessed the marginal cost impacts for each IOU using the E3 DER Avoided Cost Calculator. Storage system charging results in an increased load and therefore potential cost to the system and discharging results in a benefit, or avoided cost, to the system.

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, RPS,[13] and ancillary services ($/kWh).

The normalized utility marginal costs are shown in Figure 1-23 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 $0.50 per rebated capacity (kW) and the average marginal cost (-) for non-PBI projects is $8.10 per rebated capacity (kW). The total utility marginal avoided cost estimate for the SGIP AES population is $43,029 (avoided).

[13] Section 4 provides a detailed definition of RPS and all other marginal costs

FIGURE 1-23: MARGINAL COST $ PER REBATED CAPACITY (KW) BY IOU AND PROJECT TYPE



1.4 EVALUATION FINDINGS – SIMULATED OPTIMAL DISPATCH

Evaluation findings for a range of simulated optimal dispatch scenarios are summarized below. This analysis is helpful for two reasons: first, in comparing optimal dispatch under the customer perspective to empirically observed dispatch, we can evaluate the extent to which customers are responding to their utility rate signals. Secondly, comparing optimal customer perspective dispatch to optimal system perspective dispatch illustrates how well-aligned current retail rates are with actual system costs. Supporting detail is presented in Section 4.

1.4.1 Simulated Optimal Dispatch Results with DER Avoided Costs

Using 15-minute $/kWh avoided costs developed for 2016 with the DER Avoided Cost Model, adopted by the CPUC to evaluate the costs and benefits of energy efficiency, demand response, and distributed generation, the evaluation team simulated the benefits of AES for three storage dispatch perspectives: customer bill minimization, utility cost minimization, and CO_2 emission minimization. Using E3's RESTORE Storage Dispatch Optimization Model[14], the evaluation team optimized the dispatch of AES to minimize electricity bills under the customer perspective, system-level costs under the utility perspective, and CO_2 emissions under the carbon perspective. Under ideal simulated customer dispatch to minimize bills, customer bill savings for 2016 are $4.9 million. However, AES dispatched from the customer perspective increases grid costs and GHG emissions by $20,000 and 1,419 metric tons of CO_2

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

respectively. AES dispatched from the utility perspective to minimize grid costs provided net benefits of $5.1 million and reduces GHG emissions by 448 metric tons. However, under existing rates, customer bills would increase by $20.8 million. Finally, AES dispatch to minimize GHG emissions could realize a reduction of 18,804 metric tons of CO_2, with a system cost of $50,000 and a customer bill increase of $28.4 million.

TABLE 1-2: IMPACT OF SIMULATED IDEAL DISPATCH BASED ON CUSTOMER, UTILITY, AND CARBON OPTIMIZATION

	Customer Perspective	Utility Perspective	Carbon Perspective
Net Bill Savings ($ Millions)	$4.9	($20.8)	($28.4)
Net Avoided Cost Benefit ($ Millions)	($0.0)	$5.1	($0.1)
Avoided GHG Emissions (Metric Tons)	(1,419)	448	18,804

1.4.2 Potential Distribution Resource Planning Benefits

There is additional potential for AES to provide value in distribution resource planning, primarily by deferring expensive distribution system upgrades needed to meet anticipated load growth. In an area with high (greater than $100/kW-year) distribution system avoided costs, AES could have a net present value benefit as high as $3,500/kW installed. The benefits in an area with moderate upgrade costs might be in the range of $900 - $1,300/kW. In most areas, load-growth related upgrades are not necessary or quite small, with little or no incremental distribution system benefits over those already included in the DER Avoided Cost Model. Realizing distribution resource planning value, however, requires meeting several criteria that are not currently incorporated in the SGIP. AES deployment would have to be targeted to those locations with high distribution system avoided costs and achieved in sufficient quantity (kW and kWh) to achieve a deferral. AES would need incentives to be dispatched in response to local distribution system conditions. Finally, the response of AES would need to be considered reliable enough by utility distribution planners and operators such that they actually defer the planned upgrade. Integrating DER into utility distribution resource planning is currently being investigated in the CPUC Distribution Resource Plan (DRP) and Integrated Distributed Energy Resources (IDER) proceedings.[15]

1.4.3 Simulated Long Term Integrated Resource Planning Benefit

Using E3's RESOLVE model and a reference case 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 three cases are: A Low Value case in which

[15] CPUC proceeding numbers R. 14-08-013 and R. 14-10-003, respectively.

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 reserves; and a High Value case where AES can provide reserves. As with the simulated optimal dispatch analysis, AES dispatched for customer benefit and treated as a load modifier increases total grid costs, though only very slightly. In the Mid Value case, net present value (NPV) benefits from 2018 to 2030 are $6.6 million, predominately in variable operating cost savings.[16] In the High Value case with reserves (e.g., frequency regulation, energy reserves), the NPV value is just over double the Mid Value case at $18.9 million.

TABLE 1-3: CUMULATIVE VALUE OF SGIP AES ACROSS RESOLVE USE CASES, NPV 2016$ MILLION, 2018 – 2030

Use Case	Fixed Cost Savings	Variable Cost Savings	Total Cost Savings
Low Value	($0.00)	($0.01)	($0.01)
Mid Value	$0.76	$5.80	$6.56
High Value	$9.63	$9.22	$18.86

1.5 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. At a high level, of the types of benefits that SGIP AES projects can deliver, this analysis considers:

- Customer TOU bill management (arbitrage)
- Customer non-coincident demand charge reduction
- Coincident peak demand reduction
- Greenhouse gas emission reduction
- System peak demand reduction
- Distribution upgrade deferral
- Renewable generation integration

16 The NPV calculation only accounts for grid benefits and does not include any AES system costs, SGIP administrative costs, or incentive payments.

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 projects 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 2016 SGIP AES impact evaluation. Where possible, the evaluation team also provides considerations and recommendations.

1.5.1 Round Trip Efficiencies and Greenhouse Gas Emissions

The mean observed RTE was 44% for non-PBI projects and 74% for PBI projects over the 2016 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 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 "duty 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 recommend that the PAs identify ways to increase energy storage utilization in order to reduce the influence of parasitic losses. This should be done carefully to not simply promote increased cycling of energy storage projects without a clear objective.

A project's RTE by itself is not necessarily a bellwether for GHG emissions reductions. The simulated dispatch analysis demonstrated that all projects, even those with low RTEs, *can* achieve GHG reductions when optimally dispatched to do so. This is because there are several hours during the year when a zero-marginal-emissions resource is on the margin. Regardless of how low the RTE of a storage project is, if it charges only during these hours, the result would be a net reduction in total emissions. On the other hand, the same analysis showed that when dispatch is optimized to maximize customer bill savings, almost all projects increase GHG emissions regardless of their RTE. This is due to imperfect alignment between the retail rate signals and actual marginal emission rates. RTEs alone are not sufficient to guarantee GHG emissions reductions, as GHG emissions are a function of both the round-trip efficiency of a storage project and the emissions rate arbitrage that the project can realize.

The evaluation team recommends that additional performance metrics, such as the difference between the system-level average emissions rate at discharge and at charge, be developed for program eligibility requirements as they relate to GHG emissions. While it is true that there is volatility on a daily or hourly basis (partly due to curtailment) of marginal emissions rates, marginal emissions rates reliably follow the marginal price of energy generation, which is more predictable. As indicated by the optimal dispatch results, if storage were dispatched solely to minimize system costs, this dispatch would also result in a reduction in CO_2 emissions. Thus, though not perfect, prioritizing reduction of system costs would be a step in the right direction towards emission reductions. The recommendations below for reducing system costs through storage dispatch are in turn recommendations for reducing CO_2 emissions.

1.5.2 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 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. More dynamic rates that better align customer and grid benefits could provide substantial ratepayer and environmental benefits that are currently unrealized. This is supported by comparing the aggregate results by rate type, where we see that customers subject to a real-time price rate benefit the system the most, followed by those subject to Critical Peak Pricing (CPP). Customers without either of these levels of granularity, in aggregate, impose costs on the system when dispatching storage to minimize their bills. Furthermore, we find that “sharper” signals like demand charges or DR signals create a more visible impact on storage dispatch compared to comparatively broad TOU peak periods of 6-8 hours.

1.5.3 Considerations for Integrated Resource Planning

The RESOLVE analysis found that strictly as a load modifier (proxy for business-as-usual), SGIP AES produces a slight increase in overall system costs. However, at the High Value case, total cost savings approaching $20 Million are possible. This demonstrates that significant value is left on the table if SGIP AES is not available to be dispatched by grid operators (or called upon through a market mechanism) for system-level benefits. 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 planning reserve margins and flexible Resource Adequacy requirements 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.

1.5.4 Data Availability and Data Delivery Timing

The evaluation team received data from several project developers representing hundreds of SGIP energy storage projects. These data, combined with data provided from other sources, allowed for an unprecedented depth of analysis in this evaluation report. However, data quality issues, limited data availability (especially for residential projects), and the timeliness of data delivery provided significant hurdles for the evaluation team to analyze impacts and report results. We provide the following recommendations to improve the availability, quality, and timeliness of residential and non-residential data delivery:

- Program Administrators should evaluate the current processes for ensuring that SGIP AES projects are collecting data of sufficient quality for impact evaluation purposes. Additional metering for M&E purposes may be required for residential projects.
- Project developers should provide clear and concise data documentation that details the definitions, development, and applicability of each piece of data sent for the evaluation. Data requests for information often lagged in time and follow-up meetings/emails were required with project developers to better understand the data they had provided. This caused a serious time delay in our analysis and reporting.
- Every project developer should, at a minimum, maintain a tracking system that links each storage system to a specific SGIP Reservation Number. The evaluation team had to perform project address look-ups and other investigative techniques to link a specific data file to an SGIP project.
- IOUs should send information on outage events to clarify the nuances between when a meter read is zero versus missing.

- Data acquisition systems should be continually monitored to assess the quality of collected data. Long gaps in data (especially for residential projects) and data spikes increased the time needed to quality control the data that were provided.

1.5.5 Other Residential Project Considerations

Despite data quality issues, the evaluation team made a qualitative assessment of residential storage behavior. A large portion of residential projects 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 evaluation found that non-residential projects responded most strongly to sharp signals like demand charges and demand response participation, followed by softer signals like TOU peak periods. Residential customers do not currently experience demand charges, and currently few participate in TOU rates. Few residential projects in our sample are believed to participate in demand response programs that energy storage could support. Many residential customers are on tiered, non-TOU volumetric retail energy rates, and consequently present few opportunities for cost-effective storage dispatch. We recommend that the CPUC and Program Administrators examine how they expect residential AES projects to dispatch, and how that dispatch is aligned with SGIP goals. Providing backup power to customers is not a stated goal of the SGIP program. We recommend that residential projects be required to participate in ancillary services or demand response programs, or demonstrate other types of benefits that are aligned with overall SGIP goals.

1.5.6 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. We found that during 2016 there was no discernable difference in performance between non-residential AES systems paired with PV and standalone AES projects. The data indicated that non-residential 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.

Going forward the Program Administrators have modified SGIP eligibility rules to encourage AES charging from PV. This new requirement will only apply to projects rebated during PY 2017 and therefore will provide an opportunity to test the impacts of this storage use case.

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 where standalone AES projects (in addition to those paired with SGIP eligible technologies or PV) were made eligible for incentives.

Authorized incentive collections for PY 2016 totaled $77,190,000. Allocations for each PA are summarized in Table 2-1. 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.

TABLE 2-1: PROGRAM YEAR 2016 STATEWIDE PROGRAM BUDGET AND ADMINISTRATOR ALLOCATIONS

Program Administrator	Authorized Incentive Collections
PG&E	$33,480,000
SCE	$26,040,000
CSE	$10,230,000
SCG	$7,440,000

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.

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 & Electric (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 & Electric (SDG&E).

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

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[4] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. Passage of Senate Bill (SB) 412[5] (Kehoe, October 11, 2009) refocused the SGIP toward greenhouse gas (GHG) emission reductions.

CPUC Decision (D.) 16-06-055 (June 23, 2016) revised the SGIP pursuant to SB 871 and AB 1478.[6] 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 non-residential 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.

2.1.1 Scope

The scope of this impact evaluation includes but is not limited to the metrics discussion in Section 2.1. This evaluation is an assessment of energy storage projects that received an SGIP incentive on or before December 31, 2016. Figure 2-1 shows growth in SGIP rebated capacity[7] over time. By the end of 2016, the SGIP had provided incentives to 716 advanced energy storage projects representing almost 49 MW of rebated capacity. SGIP incentives are available for electrochemical, mechanical, and thermal energy

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

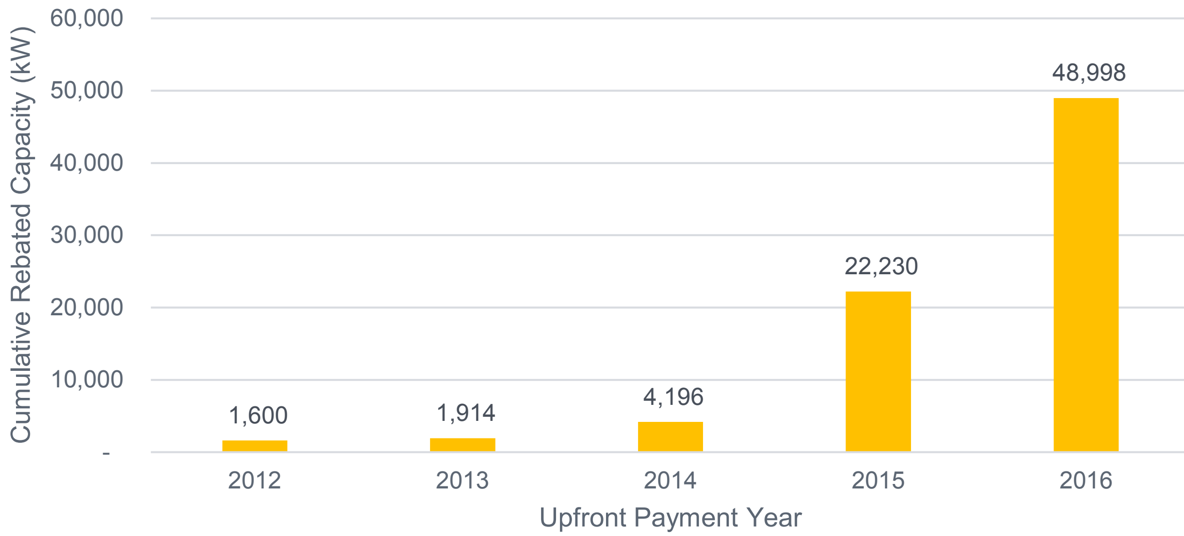
5 http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

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

7 As of PY 2016, 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 are often up to 2x greater than the SGIP rebated capacity value.

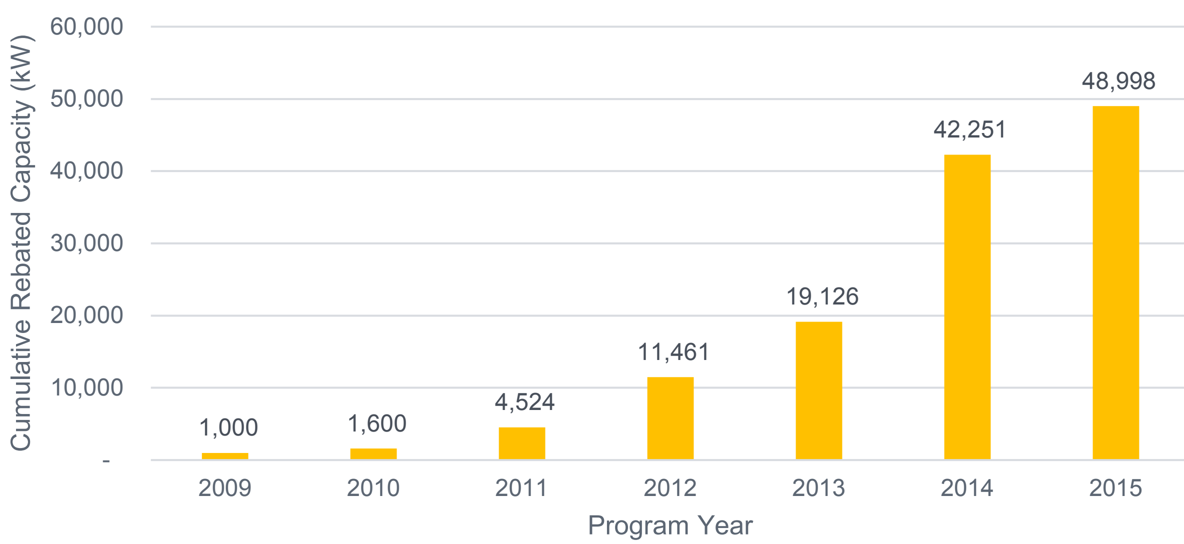
storage. As of December 31, 2016, all SGIP rebated storage projects were electrochemical (battery) energy storage technologies.

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



Energy storage projects saw significant growth during calendar years 2015 and 2016, adding approximately 20 MW of rebated capacity per year on average. Figure 2-2 shows growth in storage rebated capacity by program year (the year a project applied to the SGIP).

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



SGIP storage projects grew significantly during PY 2014. Because this report is limited to projects that were paid an upfront incentive on or before December 31, 2016, many PY 2015 and all PY 2016 projects were likely going through the application review process by the evaluation cutoff date and therefore are not included in this evaluation. 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[8] by PA. PG&E has the most number of projects and the largest portion of the rebated capacity, followed by SCE and CSE. As of December 31, 2016, only two 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 & Electric	302	21,534	$ 45,474,935
Southern California Edison	248	18,101	$ 33,733,976
Southern California Gas Company	2	625	$ 1,254,000
Center for Sustainable Energy	164	8,738	$ 15,038,894
Total	***716***	***48,998***	***$ 95,501,805***

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 have energy storage projects installed at non-IOU electric customer locations. Most (681/716) SGIP energy storage projects are installed at electric-IOU customer locations.

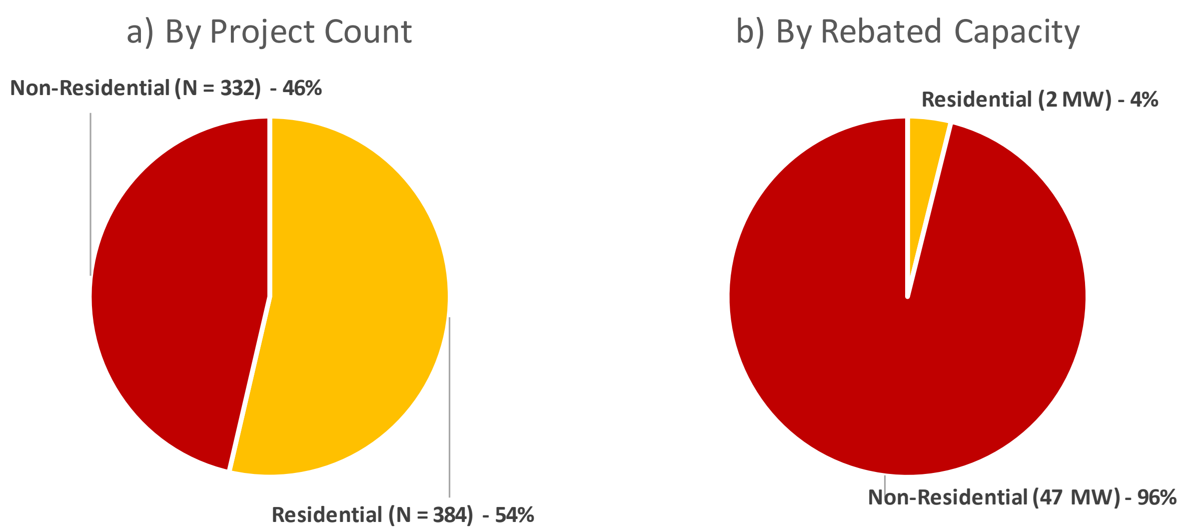
TABLE 2-3: ENERGY STORAGE PROJECT COUNTS AND REBATED CAPACITY BY PROGRAM ADMINISTRATOR AND ELECTRIC UTILITY TYPE

Program Administrator	Number of Projects		Rebated Capacity (kW)	
	IOU	Municipal	IOU	Municipal
Pacific Gas & Electric	268	34	21,381	153
Southern California Edison	248	0	18,101	0
Southern California Gas Company	1	1	600	25
Center for Sustainable Energy	164	0	6,738	0
Total	***681***	***35***	***48,820***	***178***

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

SGIP storage projects are installed at both residential and non-residential 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 (96%) is installed at non-residential customer sites. Non-residential 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[9] 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 and PBI program requirements. There are 83 PBI projects in the SGIP population representing roughly 40 MW of the 49 MW total SGIP storage rebated capacity. All PBI projects are installed at non-residential 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.

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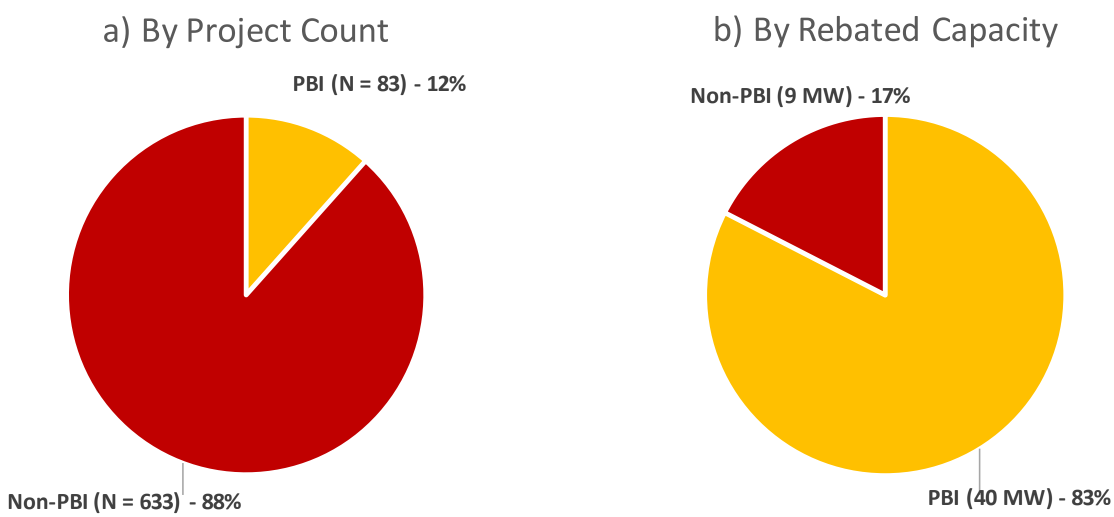
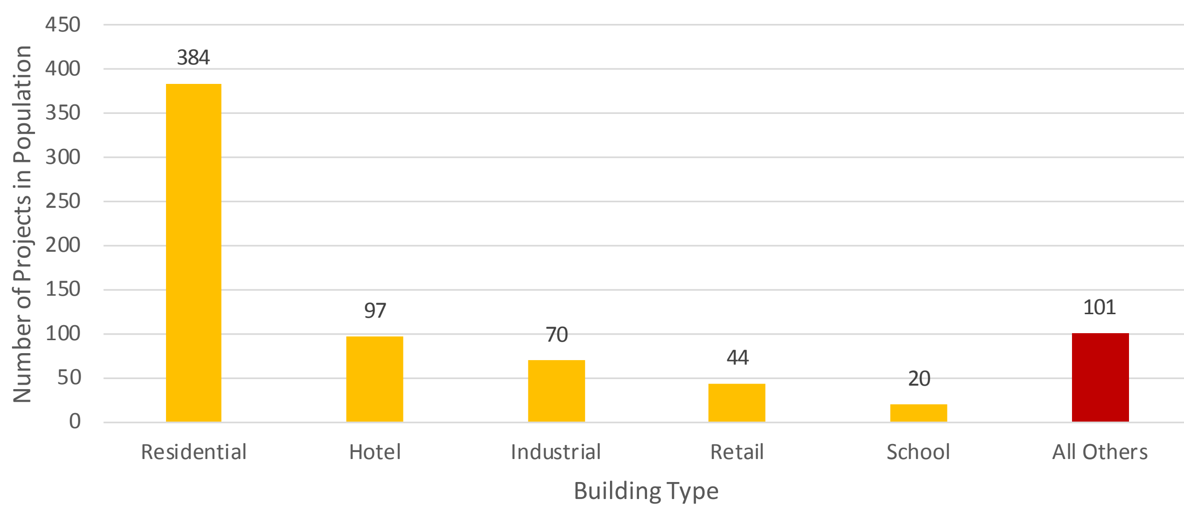
9 *2016 Self-Generation Incentive Program Handbook*, 2016, available at https://www.selfgenca.com/home/resources/

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



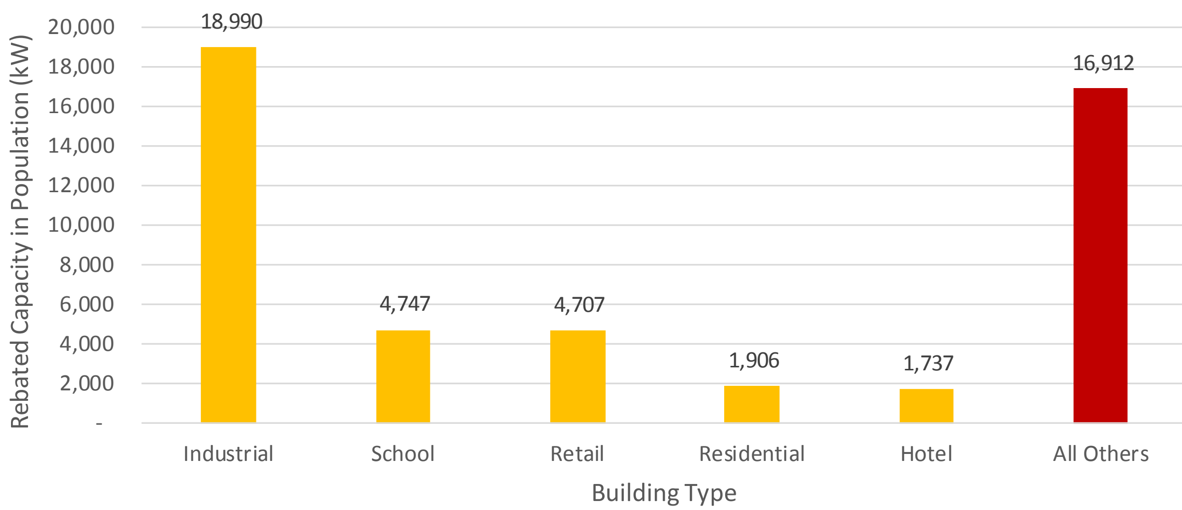
Energy storage projects are installed at a variety of building types. Figure 2-5 summarizes the distribution of building types in the SGIP energy storage population by project count.

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 (384/716), followed by hotels (97), industrial facilities (70), retail locations (44), and schools (20). All other building types combined make up the remaining 101 energy storage project locations. However, residential energy storage projects are relatively small (approximately 5 kW rebated capacity each on average) compared to non-residential energy storage projects (approximately 140 kW rebated capacity each on average). Figure 2-6 shows the distribution of SGIP energy 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



Evaluation Period

This impact evaluation covers performance during the twelve-month period ending December 31, 2016. For projects that became operational during 2016, we estimate partial-year impacts based on the start of normal operations. Additional details on the evaluation methodology and approach are included in 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[10], 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
  - 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
- 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 3. Details on the estimation methodology are provided in Appendix B.

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

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

We employ two distinct approaches to quantify potential benefits of energy storage. The first is a short-term marginal cost approach using the E3 Distributed Energy Resource (DER) Avoided Cost Model. This is consistent with the approach used by the CPUC to evaluate costs and benefits of DERs, including energy efficiency, demand response, and distributed generation. The long-term resource plan and operation of the electric grid evolves over time, but only the marginal generation resource, be it fossil or renewable generation, increases or decreases its output when AES is charging or discharging. Using 15-minute $/kWh avoided costs, we quantify the benefits of AES for three storage dispatch perspectives: customer bill minimization, utility cost minimization, and carbon emission minimization. Using E3's RESTORE Storage Dispatch Optimization Model, we optimize the dispatch of AES to minimize costs or GHG emissions from each perspective.

The second approach we use to quantify potential benefits is a long-term integrated resource planning approach with E3's Renewable Energy Solutions (RESOLVE) model.[11] This approach is being used in the CPUC Integrated Resource Planning Proceeding. We model three cases: 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 reserves (e.g., frequency regulation, spinning reserves, energy reserves), and a High Value case where AES can provide reserves.[12]

2.3 REPORT ORGANIZATION

This report is organized into four 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 in addition to presenting population statistics at the end of the evaluation period
- Section 3 characterizes the metered sample and presents the observed program impacts

[11] https://www.ethree.com/tools/resolve-renewable-energy-solutions-model/

[12] 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. These reserves can include frequency response, load following, and spinning/non-spinning reserves.

- Section 4 summarizes potential storage benefits in the short-term and 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 impact estimation methodology
- Appendix C provides additional figures and tables that were not included in the main body of the report

3 OBSERVED ADVANCED ENERGY STORAGE IMPACTS

3.1 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 2016. The evaluation team analyzed several different impact metrics:

- AES performance metrics – including roundtrip efficiencies and capacity factors
- AES dispatch behavior – including an analysis of charge/discharge behavior in relation to customer noncoincident peak demand, time-of-use (TOU) schedules, and monthly bill savings
- Electric utility and CAISO system impacts – including an analysis of charge/discharge behavior in relation to CAISO system load and utility coincident peak demand
- Carbon dioxide (CO_2) impacts[1] – including an analysis of charge/discharge behavior in relation to marginal greenhouse gas (GHG) emission rates
- Utility marginal costs – including an analysis of charge/discharge behavior in relation to utility energy, system capacity, transmission, renewable portfolio standard (RPS), and ancillary services costs
- Photovoltaic (PV) pairing – including an analysis of how storage is utilized at facilities that also have generation from PV
- Extension of the sample level metrics to the population of SGIP projects to develop total population impacts

The remainder of this section discusses these impact metrics in more detail, provides detailed information about the population of SGIP projects operating during 2016, and describes the sample of projects the evaluation team ultimately analyzed. Data quality and data collection issues limited our ability to fully develop the impact metrics discussed above for certain customer segments and projects in the 2016 population. We will discuss those limitations and provide an analysis of how the sample level impacts extrapolate to the 2016 population.

[1] 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.

3.2 POPULATION AND SAMPLE CHARACTERIZATION

The 2016 AES population is defined as any project receiving an upfront incentive on or before December 31, 2016. The population represents residential and non-residential projects covering several different customer segments and storage capacity sizes. Non-residential projects are further split into two categories: 1) performance-based incentive[2] (PBI) projects and 2) non-PBI projects. PBI projects are those with a rebated capacity greater than or equal to 30 kW that applied to the SGIP during or after the 2011 program year (PY). All but two projects in the population were rebated during or after PY 2011 and therefore are subject to Senate Bill (SB) 412 provisions and PBI program requirements.

Table 3-1 presents the total number of projects in the 2016 population (shown as 'N') along with the total capacity for each customer segment and storage category, by program administrator (PA). Table 3-1 also presents the total number of projects represented in the analysis sample (shown as 'n'). The 2016 population comprised 331 non-residential and 385 residential projects (716 total). Of the 331 non-residential projects, 248 are non-PBI projects (< 30 kW) and 83 are PBI projects. Non-residential projects (47 MW) account for a large majority of a total of roughly 49 MW. The most significant contribution of capacity comes from non-residential PBI projects (40.5 MW).

The analysis sample, comprising all projects for which at least some metered data were available, accounted for roughly 82% of projects (85% of total rebated capacity). This represents 259 non-residential projects and 327 residential projects. We developed performance metrics, analyzed coincident and non-coincident peak dispatch, and assessed the impacts on CO_2 for all the non-residential projects in the sample and analyzed customer bill impacts for 222 non-residential projects. For residential projects, data accuracy issues precluded quantification of storage performance. However, we developed some metrics that provide a qualitative assessment of performance.

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

TABLE 3-1: 2016 SGIP POPULATION AND ANALYSIS SAMPLE BY PA, CUSTOMER SECTOR, AND INCENTIVE PAYMENT RULE

PA	Project Type	PBI	Project Count			Rebated Capacity (kW)		
			N	n	% in Sample	N	n	% in Sample
PG&E	Non-residential	N	97	80	82%	3,001	1,617	54%
	Non-residential	Y	37	33	89%	17,710	16,068	91%
	Residential	N	168	144	86%	823	590	72%
	All		**302**	**257**	**86%**	**21,534**	**18,275**	**85%**
SCE	Non-residential	N	82	44	54%	1,634	831	51%
	Non-residential	Y	34	34	100%	15,805	15,805	100%
	Residential	N	132	117	89%	662	585	88%
	All		**248**	**195**	**79%**	**18,101**	**17,221**	**95%**
CSE	Non-residential	N	67	56	84%	1,379	1,209	88%
	Non-residential	Y	12	11	92%	6,934	4,434	64%
	Residential	N	85	66	78%	425	330	78%
	All		**164**	**135**	**82%**	**8,738**	**5,958**	**68%**
SCG	Non-residential	N	2	1	50%	625	25	4%
	All		**2**	**1**	**50%**	**625**	**25**	**4%**
Total	**Non-residential**	**N**	**248**	**181**	**73%**	**6,639**	**3,681**	**55%**
	Non-residential	**Y**	**83**	**78**	**94%**	**40,449**	**36,307**	**90%**
	Residential	**N**	**385**	**327**	**85%**	**1,910**	**1,505**	**79%**
	All		**716**	**586**	**82%**	**48,998**	**41,493**	**85%**

3.2.1 Non-residential Sample Characterization

The evaluated sample encompassed 259 non-residential AES projects online during 2016. 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. The range of rebated capacities for PBI projects is significant with the smallest AES system at 30 kW and the largest at 2,600 kW. Figure 3-1 presents the distribution of evaluated projects by capacity. Non-PBI[3] projects represented 181 projects (70% by project count) and PBI projects represented 78 (the remaining 30%).

[3] There are two projects in the 2016 population with rebated capacities > 30 kW, but are not classified as PBI because they were rebated prior to PY 2011. These projects are not in the metered sample.

FIGURE 3-1: 2016 SGIP NON-RESIDENTIAL SAMPLE REBATED CAPACITY BY PROJECT COUNT

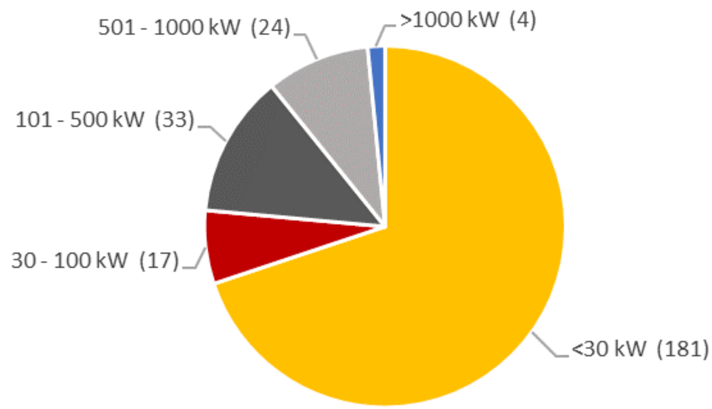
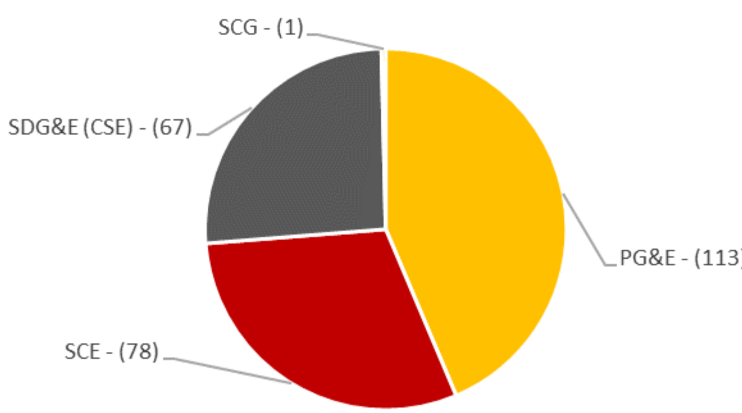


Figure 3-2 presents the distribution of projects in the sample by PA and project count. Projects administered by PG&E represent the greatest share (43.6%). Projects administered by CSE and SCE represent roughly an equal share at 30.1% and 25.9%, respectively. There was also one SCG project included in the metered sample.

FIGURE 3-2: 2016 SGIP NON-RESIDENTIAL SAMPLE PROJECT COUNT BY PA



Another important characteristic of the sample is the customer segment. While all evaluated projects represent the non-residential population, the building types represented in that population are quite varied. Customer segments potentially have different operating schedules throughout the year which can have a significant impact on the storage discharge behavior of the AES system. Some facilities may experience peak demand periods that are noncoincident to system peak hours, whereas the opposite may be true for others. Figure 3-3 presents the distribution of building types representing the evaluated 2016

AES projects (by project count) and Figure 3-4 presents the distribution of building types by rebated capacity. Hotels represent the greater share of total project count at 36%, followed by industrial facilities (18%) and retail establishments (13%). When examining the distribution by rebated capacity, industrial facilities represent the most significant share at 42%. There were 90 AES projects evaluated at hotels, but these projects generally represented small systems (<30 kW). The "All Others" category represents the sum of all other building types with less than 3% representation in the evaluated sample. This category includes offices, warehouses, health care facilities, and other miscellaneous building types.

FIGURE 3-3: 2016 SGIP NON-RESIDENTIAL SAMPLE BY BUILDING TYPE AND PROJECT COUNT

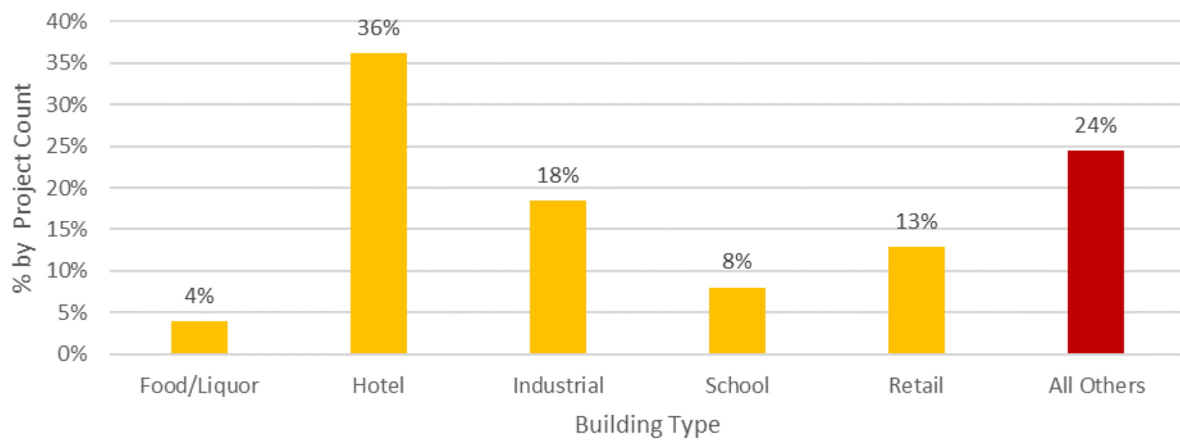
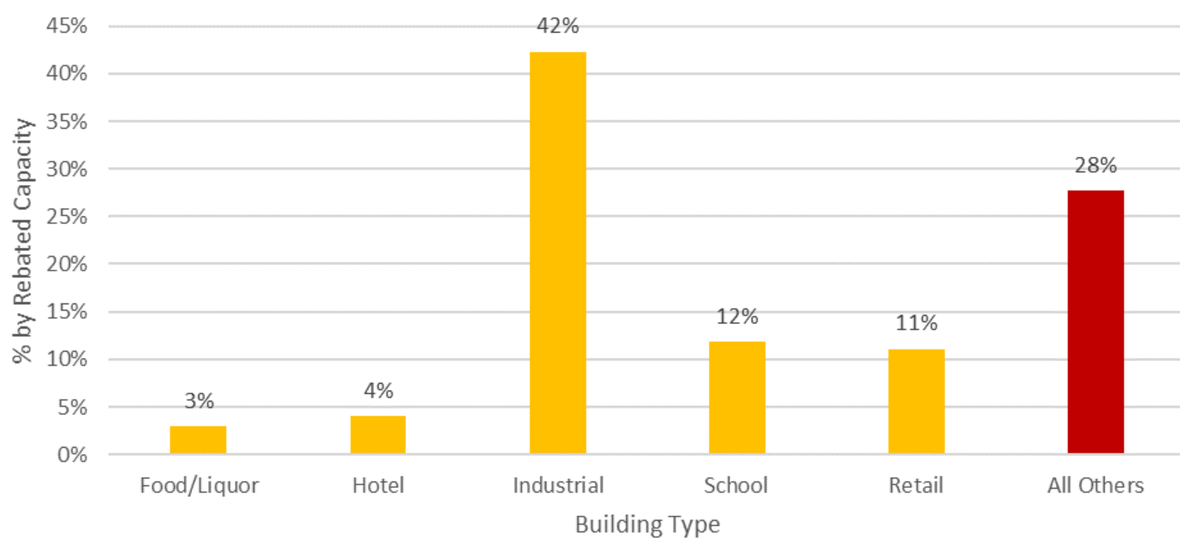


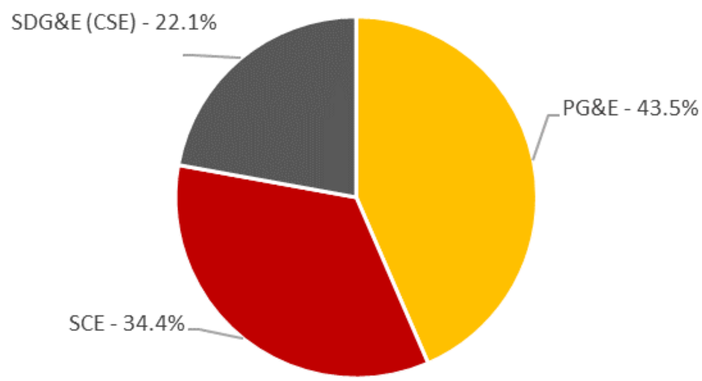
FIGURE 3-4: 2016 SGIP NON-RESIDENTIAL SAMPLE BY BUILDING TYPE AND REBATED CAPACITY



3.2.2 Residential Sample Characterization

Of the 385 residential projects in the population, we received data for 327 projects. The storage systems range from 2 to 11 kW rebated capacity with 86% representing 5 kW systems within homes. Figure 3-1 presents the distribution of projects in the sample by PA and project count. Projects administered by PG&E represent the greatest share (43.5%). Projects administered by CSE and SCE represent 22.1% and 34.4%, respectively.

FIGURE 3-5: 2016 SGIP RESIDENTIAL SAMPLE BY PA



3.3 DATA CLEANING

As discussed in Section 2 and Appendix B, the storage analysis leveraged a variety of data sources including project developers, Energy Solutions (for projects that received a PBI incentive), and the electric utilities. We conducted an extensive data cleaning and quality control exercise to ascertain whether the data were verifiable:

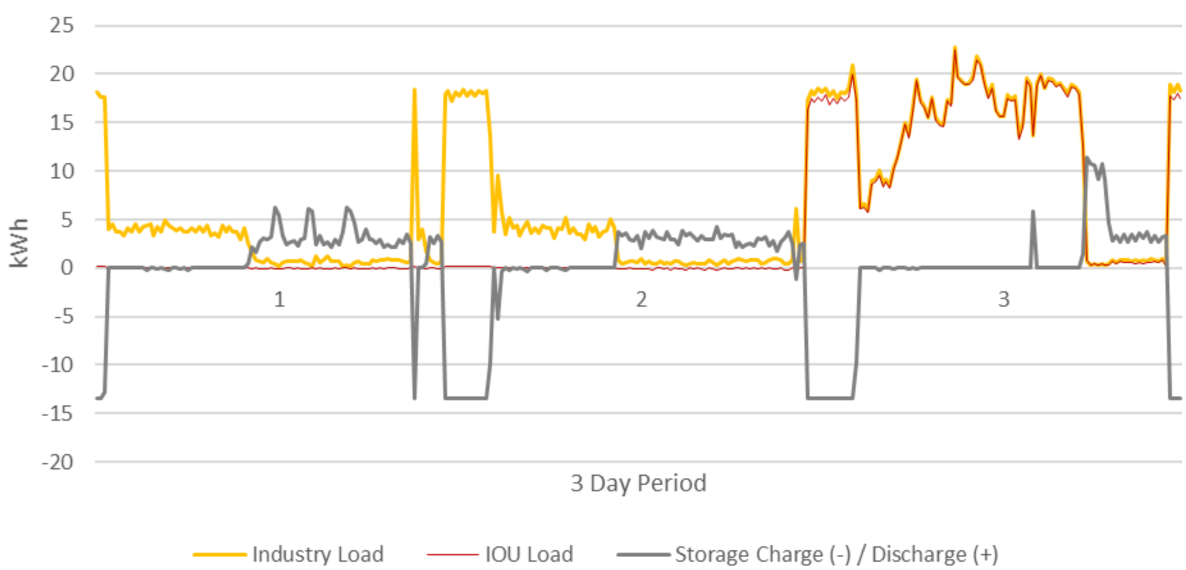
- Interval load data from IOUs were verified against Itron monthly billing data
- Interval and load data were aligned to Pacific Standard Time (PST). Data for each time interval were set to the beginning of the time interval.
- Visual inspections of storage dispatch and load data were conducted for all projects where we received data. This allowed the evaluation team to verify if, for example, metered load data increased at the same time interval as the battery was charging (time syncing).
- When battery data were provided by the project developer and the PBI database, we conducted quality control (QC) on both data streams and, often, stitched the data throughout the year to develop a more robust data set for each project.

- When load data were provided by the project developer and the IOU, we conducted QC on both data streams and, often, stitched the data throughout the year to develop a more robust data set for each project.
- We reviewed hourly, daily, and monthly performance metrics to determine whether the data were accurate.

Figure 3-6 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 3-6: EXAMPLE OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT

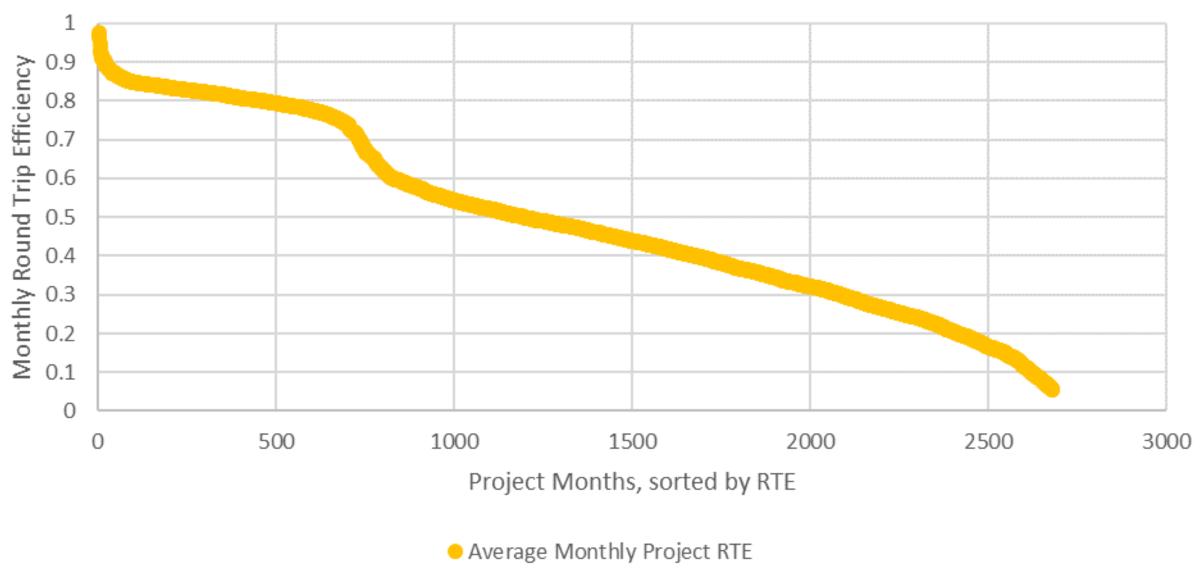


Storage systems inherently increase energy consumption. Because of losses in the battery, less energy can be discharged than is stored in the battery. This fact provided an additional QC benefit. After we removed data that were completely missing or clearly corrupt, we examined the roundtrip efficiency (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 3.4.1 discusses this performance metric in detail).

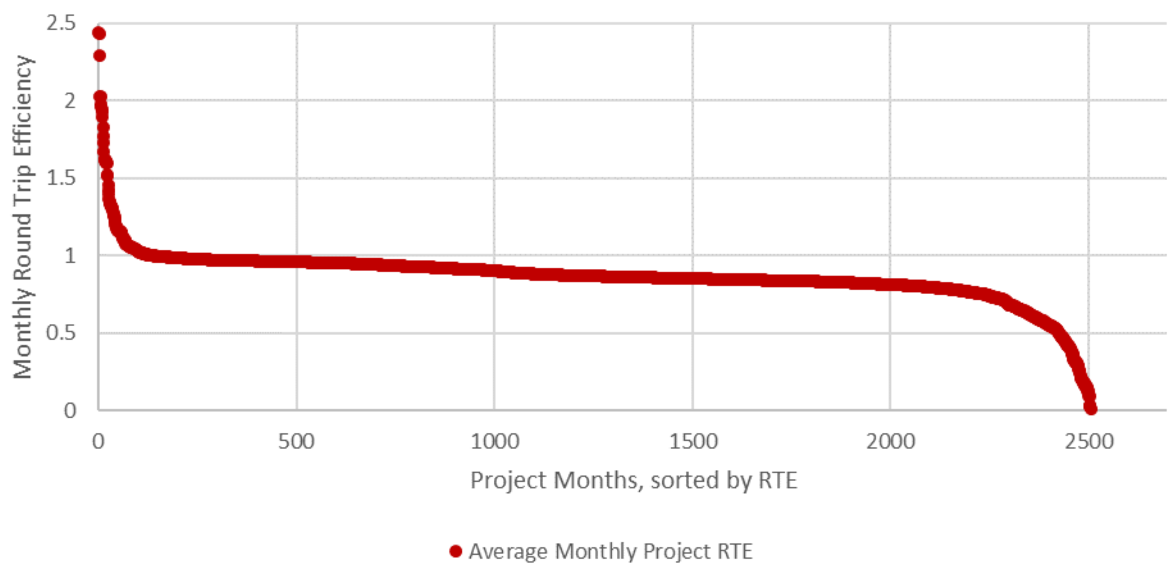
Figure 3-7 presents the monthly RTEs for each of the projects in the analysis sample (non-residential only). Overall, the storage data from non-residential projects was verifiable in that the ratio of discharge to charge was less than one. There were cases when the dispatch data were poor, however. For example, a project file may have a full month of discharge data, but the charging data were missing or incomplete. This would lead to an RTE greater than one. The data QC process allowed us to examine the data for that month and invalidate poor data, where applicable.

FIGURE 3-7: MONTHLY ROUNDTRIP EFFICIENCIES FOR NON-RESIDENTIAL PROJECTS (SORTED BY HIGHEST RTE)



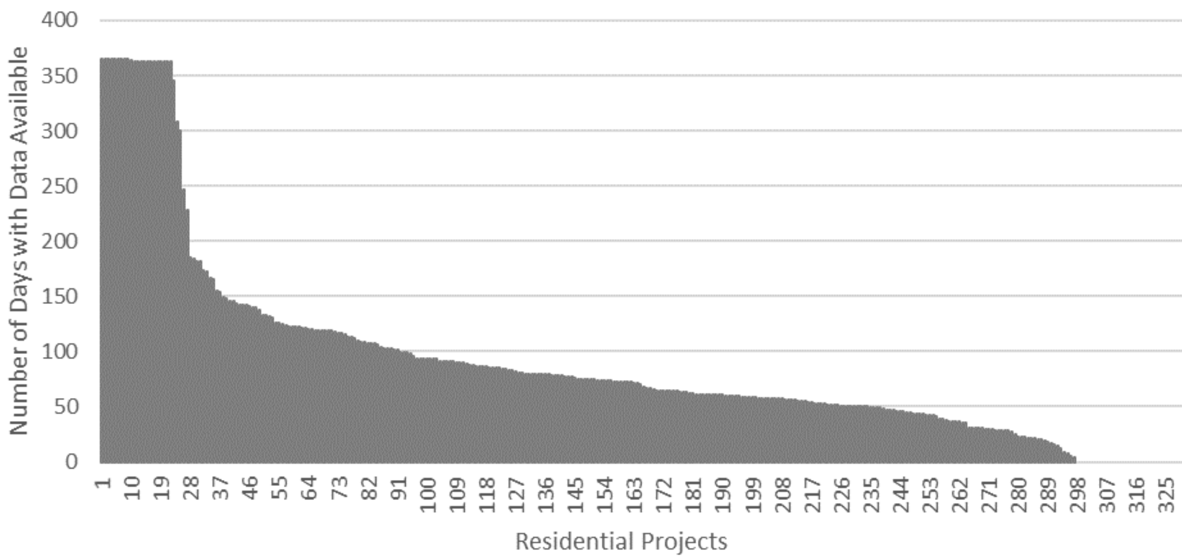
We performed the same exercise on residential projects. We encountered far more data quality issues with residential projects than non-residential projects. The primary issues were long stretches of low discharge and charge. A significant number of projects (roughly 84% of all 15-minute power reads) had a 12 to 16-watt discharge that would occur over the course of several days followed by a quick charge event. The discharge events were so small that the battery appeared idle. These events tended to occur over a significant portion of the metering periods and we were unable to confirm whether it was a parasitic load or measurement error. Similarly, data availability for residential storage systems relied on cellular coverage which can easily be interrupted through interference. These issues resulted in large and frequent gaps in available data. After removing the obvious outliers, we examined the RTEs of the remaining projects in the same manner as non-residential projects. Figure 3-8 presents those data. As evidenced in the data, a significant percentage of projects exhibited monthly RTEs at or near one (including above one).

FIGURE 3-8: MONTHLY ROUNDTRIP EFFICIENCIES FOR RESIDENTIAL PROJECTS (SORTED BY HIGHEST RTE)



Another concern that hindered our ability to conduct the analysis was the scarcity of data we received for projects. While we received data for a significant percentage of residential storage projects, there were large gaps in the data which made it difficult to analyze impacts over the course of the year. Figure 3-9 conveys the total number of days of available data for residential projects after we performed our initial data QC exercises. Most projects had less than 50% data availability for calendar year 2016.

FIGURE 3-9: DAYS OF STORAGE DATA AVAILABLE FROM ALL RESIDENTIAL PROJECTS



3.4 PERFORMANCE METRICS

3.4.1 Capacity Factor and Roundtrip Efficiency

Non-Residential Projects

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. 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."[4] For purposes of SGIP evaluation, the AES capacity factor is calculated as:

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

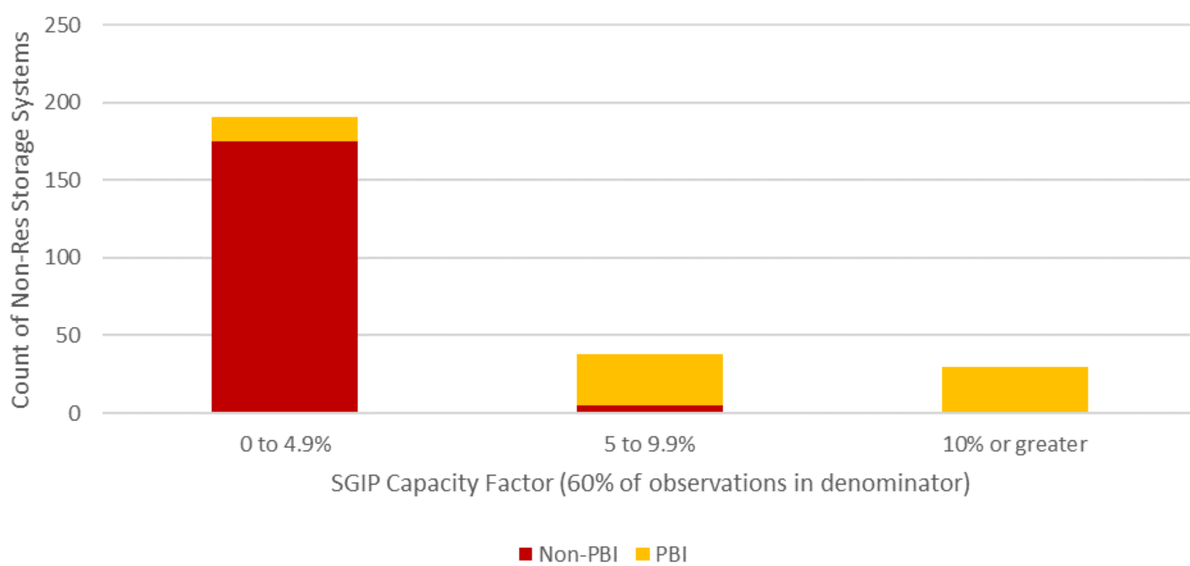
[4] See 2015 SGIP Handbook, p. 37.

The SGIP Handbook requires that PBI projects achieve an AES capacity factor of at least 10% per the above formula, 520 hours over the course of each year, to receive full payment.[5] Non-PBI projects are not required to meet a 10% capacity factor.

The capacity factors for the non-residential AES projects are presented below in Figure 3-10. A total of 191 projects have capacity factors of less than 5% (of 259 total sampled projects) with non-PBI projects representing much of that total (175). We observed 39 projects with a capacity factor between 5 and 10% with 5 of those representing non-PBI projects and 34 representing PBI projects. Thirty projects exhibited capacity factors of a least 10%. All but one of these projects was PBI. The mean capacity factor was 2.3% for non-PBI projects and 8.1% for PBI projects during the evaluation period.

Capacity factors alone are not indicators of performance – they only indicate the extent to which a storage system was discharging during a given period. The capacity factors shown in Figure 3-10 were calculated across the entire evaluation period. Subsequent sections will examine performance during specific months, seasons, and TOU periods.

FIGURE 3-10: HISTOGRAM OF NON-RESIDENTIAL AES DISCHARGE CAPACITY FACTOR (2016)

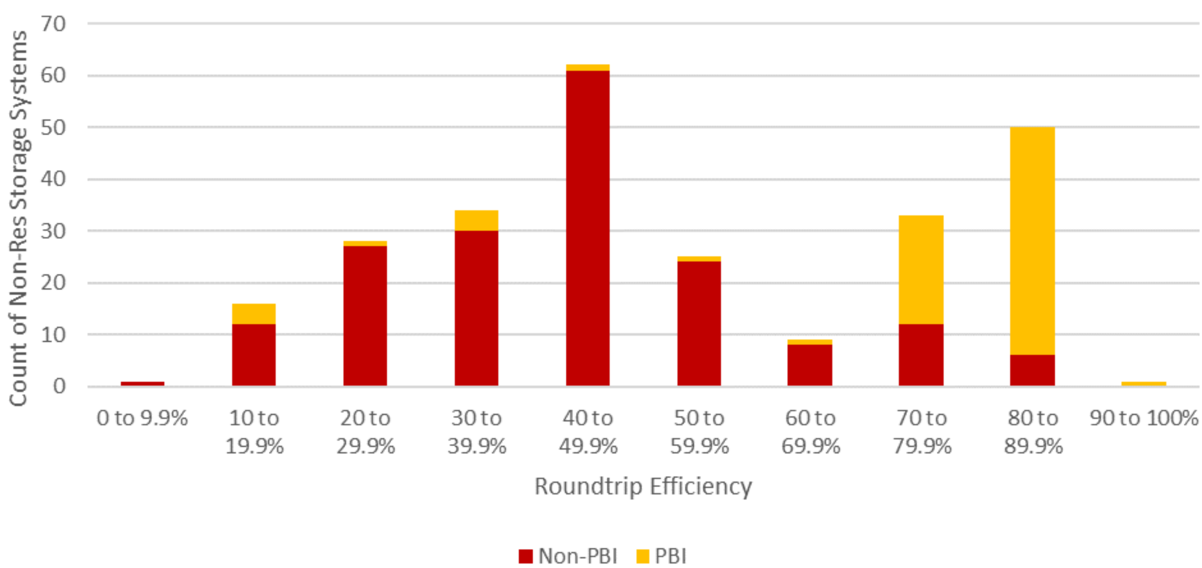


5 "520 discharge hours" refers to the amount energy released when discharging a battery at full capacity for 520 hours. AES projects typically discharge during peak weekday periods and are unable to discharge during their charging period. For this reason, 5,200 hours per year will be used for the purposes 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.

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 QC process to verify that there were no underlying data quality issues. Figure 3-11 presents the distribution of RTEs for PBI and non-PBI projects and Figure 3-12 presents the RTEs for each of the 259 projects by descending efficiency.

The mean observed RTE was 44% for non-PBI projects and 74% for PBI projects over the entire evaluation period.

FIGURE 3-11: HISTOGRAM OF NON-RESIDENTIAL ROUNDTRIP EFFICIENCY (2016)



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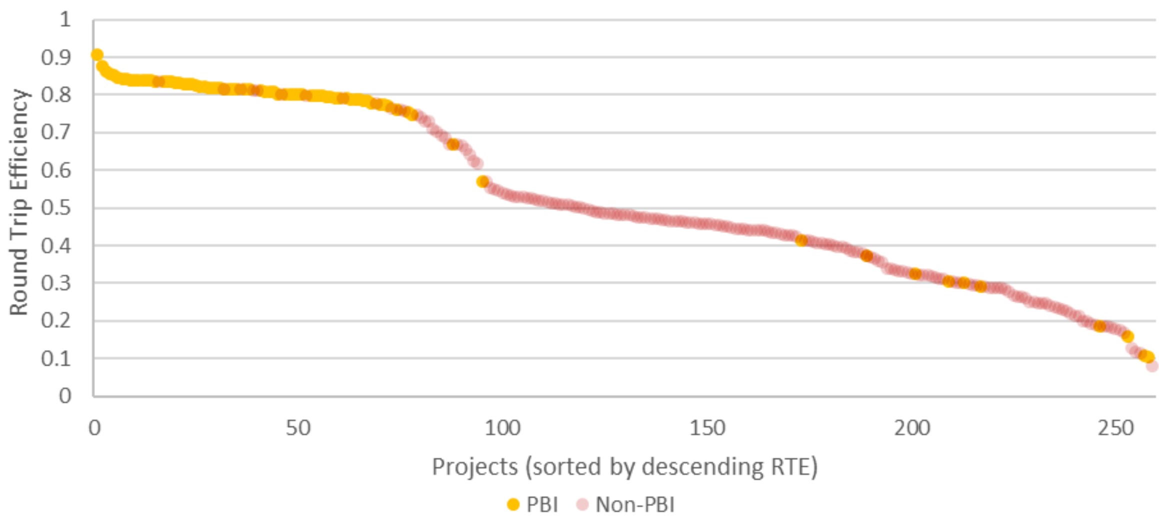
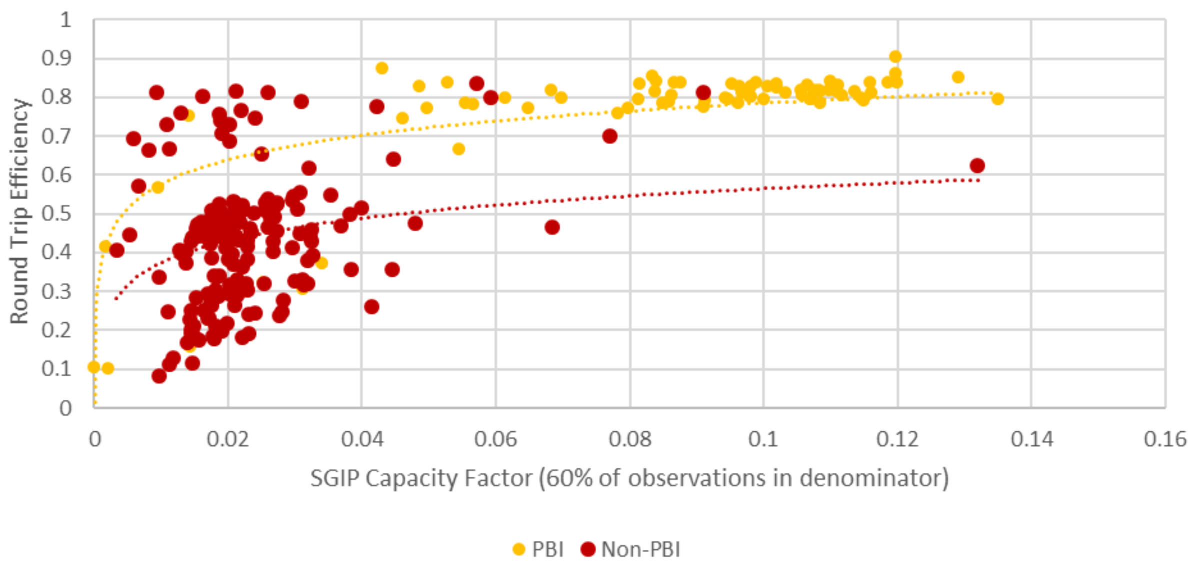
6 AES systems must maintain a round trip efficiency equal to or greater than 69.6% in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5%, assuming a 1% annual degradation rate. (2016 SGIP Handbook, https://www.selfgenca.com/documents/handbook/2016)

FIGURE 3-12: ROUNDTRIP EFFICIENCY FOR NON-RESIDENTIAL PROJECTS (2016) – 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 apparent in Figure 3-13. Systems with the lowest capacity factors tend to have the lowest RTEs.

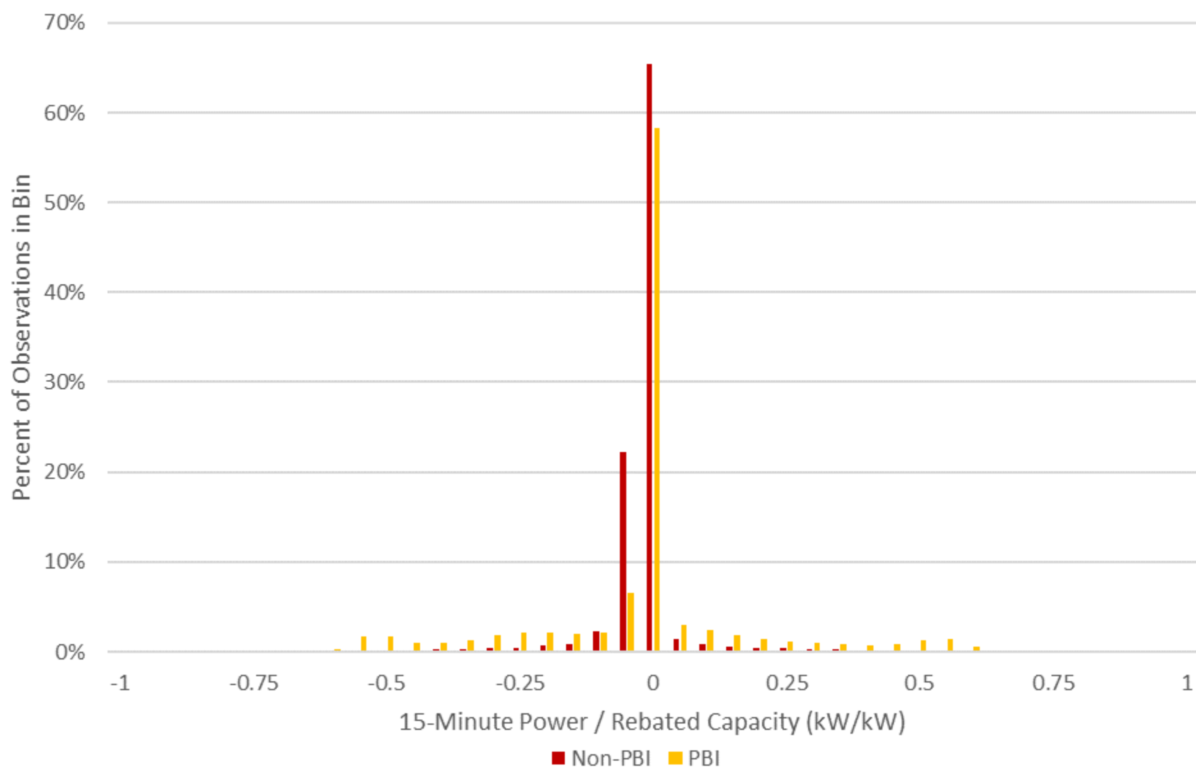
FIGURE 3-13: TOTAL ROUNDTRIP EFFICIENCY VERSUS CAPACITY FACTORS (ALL NONRESIDENTIAL PROJECTS)



We also examined the dispatch performance of the storage systems relative to the rebated capacity of the systems. Figure 3-14 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 2016, 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 (22%) 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 3-14: HISTOGRAM OF NON-PBI AND PBI NORMALIZED 15-MINUTE POWER



3.4.2 Influence of Parasitic Loads on Performance

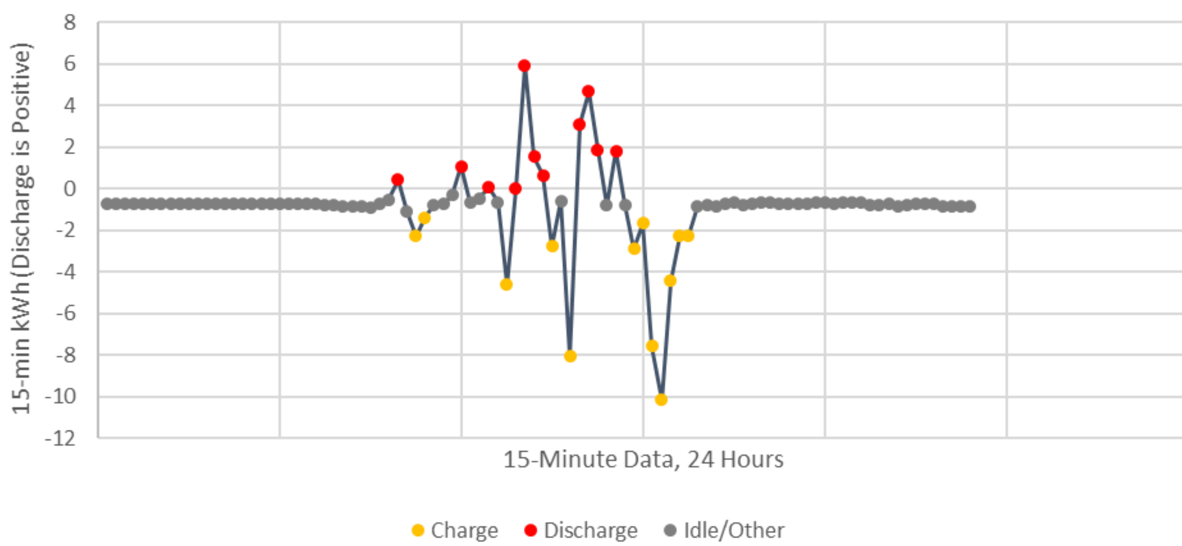
The mean observed RTE for non-PBI projects (44%) was far lower than for PBI projects (74%). Likewise, Figure 3-13 provided evidence that these systems were under-utilized with capacity factors generally ranging from 0.01 to 0.04. One consequence of this is standby losses and parasitic loads associated 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:

- Charge – any 15-minute charge (-) event greater than or equal to 5% of rebated capacity
- Discharge – any 15-minute discharge (+) event
- Idle/Other – any 15-minute charge (-) event less than 5% of rebated capacity.[8]

[8] 5% was used across all projects to represent any potential parasitic. This exercise was conducted to be instructive only. Parasitic losses vary from project to project.

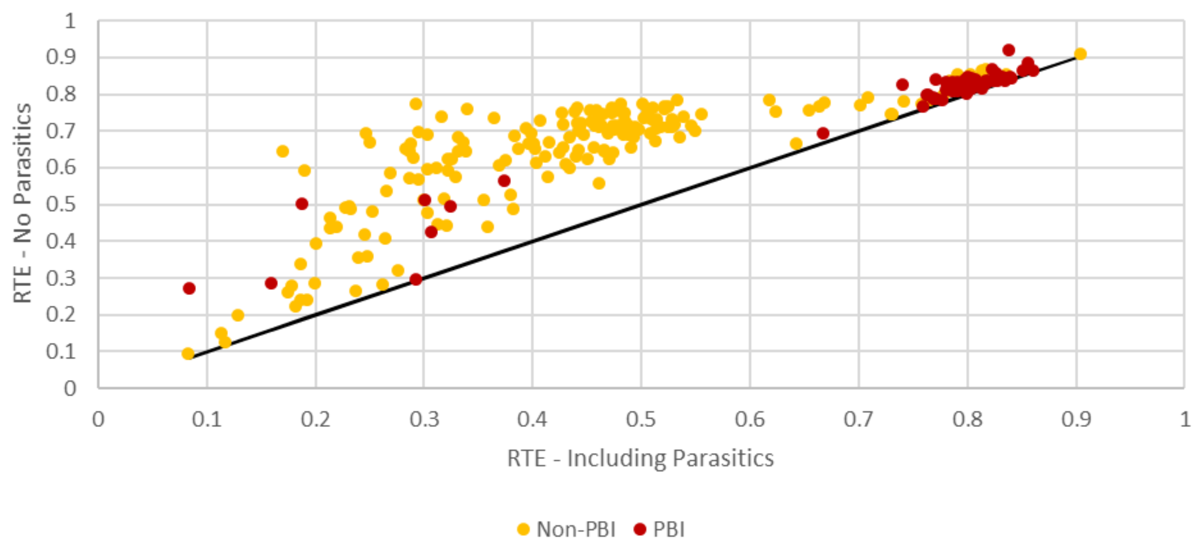
Figure 3-15 presents a graphical representation of charge, discharge and idle/other designation. The 15-minute charge and discharge events are evident in the data. However, periods of inactivity (highlighted in gray) represent a small discharge throughout the metering period. While the charge level is small at the 15-minute level, over the course of year, the impacts can become substantial, especially for a system that is under-utilized.

FIGURE 3-15: EXAMPLE CLASSIFICATION OF 15 MINUTE POWER KW CHARGE/DISCHARGE/IDLE



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 non-residential projects to assess the influence of those "idle" hours. The results of that analysis are presented below in Figure 3-16. 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 red. However, for many of the non-PBI systems, those with RTEs in the 40% to 50% range, removal of the parasitic loads has a substantial impact on the performance of the system. Projects in the 40% to 50% range would exhibit RTEs in the 60% to 80% range if the parasitic loads were removed.

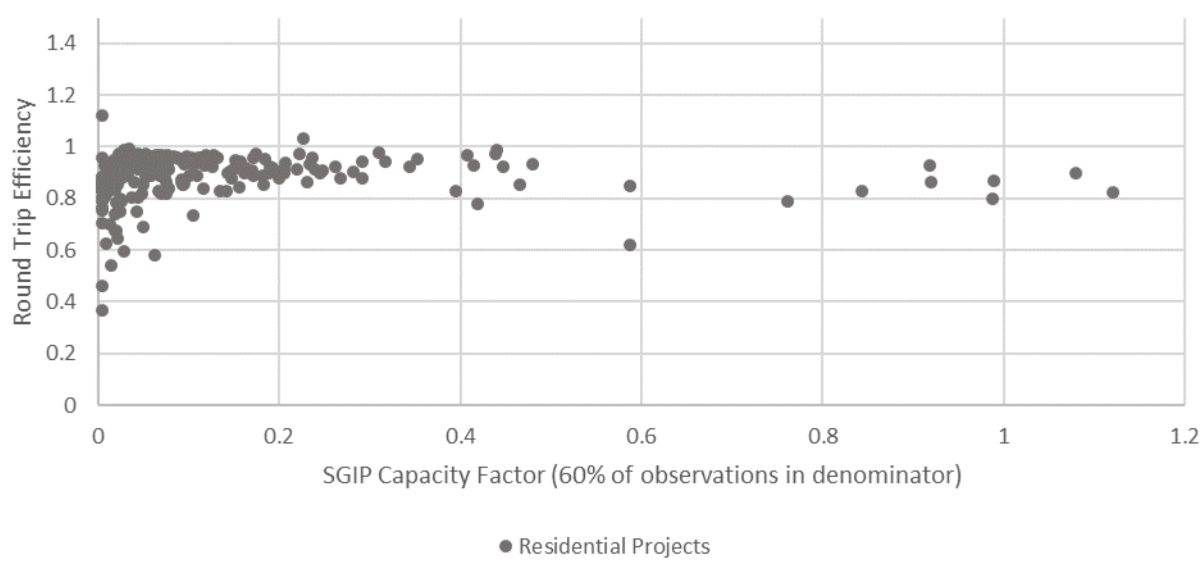
FIGURE 3-16: INFLUENCE OF PARASITICS ON ROUNDTRIP EFFICIENCY



Residential Projects

As discussed in Section 3.3, data quality issues limited our ability to fully assess the performance of residential storage systems. Even though we were unable to quantify performance impacts for residential projects, we conducted a qualitative assessment of the projects. Review of the residential data yielded a dataset of 327 projects.

FIGURE 3-17: TOTAL ROUNDTRIP EFFICIENCY VERSUS CAPACITY FACTORS (ALL RESIDENTIAL PROJECTS)



As evident in Figure 3-17, a significant number of projects (30%) exhibited a RTE of greater than 95%. Likewise, 10% of projects exhibited CF of greater than 50%.[9] Note that Figure 3-17 excludes residential projects already discarded from the analysis dataset due to extremely high RTEs.

3.5 CUSTOMER IMPACTS

Non-Residential Projects

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.[10] 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 3-18 provides the TOU periods 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.

[9] The x and y axis were both cropped to allow for data presentment. Some RTEs and CFs extended well above 10.0.

[10] There was one additional project in the sample that had a municipal rate. The evaluation team did not have rate information for this customer.

FIGURE 3-18: TIME-OF-USE PERIODS BY IOU

	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 (period ending). 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 6 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)
- Overall customer bill savings ($/rebated kW) by rate group and project type

- Overall storage dispatch behavior for customers on a specific peak demand period rate called critical peak pricing (CPP)

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 3-19 and Figure 3-20 present the discharge behavior for all 259 non-residential projects during the summer TOU period for non-PBI and PBI projects, respectively. Figure 3-21 and Figure 3-22 present storage discharge by winter TOU period. Only one utility has a commercial peak period rate during the winter.

FIGURE 3-19: 2016 SGIP NON-RESIDENTIAL NON-PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD

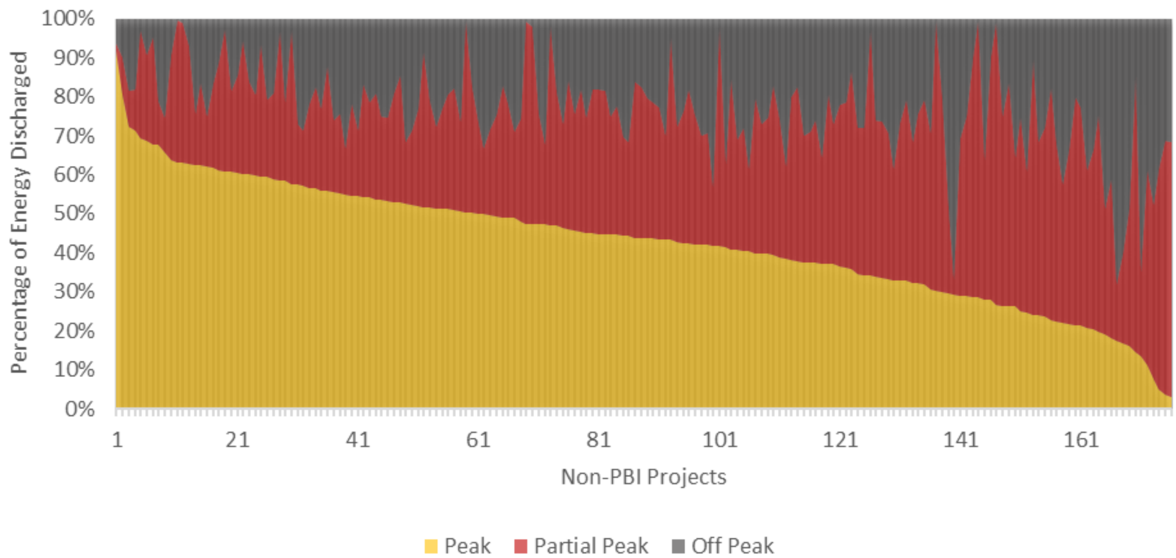


FIGURE 3-20: 2016 SGIP NON-RESIDENTIAL PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD

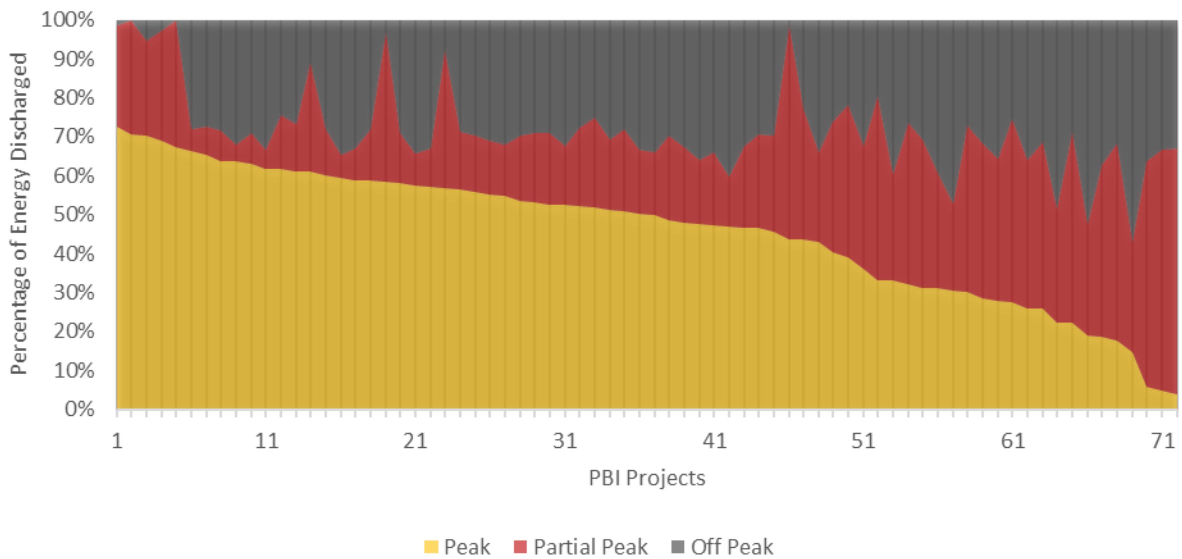


FIGURE 3-21: 2016 SGIP NON-RESIDENTIAL NON-PBI PROJECT DISCHARGE BY WINTER TOU PERIOD

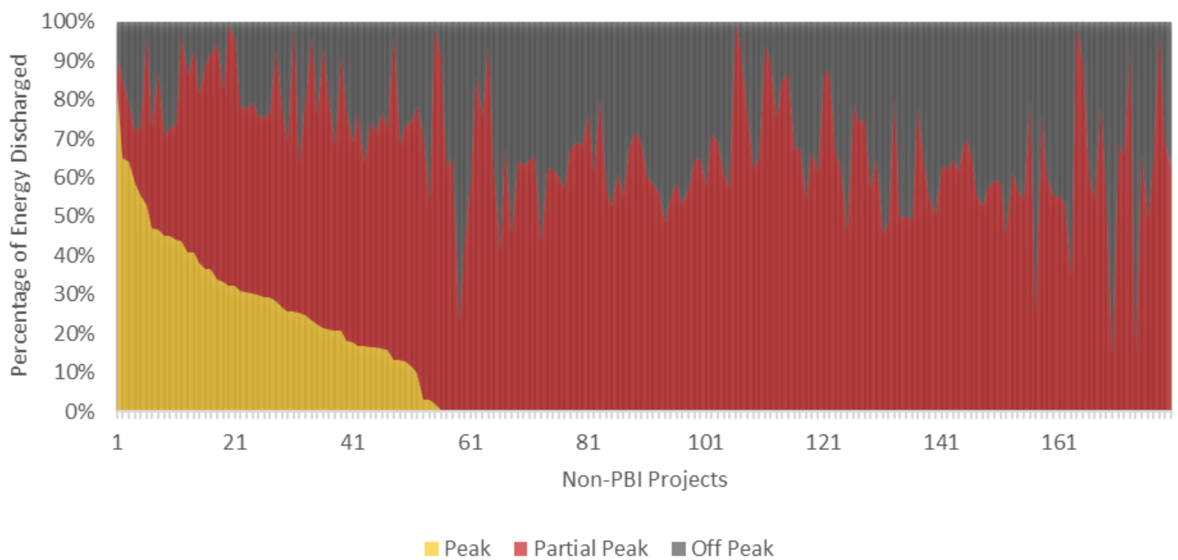
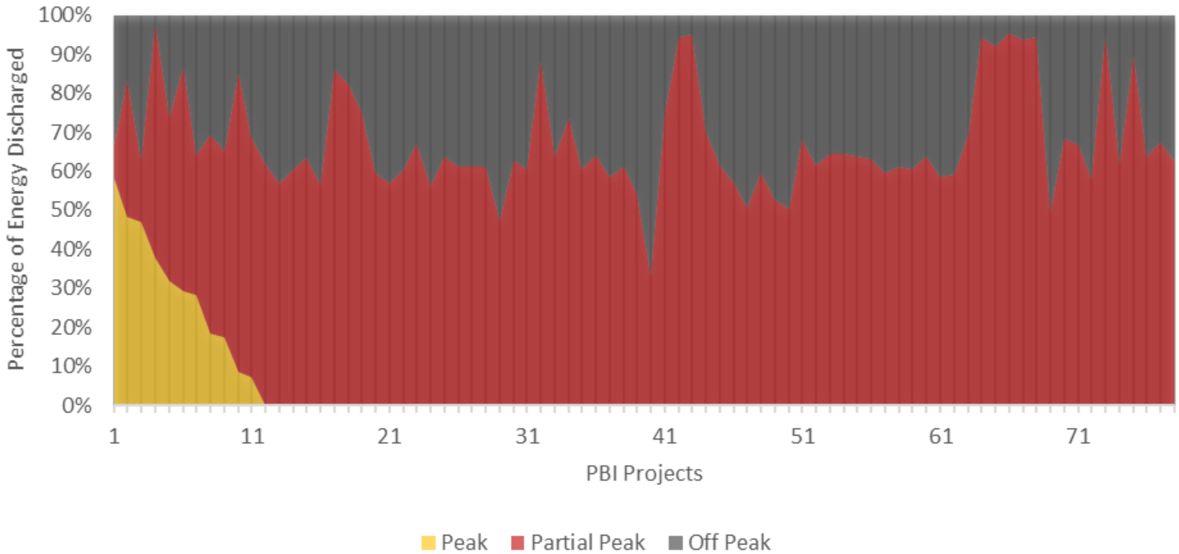


FIGURE 3-22: 2016 SGIP NON-RESIDENTIAL PBI PROJECT DISCHARGE BY WINTER TOU PERIOD



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-one non-PBI projects (TOU analysis was not conducted on one of the 181 non-PBI projects) discharged 50% or more of their storage energy during the summer peak period. Thirty-six PBI projects (4 of the 78 total projects were not included in the summer TOU analysis because they came on-line late in the year) discharged 50% or more of their storage energy during the summer peak period. We will discuss how customer rate structures may have had an impact on energy discharge during peak periods in the following section.

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 (-0.065 average hourly kW per rebated capacity (kW/kW)) and discharging during peak hours (0.114 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.

FIGURE 3-23: HOURLY NET DISCHARGE KW PER REBATED KW BY SUMMER TOU PERIOD

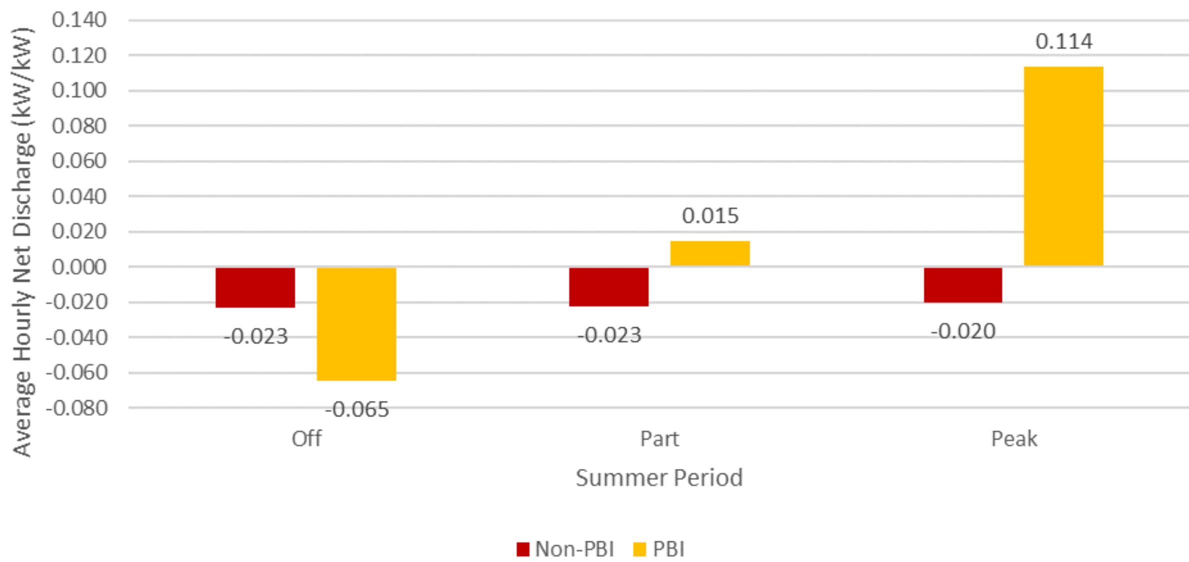
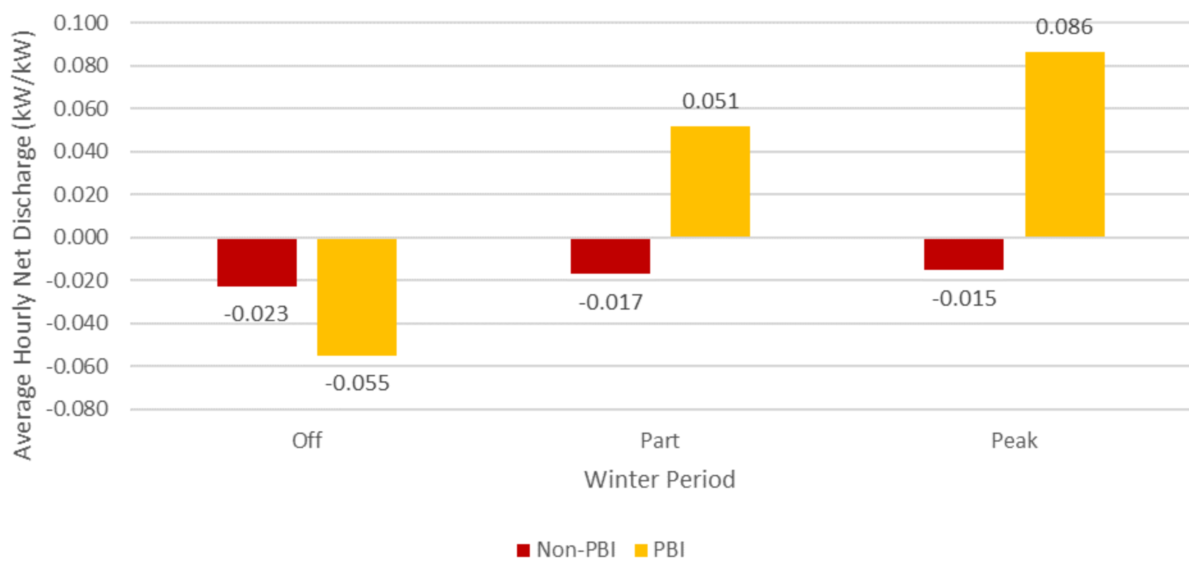


FIGURE 3-24: HOURLY NET DISCHARGE KW PER REBATED KW BY WINTER TOU PERIOD



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 3-25 and Figure 3-26 present the findings for PBI projects. Discharging is positive and is shown in green and charging is negative and is shown in red.

FIGURE 3-25: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.004	0.004	0.003	0.004	0.004	0.001	0.001	0.002	0.005	0.005	0.003	0.002
1	0.003	0.004	0.004	0.005	0.006	0.002	0.001	0.001	0.004	0.004	0.003	0.002
2	0.002	0.005	0.004	0.005	0.003	0.002	0.001	0.001	0.003	0.004	0.002	0.001
3	0.002	0.004	0.003	0.005	0.003	0.003	0.001	0.002	0.003	0.005	0.002	0.001
4	0.003	0.004	0.004	0.006	0.006	0.005	0.002	0.003	0.005	0.005	0.003	0.001
5	0.006	0.006	0.009	0.010	0.009	0.005	0.006	0.003	0.007	0.006	0.004	0.004
6	0.012	0.022	0.026	0.029	0.025	0.020	0.017	0.019	0.020	0.023	0.021	0.021
7	0.019	0.040	0.041	0.037	0.031	0.025	0.025	0.026	0.023	0.025	0.025	0.021
8	0.020	0.014	0.017	0.030	0.020	0.017	0.016	0.012	0.013	0.014	0.024	0.020
9	0.031	0.034	0.025	0.044	0.026	0.027	0.024	0.019	0.020	0.022	0.046	0.038
10	0.026	0.033	0.025	0.039	0.037	0.035	0.033	0.031	0.029	0.029	0.048	0.040
11	0.020	0.028	0.026	0.046	0.069	0.073	0.065	0.061	0.067	0.067	0.053	0.046
12	0.027	0.025	0.030	0.044	0.071	0.079	0.074	0.074	0.073	0.073	0.046	0.036
13	0.029	0.020	0.028	0.040	0.072	0.084	0.083	0.089	0.086	0.078	0.041	0.034
14	0.029	0.023	0.026	0.036	0.106	0.164	0.149	0.162	0.138	0.100	0.049	0.034
15	0.037	0.027	0.034	0.035	0.120	0.180	0.163	0.183	0.150	0.098	0.054	0.041
16	0.039	0.036	0.048	0.054	0.138	0.184	0.181	0.201	0.156	0.116	0.061	0.052
17	0.056	0.047	0.098	0.130	0.089	0.054	0.067	0.061	0.064	0.117	0.088	0.080
18	0.094	0.084	0.181	0.213	0.146	0.121	0.128	0.115	0.142	0.202	0.143	0.123
19	0.149	0.155	0.221	0.249	0.183	0.151	0.146	0.134	0.168	0.203	0.199	0.189
20	0.166	0.183	0.176	0.147	0.125	0.133	0.119	0.108	0.128	0.132	0.196	0.204
21	0.060	0.068	0.045	0.019	0.023	0.033	0.031	0.034	0.024	0.010	0.086	0.106
22	0.014	0.011	0.029	0.040	0.034	0.036	0.039	0.031	0.036	0.041	0.020	0.016
23	0.042	0.032	0.017	0.006	0.005	0.003	0.003	0.001	0.003	0.004	0.036	0.049

FIGURE 3-26: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.174	-0.171	-0.194	-0.190	-0.216	-0.264	-0.260	-0.257	-0.251	-0.234	-0.239	-0.236
1	-0.154	-0.143	-0.153	-0.145	-0.156	-0.182	-0.188	-0.186	-0.182	-0.154	-0.210	-0.201
2	-0.107	-0.103	-0.105	-0.102	-0.116	-0.114	-0.101	-0.097	-0.104	-0.098	-0.150	-0.144
3	-0.060	-0.063	-0.068	-0.070	-0.083	-0.074	-0.063	-0.050	-0.059	-0.064	-0.100	-0.108
4	-0.050	-0.045	-0.053	-0.050	-0.061	-0.053	-0.045	-0.031	-0.035	-0.041	-0.063	-0.072
5	-0.038	-0.031	-0.043	-0.040	-0.044	-0.037	-0.034	-0.024	-0.023	-0.029	-0.042	-0.050
6	-0.027	-0.024	-0.035	-0.035	-0.032	-0.025	-0.026	-0.018	-0.018	-0.022	-0.029	-0.032
7	-0.022	-0.022	-0.026	-0.026	-0.022	-0.020	-0.019	-0.014	-0.017	-0.016	-0.022	-0.023
8	-0.015	-0.029	-0.028	-0.029	-0.021	-0.019	-0.019	-0.020	-0.017	-0.018	-0.023	-0.021
9	-0.021	-0.038	-0.039	-0.040	-0.032	-0.025	-0.027	-0.028	-0.025	-0.026	-0.032	-0.031
10	-0.022	-0.025	-0.029	-0.031	-0.027	-0.027	-0.021	-0.022	-0.023	-0.024	-0.029	-0.028
11	-0.024	-0.022	-0.022	-0.022	-0.019	-0.010	-0.011	-0.012	-0.014	-0.020	-0.023	-0.021
12	-0.015	-0.017	-0.020	-0.022	-0.014	-0.010	-0.008	-0.008	-0.011	-0.017	-0.019	-0.019
13	-0.014	-0.016	-0.018	-0.020	-0.011	-0.012	-0.008	-0.009	-0.011	-0.016	-0.017	-0.017
14	-0.020	-0.014	-0.018	-0.017	-0.012	-0.019	-0.019	-0.015	-0.018	-0.021	-0.015	-0.013
15	-0.020	-0.014	-0.018	-0.018	-0.011	-0.020	-0.018	-0.014	-0.017	-0.017	-0.014	-0.010
16	-0.019	-0.013	-0.017	-0.019	-0.010	-0.011	-0.010	-0.011	-0.015	-0.014	-0.011	-0.011
17	-0.014	-0.011	-0.014	-0.015	-0.012	-0.019	-0.021	-0.026	-0.026	-0.021	-0.011	-0.011
18	-0.014	-0.014	-0.015	-0.014	-0.011	-0.011	-0.011	-0.013	-0.014	-0.015	-0.018	-0.014
19	-0.011	-0.012	-0.019	-0.015	-0.009	-0.009	-0.010	-0.012	-0.012	-0.016	-0.019	-0.013
20	-0.022	-0.013	-0.033	-0.051	-0.055	-0.043	-0.041	-0.048	-0.043	-0.062	-0.027	-0.016
21	-0.035	-0.034	-0.069	-0.122	-0.144	-0.136	-0.138	-0.135	-0.135	-0.171	-0.052	-0.034
22	-0.130	-0.146	-0.137	-0.163	-0.189	-0.231	-0.210	-0.227	-0.211	-0.193	-0.172	-0.181
23	-0.078	-0.107	-0.175	-0.230	-0.269	-0.317	-0.304	-0.306	-0.289	-0.278	-0.172	-0.155

PBI projects illustrate a clear signature of charge and discharge throughout the year. During the summer months, they discharge, on average, more significantly during the hours of 3 pm through 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 3-27 and Figure 3-28 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 shaving. One other important caveat is that hotels represent a significant share of non-PBI projects, both in terms of project count (50%) and rebated capacity (44%). The load shape profile of this building type is significantly different than the load shape of an industrial facility, for example. Appendix C provides charge and discharge heat maps by building type for PBI and non-PBI projects.

FIGURE 3-27: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.082	0.055	0.034	0.014	0.027	0.047	0.042	0.048	0.052	0.048	0.034	0.042
1	0.048	0.033	0.034	0.008	0.010	0.018	0.005	0.007	0.008	0.007	0.042	0.038
2	0.051	0.030	0.020	0.007	0.011	0.010	0.005	0.007	0.008	0.005	0.007	0.013
3	0.028	0.023	0.018	0.004	0.012	0.009	0.005	0.007	0.007	0.009	0.005	0.014
4	0.022	0.015	0.022	0.015	0.021	0.017	0.013	0.010	0.009	0.013	0.009	0.017
5	0.026	0.023	0.031	0.027	0.029	0.025	0.021	0.024	0.031	0.029	0.022	0.029
6	0.062	0.048	0.047	0.037	0.041	0.038	0.036	0.038	0.027	0.025	0.037	0.044
7	0.067	0.056	0.060	0.056	0.063	0.068	0.062	0.068	0.057	0.046	0.051	0.050
8	0.067	0.055	0.056	0.045	0.057	0.061	0.055	0.047	0.043	0.035	0.048	0.050
9	0.071	0.068	0.060	0.063	0.070	0.077	0.067	0.058	0.066	0.052	0.060	0.043
10	0.070	0.059	0.066	0.064	0.076	0.100	0.083	0.073	0.089	0.062	0.065	0.040
11	0.063	0.067	0.068	0.058	0.076	0.102	0.077	0.074	0.093	0.062	0.064	0.036
12	0.073	0.067	0.063	0.065	0.073	0.092	0.079	0.070	0.078	0.061	0.073	0.045
13	0.073	0.080	0.070	0.064	0.074	0.088	0.072	0.068	0.076	0.063	0.066	0.036
14	0.060	0.081	0.069	0.060	0.071	0.081	0.072	0.077	0.076	0.061	0.060	0.029
15	0.055	0.068	0.065	0.062	0.072	0.082	0.079	0.103	0.072	0.060	0.053	0.034
16	0.054	0.060	0.074	0.095	0.079	0.083	0.100	0.076	0.093	0.053	0.070	0.046
17	0.110	0.100	0.066	0.071	0.057	0.072	0.072	0.061	0.068	0.045	0.093	0.074
18	0.101	0.112	0.098	0.094	0.061	0.074	0.064	0.064	0.078	0.061	0.089	0.078
19	0.089	0.097	0.102	0.096	0.085	0.079	0.065	0.071	0.064	0.055	0.078	0.072
20	0.073	0.076	0.078	0.073	0.081	0.074	0.063	0.055	0.049	0.042	0.059	0.056
21	0.042	0.042	0.036	0.030	0.033	0.030	0.028	0.020	0.018	0.016	0.033	0.040
22	0.036	0.030	0.024	0.016	0.017	0.026	0.015	0.012	0.013	0.009	0.021	0.033
23	0.018	0.014	0.032	0.053	0.041	0.054	0.039	0.035	0.045	0.039	0.016	0.022

FIGURE 3-28: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.031	-0.035	-0.039	-0.038	-0.039	-0.044	-0.035	-0.034	-0.037	-0.035	-0.037	-0.038
1	-0.031	-0.032	-0.029	-0.028	-0.028	-0.030	-0.027	-0.027	-0.029	-0.027	-0.034	-0.039
2	-0.027	-0.027	-0.024	-0.024	-0.023	-0.024	-0.022	-0.022	-0.023	-0.022	-0.026	-0.030
3	-0.023	-0.022	-0.022	-0.022	-0.023	-0.022	-0.022	-0.022	-0.023	-0.021	-0.023	-0.024
4	-0.023	-0.022	-0.021	-0.022	-0.022	-0.022	-0.021	-0.022	-0.022	-0.021	-0.022	-0.021
5	-0.021	-0.020	-0.022	-0.022	-0.022	-0.023	-0.022	-0.023	-0.024	-0.022	-0.021	-0.021
6	-0.022	-0.022	-0.024	-0.023	-0.024	-0.025	-0.022	-0.023	-0.024	-0.023	-0.022	-0.022
7	-0.029	-0.026	-0.026	-0.025	-0.026	-0.029	-0.025	-0.026	-0.026	-0.024	-0.025	-0.027
8	-0.023	-0.022	-0.024	-0.022	-0.024	-0.023	-0.022	-0.022	-0.022	-0.020	-0.023	-0.027
9	-0.035	-0.031	-0.036	-0.035	-0.041	-0.043	-0.039	-0.037	-0.031	-0.027	-0.033	-0.036
10	-0.050	-0.043	-0.038	-0.038	-0.042	-0.046	-0.040	-0.039	-0.035	-0.028	-0.034	-0.035
11	-0.049	-0.045	-0.039	-0.034	-0.043	-0.043	-0.043	-0.040	-0.039	-0.031	-0.036	-0.034
12	-0.045	-0.038	-0.037	-0.034	-0.040	-0.047	-0.040	-0.039	-0.041	-0.032	-0.036	-0.033
13	-0.038	-0.035	-0.036	-0.034	-0.041	-0.049	-0.043	-0.039	-0.041	-0.033	-0.037	-0.030
14	-0.038	-0.037	-0.038	-0.037	-0.046	-0.052	-0.047	-0.045	-0.043	-0.035	-0.039	-0.029
15	-0.037	-0.040	-0.038	-0.037	-0.048	-0.051	-0.049	-0.047	-0.045	-0.039	-0.043	-0.028
16	-0.034	-0.045	-0.042	-0.039	-0.048	-0.058	-0.049	-0.061	-0.049	-0.044	-0.043	-0.028
17	-0.034	-0.043	-0.041	-0.044	-0.057	-0.070	-0.069	-0.064	-0.067	-0.043	-0.037	-0.026
18	-0.040	-0.045	-0.042	-0.046	-0.051	-0.069	-0.063	-0.048	-0.047	-0.037	-0.047	-0.034
19	-0.048	-0.053	-0.054	-0.057	-0.044	-0.058	-0.051	-0.040	-0.045	-0.038	-0.056	-0.039
20	-0.067	-0.064	-0.049	-0.049	-0.054	-0.059	-0.047	-0.045	-0.049	-0.047	-0.061	-0.046
21	-0.050	-0.047	-0.043	-0.042	-0.047	-0.044	-0.045	-0.035	-0.037	-0.032	-0.041	-0.033
22	-0.046	-0.051	-0.055	-0.050	-0.058	-0.056	-0.050	-0.040	-0.044	-0.037	-0.050	-0.043
23	-0.040	-0.043	-0.048	-0.042	-0.045	-0.048	-0.038	-0.034	-0.037	-0.033	-0.045	-0.041

Figure 3-29 and Figure 3-30 below combine the discharge and charge data for both PBI and non-PBI projects. The combined results are similar to PBI project findings given the much more significant sizing of those systems.

FIGURE 3-29: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NON-RES PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.039	0.023	0.013	0.007	0.011	0.015	0.012	0.014	0.017	0.016	0.011	0.015
1	0.021	0.014	0.013	0.006	0.007	0.006	0.002	0.002	0.005	0.005	0.013	0.013
2	0.022	0.013	0.009	0.005	0.005	0.004	0.002	0.003	0.004	0.004	0.003	0.004
3	0.012	0.010	0.008	0.005	0.006	0.005	0.002	0.003	0.004	0.006	0.003	0.005
4	0.011	0.008	0.010	0.009	0.011	0.009	0.005	0.005	0.006	0.007	0.005	0.006
5	0.015	0.013	0.018	0.016	0.017	0.011	0.011	0.009	0.014	0.013	0.010	0.013
6	0.040	0.034	0.035	0.032	0.031	0.026	0.023	0.025	0.022	0.024	0.027	0.030
7	0.047	0.048	0.050	0.046	0.045	0.043	0.039	0.042	0.035	0.032	0.034	0.033
8	0.045	0.032	0.035	0.037	0.037	0.036	0.033	0.025	0.024	0.021	0.032	0.032
9	0.054	0.051	0.042	0.053	0.048	0.051	0.044	0.036	0.039	0.034	0.051	0.040
10	0.051	0.047	0.045	0.051	0.056	0.067	0.056	0.050	0.055	0.042	0.055	0.040
11	0.044	0.049	0.047	0.052	0.073	0.088	0.071	0.067	0.079	0.065	0.057	0.042
12	0.053	0.048	0.047	0.054	0.072	0.086	0.077	0.072	0.075	0.068	0.058	0.039
13	0.054	0.054	0.049	0.052	0.073	0.086	0.077	0.078	0.081	0.072	0.052	0.035
14	0.047	0.057	0.048	0.049	0.087	0.119	0.108	0.118	0.107	0.083	0.053	0.032
15	0.047	0.051	0.050	0.049	0.094	0.125	0.118	0.141	0.112	0.082	0.054	0.038
16	0.047	0.049	0.062	0.077	0.106	0.128	0.137	0.137	0.126	0.090	0.065	0.050
17	0.093	0.080	0.080	0.099	0.073	0.063	0.070	0.061	0.066	0.085	0.090	0.077
18	0.099	0.102	0.127	0.144	0.103	0.099	0.100	0.092	0.113	0.138	0.116	0.100
19	0.109	0.117	0.146	0.162	0.128	0.114	0.107	0.104	0.123	0.139	0.142	0.133
20	0.106	0.118	0.117	0.107	0.102	0.105	0.093	0.085	0.097	0.097	0.138	0.137
21	0.050	0.054	0.040	0.024	0.027	0.031	0.030	0.029	0.022	0.012	0.065	0.079
22	0.026	0.020	0.027	0.031	0.028	0.033	0.032	0.025	0.029	0.032	0.021	0.022
23	0.031	0.025	0.022	0.022	0.017	0.018	0.014	0.011	0.015	0.013	0.030	0.040

FIGURE 3-30: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NON-RES PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.057	-0.061	-0.071	-0.072	-0.084	-0.102	-0.096	-0.094	-0.097	-0.094	-0.099	-0.098
1	-0.053	-0.053	-0.055	-0.054	-0.060	-0.070	-0.070	-0.070	-0.072	-0.064	-0.088	-0.088
2	-0.041	-0.041	-0.041	-0.042	-0.047	-0.048	-0.044	-0.043	-0.046	-0.044	-0.064	-0.064
3	-0.029	-0.029	-0.032	-0.033	-0.038	-0.036	-0.033	-0.029	-0.033	-0.034	-0.046	-0.049
4	-0.027	-0.026	-0.028	-0.028	-0.032	-0.030	-0.028	-0.024	-0.026	-0.027	-0.034	-0.037
5	-0.024	-0.022	-0.027	-0.026	-0.028	-0.027	-0.025	-0.023	-0.023	-0.024	-0.027	-0.030
6	-0.023	-0.022	-0.026	-0.026	-0.026	-0.025	-0.023	-0.022	-0.023	-0.023	-0.024	-0.025
7	-0.028	-0.025	-0.026	-0.026	-0.025	-0.026	-0.023	-0.023	-0.024	-0.021	-0.024	-0.026
8	-0.022	-0.023	-0.025	-0.023	-0.023	-0.022	-0.021	-0.022	-0.020	-0.020	-0.023	-0.025
9	-0.033	-0.032	-0.037	-0.036	-0.039	-0.038	-0.035	-0.035	-0.029	-0.027	-0.033	-0.035
10	-0.045	-0.039	-0.036	-0.036	-0.038	-0.041	-0.035	-0.034	-0.032	-0.026	-0.033	-0.033
11	-0.044	-0.040	-0.035	-0.031	-0.036	-0.034	-0.034	-0.032	-0.032	-0.028	-0.032	-0.030
12	-0.039	-0.034	-0.033	-0.031	-0.033	-0.037	-0.031	-0.031	-0.033	-0.028	-0.030	-0.029
13	-0.033	-0.031	-0.032	-0.031	-0.033	-0.039	-0.033	-0.031	-0.033	-0.028	-0.031	-0.026
14	-0.034	-0.032	-0.033	-0.033	-0.037	-0.043	-0.039	-0.036	-0.036	-0.031	-0.032	-0.024
15	-0.034	-0.035	-0.034	-0.032	-0.038	-0.043	-0.040	-0.038	-0.037	-0.032	-0.034	-0.023
16	-0.032	-0.039	-0.036	-0.034	-0.038	-0.045	-0.038	-0.047	-0.039	-0.035	-0.033	-0.022
17	-0.030	-0.037	-0.035	-0.038	-0.046	-0.056	-0.055	-0.054	-0.056	-0.036	-0.029	-0.021
18	-0.035	-0.039	-0.036	-0.039	-0.041	-0.053	-0.049	-0.039	-0.038	-0.030	-0.038	-0.028
19	-0.041	-0.045	-0.046	-0.047	-0.035	-0.045	-0.040	-0.032	-0.036	-0.031	-0.044	-0.031
20	-0.059	-0.054	-0.045	-0.049	-0.054	-0.055	-0.045	-0.046	-0.047	-0.052	-0.050	-0.037
21	-0.047	-0.045	-0.049	-0.061	-0.072	-0.069	-0.071	-0.063	-0.065	-0.073	-0.044	-0.033
22	-0.061	-0.069	-0.073	-0.075	-0.091	-0.103	-0.094	-0.091	-0.091	-0.083	-0.088	-0.085
23	-0.047	-0.055	-0.075	-0.085	-0.102	-0.120	-0.110	-0.108	-0.108	-0.105	-0.084	-0.075

While TOU arbitrage appears to be a motivation for on-peak discharge, monthly and TOU demand reduction 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 3-31). 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 3-27 and Figure 3-28. 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 3-31 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 3-32). Much like non-PBI projects, they are reducing their hourly load, on average, more substantially throughout the peak period, especially in the summer time (the valleys get deeper).

FIGURE 3-31: HOURLY LOAD FOR NON-PBI PROJECTS BY TOU PERIOD AND MONTH

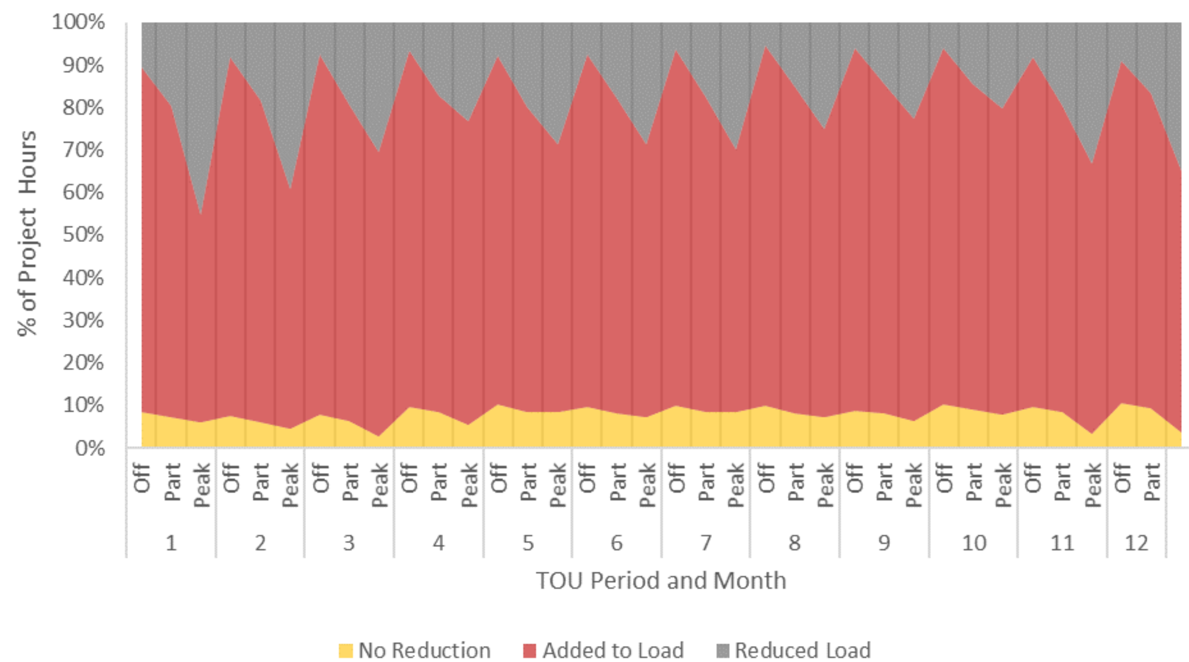
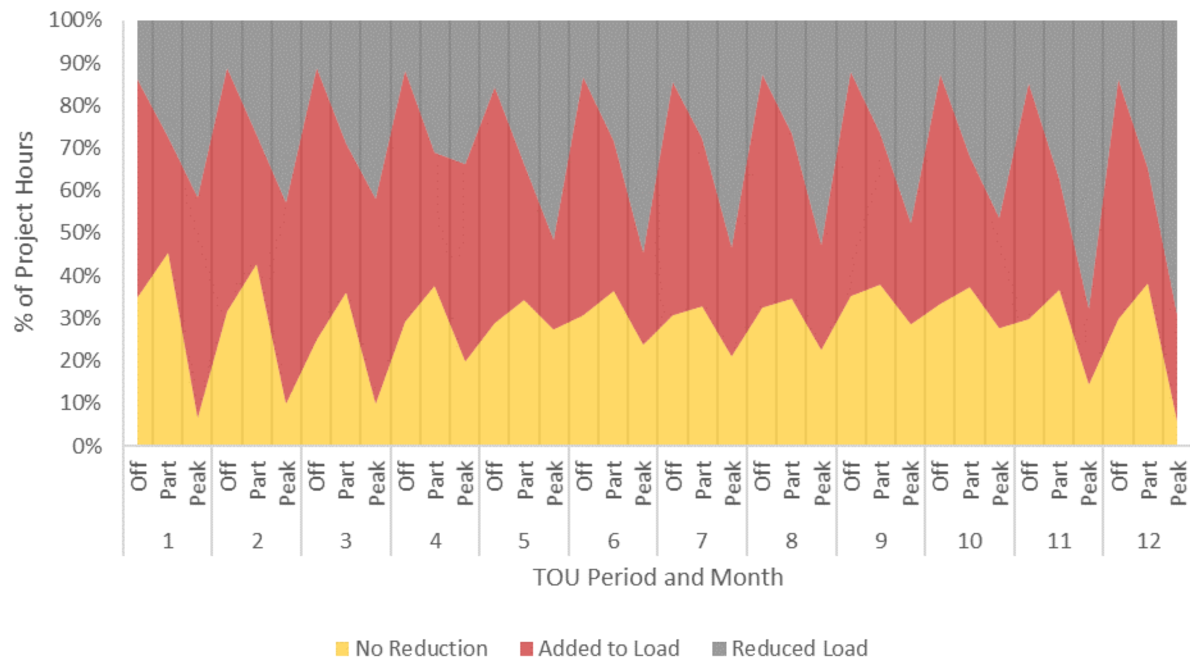
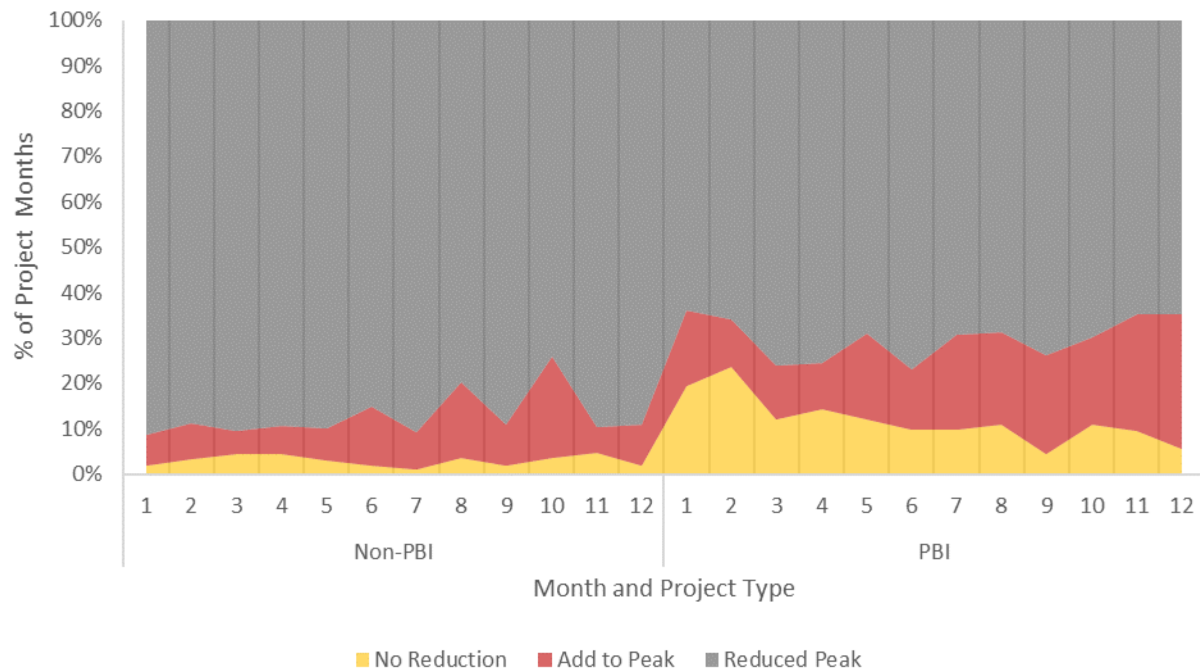


FIGURE 3-32: HOURLY LOAD FOR PBI PROJECTS BY TOU PERIOD AND MONTH



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 storage behavior. Figure 3-33 conveys those results. For non-PBI projects, storage dispatch resulted in significant reductions in monthly peak demand. In July, for example, 90% of projects (or project-months) experienced a reduction in peak demand. For PBI projects, there is a greater frequency of project-months with no peak demand reduction, especially in the early part of the year.

FIGURE 3-33: MONTHLY PEAK DEMAND FOR NON-PBI AND 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 3-34 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 44% of SGIP rebated capacity for non-PBI projects and 13% for PBI projects.

FIGURE 3-34: MONTHLY PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

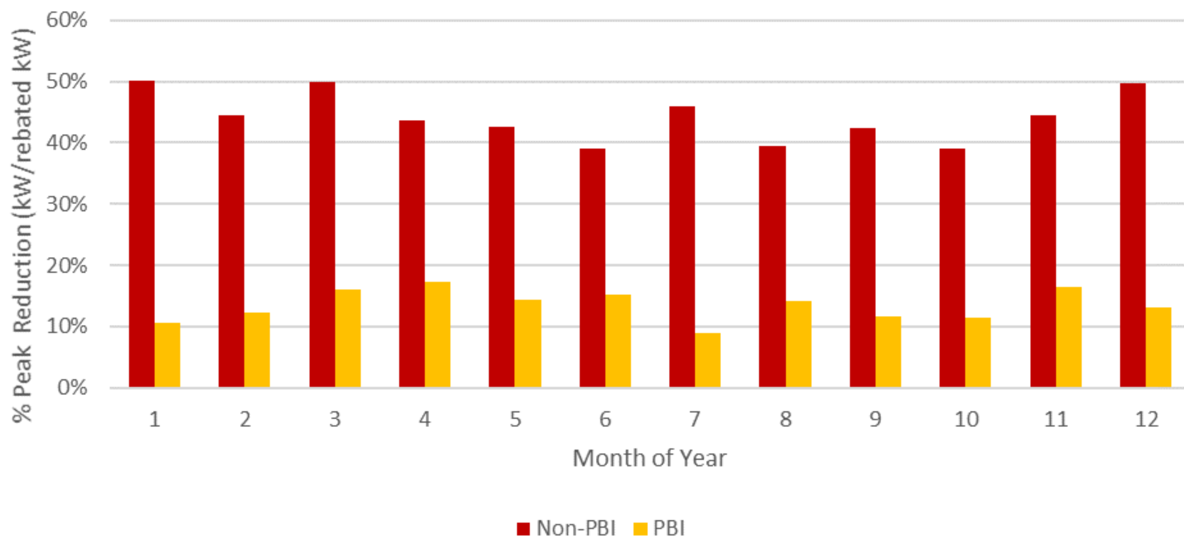
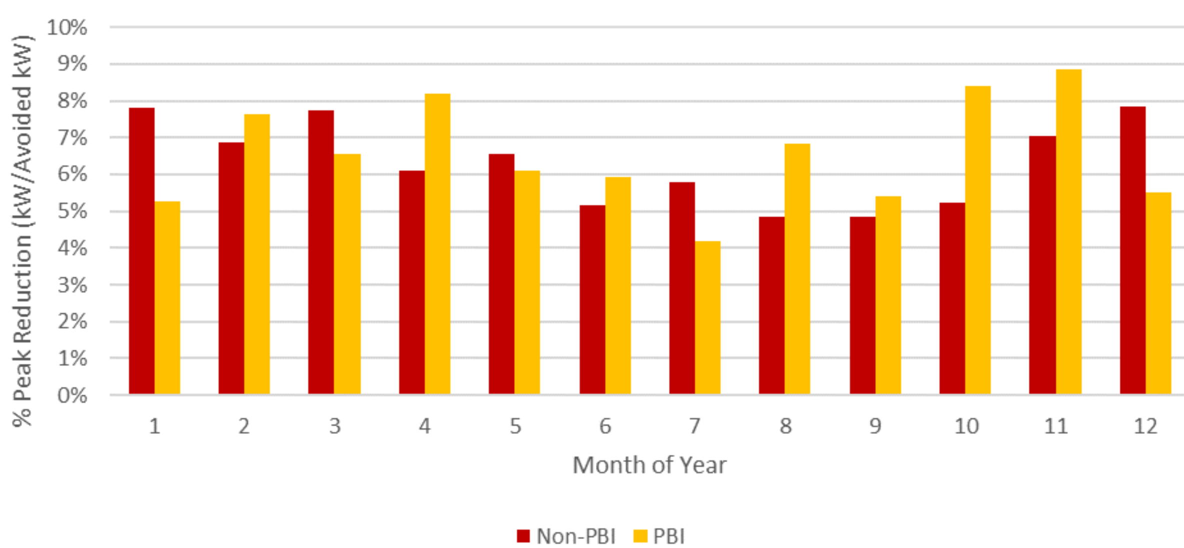


Figure 3-35 conveys the monthly average peak demand reduction as a percentage of the monthly avoided peak. In other words, if a customer's monthly peak demand would have been 100 kW in the absence of the storage system and they reduced peak demand by 10 kW with storage, then the customer reduced their peak demand by 10%. The results of this analysis suggest that non-PBI and PBI projects are reducing peak demand by a similar order of magnitude. On average, both PBI and non-PBI customers reduced their peak demand by 6%.

FIGURE 3-35: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW)



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 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 ($/kWh) depending on the period (off peak, partial peak or peak hours) and season (winter or summer)
- TOU Energy with Monthly Demand
  - This rate group includes customers on an energy rate as well as a monthly demand charge ($/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 an energy and 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 259 non-residential storage projects, we matched load and rate schedule data to 222 projects – 112 in PG&E, 45 in SCE and 65 in SDG&E.[11] Figure 3-36 and Figure 3-37 present the distribution of rate groups by project type. Overall, there were nine PBI projects on a TOU energy only rate, eight projects on a TOU and monthly demand rate, and 54 on a TOU, monthly, and peak demand rate. All but five of the 151 non-PBI projects were on a TOU, monthly, and peak demand rate.

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

FIGURE 3-36: RATE SCHEDULE GROUPS FOR PBI PROJECTS

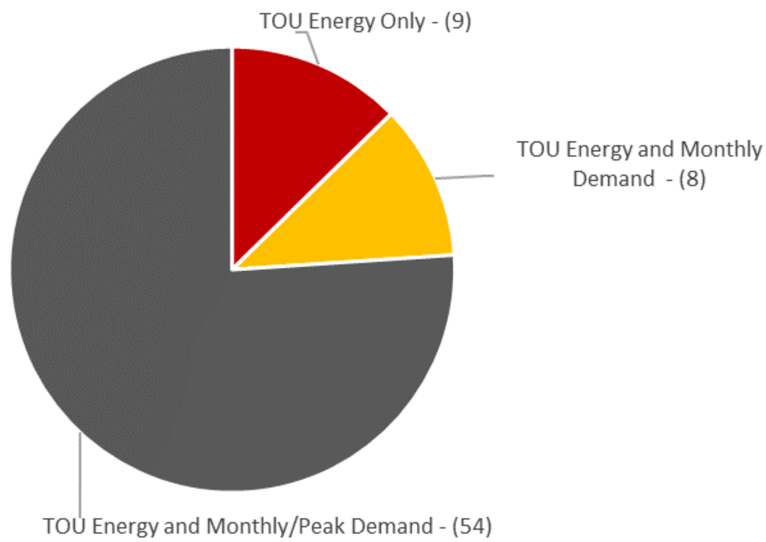
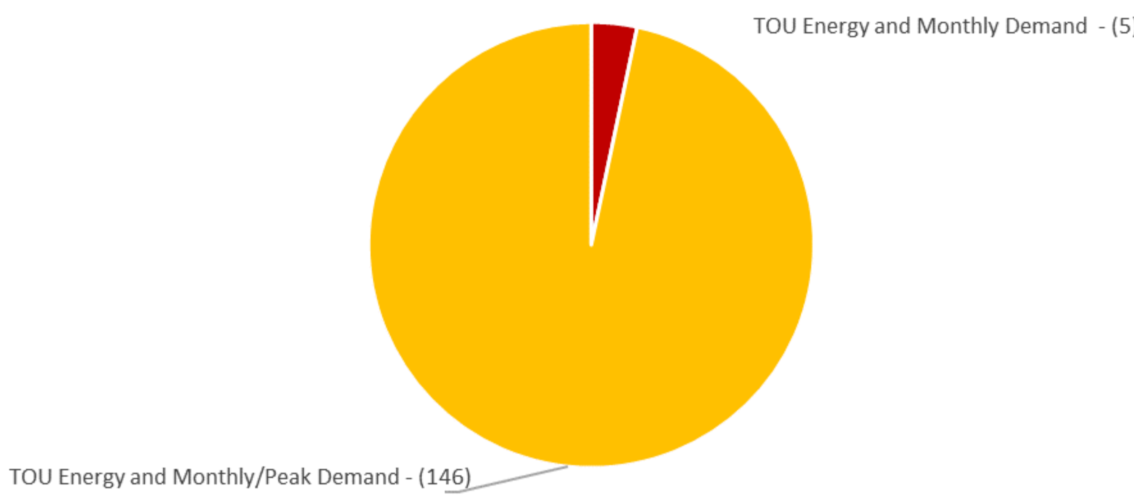


FIGURE 3-37: RATE SCHEDULE GROUPS FOR NON-PBI PROJECTS



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 nine projects on a TOU energy only rate and they were PBI projects located in PG&E territory. Figure 3-38 presents the average hourly discharge kW (per rebated capacity) for rates with energy and demand charges and Figure 3-39 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.[12]

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 substantially beginning in the early afternoon (2 to 3 pm) and ebbs in the late evening beginning around 10 pm. The early evening discharge is more substantial during the winter months.

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

[12] These data are presented in standard time, whereas the TOU periods presented in Figure 3-18 are presented in local time. TOU time periods begin and end one hour later during daylight savings time which occurred between 3/13 and 11/6 in 2016.

FIGURE 3-38: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NON-RESIDENTIAL PBI PROJECTS ON A TOU ENERGY AND DEMAND RATE (PG&E)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.003	0.005	0.004	0.005	0.005	0.001	0.001	0.002	0.006	0.006	0.003	0.002
1	0.003	0.005	0.005	0.006	0.007	0.002	0.001	0.001	0.004	0.005	0.003	0.002
2	0.002	0.006	0.005	0.006	0.004	0.002	0.001	0.001	0.003	0.005	0.002	0.001
3	0.002	0.005	0.004	0.006	0.004	0.003	0.001	0.002	0.003	0.005	0.002	0.001
4	0.004	0.005	0.004	0.007	0.006	0.006	0.002	0.003	0.005	0.005	0.003	0.001
5	0.004	0.008	0.011	0.011	0.008	0.004	0.007	0.002	0.006	0.006	0.004	0.004
6	0.006	0.027	0.031	0.034	0.024	0.020	0.018	0.021	0.021	0.024	0.022	0.021
7	0.013	0.047	0.044	0.031	0.025	0.021	0.021	0.025	0.022	0.024	0.024	0.021
8	0.009	0.007	0.012	0.015	0.015	0.012	0.011	0.011	0.011	0.011	0.018	0.015
9	0.015	0.015	0.016	0.024	0.022	0.019	0.016	0.018	0.018	0.020	0.034	0.028
10	0.020	0.015	0.019	0.030	0.034	0.031	0.030	0.029	0.028	0.029	0.040	0.030
11	0.021	0.013	0.020	0.037	0.055	0.048	0.047	0.044	0.054	0.055	0.048	0.037
12	0.027	0.017	0.024	0.041	0.061	0.056	0.056	0.058	0.061	0.061	0.042	0.032
13	0.023	0.019	0.026	0.041	0.068	0.070	0.071	0.079	0.082	0.074	0.040	0.032
14	0.025	0.026	0.027	0.038	0.104	0.173	0.155	0.168	0.145	0.100	0.049	0.032
15	0.041	0.030	0.039	0.038	0.125	0.200	0.181	0.206	0.164	0.099	0.055	0.043
16	0.044	0.040	0.055	0.065	0.147	0.210	0.205	0.229	0.174	0.120	0.064	0.058
17	0.065	0.054	0.113	0.157	0.102	0.061	0.077	0.069	0.069	0.130	0.098	0.092
18	0.107	0.096	0.207	0.253	0.170	0.131	0.142	0.126	0.153	0.219	0.162	0.143
19	0.172	0.177	0.256	0.297	0.213	0.165	0.161	0.146	0.183	0.220	0.216	0.215
20	0.193	0.213	0.206	0.174	0.145	0.148	0.135	0.122	0.141	0.142	0.210	0.230
21	0.068	0.079	0.052	0.023	0.027	0.040	0.038	0.042	0.028	0.012	0.095	0.123
22	0.017	0.013	0.034	0.049	0.040	0.042	0.045	0.036	0.041	0.047	0.023	0.018
23	0.047	0.036	0.020	0.007	0.005	0.002	0.003	0.001	0.004	0.004	0.041	0.057

FIGURE 3-39: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR ALL NON-RESIDENTIAL PBI PROJECTS ON A TOU ENERGY ONLY RATE (PG&E)

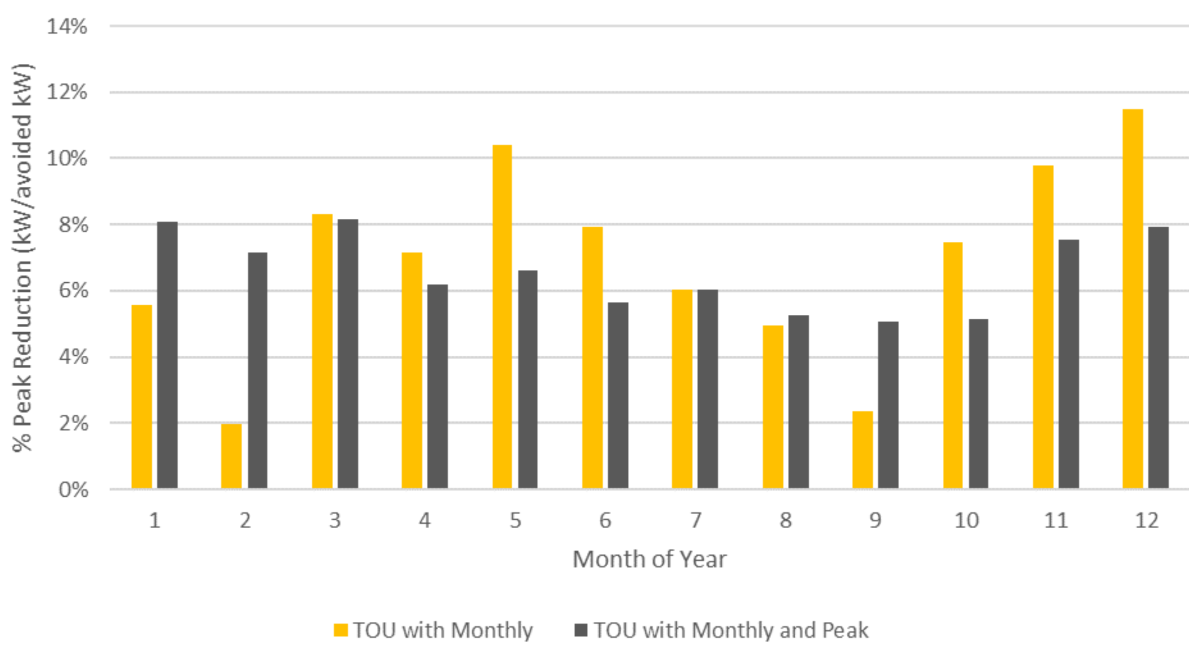
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.007	0.002	0.001	0.001	0.001	0.002	0.002	0.001	0.000	0.002	0.002	0.001
1	0.004	0.001	0.001	0.001	0.001	0.004	0.003	0.001	0.001	0.001	0.001	0.002
2	0.004	0.001	0.001	0.001	0.000	0.001	0.002	0.000	0.001	0.000	0.002	0.001
3	0.003	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.002	0.001
4	0.002	0.001	0.001	0.002	0.005	0.004	0.004	0.002	0.008	0.004	0.003	0.003
5	0.019	0.001	0.003	0.007	0.016	0.013	0.006	0.004	0.015	0.011	0.008	0.008
6	0.044	0.001	0.009	0.009	0.035	0.027	0.016	0.011	0.014	0.018	0.022	0.029
7	0.058	0.014	0.039	0.080	0.074	0.058	0.059	0.041	0.041	0.043	0.042	0.018
8	0.076	0.051	0.044	0.095	0.047	0.048	0.046	0.017	0.026	0.031	0.059	0.036
9	0.127	0.168	0.087	0.154	0.061	0.083	0.081	0.032	0.035	0.043	0.149	0.120
10	0.074	0.161	0.069	0.098	0.064	0.076	0.062	0.047	0.037	0.031	0.122	0.122
11	0.026	0.135	0.075	0.106	0.176	0.261	0.191	0.187	0.181	0.174	0.104	0.127
12	0.043	0.082	0.079	0.071	0.149	0.253	0.204	0.192	0.180	0.177	0.091	0.081
13	0.076	0.035	0.050	0.047	0.113	0.201	0.180	0.173	0.139	0.127	0.062	0.067
14	0.067	0.020	0.030	0.039	0.142	0.149	0.148	0.161	0.123	0.128	0.062	0.065
15	0.035	0.022	0.019	0.028	0.122	0.096	0.097	0.092	0.089	0.116	0.062	0.047
16	0.032	0.026	0.023	0.017	0.119	0.068	0.079	0.078	0.071	0.122	0.055	0.034
17	0.033	0.025	0.045	0.039	0.034	0.023	0.025	0.022	0.048	0.062	0.045	0.023
18	0.069	0.050	0.104	0.078	0.047	0.092	0.076	0.078	0.103	0.134	0.065	0.028
19	0.102	0.092	0.109	0.089	0.053	0.098	0.088	0.090	0.109	0.144	0.152	0.082
20	0.111	0.090	0.080	0.057	0.044	0.072	0.054	0.055	0.069	0.094	0.166	0.103
21	0.047	0.036	0.021	0.004	0.007	0.004	0.007	0.004	0.007	0.004	0.054	0.043
22	0.008	0.004	0.010	0.008	0.009	0.008	0.009	0.006	0.007	0.009	0.008	0.002
23	0.036	0.018	0.008	0.001	0.001	0.005	0.003	0.001	0.001	0.002	0.006	0.014

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 3-40 and Figure 3-41 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, but they only represent 5 of the 151 customers within that group. 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 3-40: PBI MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) BY RATE GROUP

FIGURE 3-41: NON-PBI MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW) BY RATE GROUP

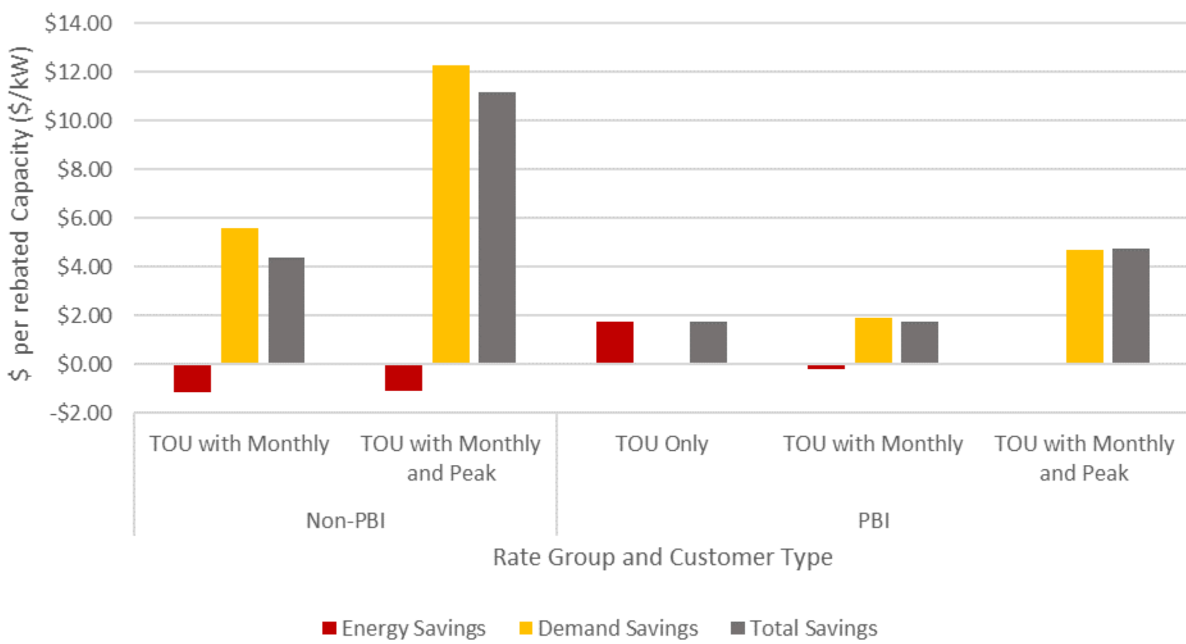


Overall Customer Bill Savings ($/kW) by Rate Group and Project Type

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 3-42 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. However, both groups realized more 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 3-42: CUSTOMER BILL SAVINGS ($/KW) BY RATE GROUP AND PBI/NON-PBI



Overall Storage Dispatch Behavior for Customers on Critical Peak Pricing (CPP) Schedules

We also examined storage dispatch behavior for customers on a special peak demand pricing rate called critical peak pricing. CPP rate schedules charge higher energy pricing during specific event periods when there is significant stress on the grid or there is an expectation of unusually high demand. These events generally coincide with utility peak demand periods and the rates are designed to influence customers to shift or reduce their demand during those periods.

During 2016, all three IOUs had a CPP tariff that was triggered. For PG&E and SCE, 12 events were executed throughout the summer and lasted from 2 pm to 6 pm, however, the event days did not necessarily coincide with one another for the two utilities. SDG&E called one event that lasted from 11 am to 6 pm.

After reviewing the rate schedules obtained for each of the SGIP storage customers, we confirmed 61 customers were on a CPP rate for at least one event throughout the year.[13] There were 16 customers in PG&E, 6 in SCE and 39 in SDG&E. We examined each customer's storage discharge behavior during these CPP 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 rate. Figure 3-43 and Figure 3-44 present those results.

It's important to note that, for both these summaries, the total number of projects on a CPP rate for PBI and non-PBI are not evenly distributed for each of the IOUs. For example, 15 of the 16 customers on a CPP rate in PG&E were non-PBI customers. For SCE, only one of six customers was non-PBI and for SDG&E, 33 of the 39 CPP customers represented non-PBI projects. For PG&E non-PBI customers, there is little difference in dispatch behavior when comparing CPP event periods and non-event periods. Given the sample size of one for non-PBI SCE customers, no real trends can be gleaned from the data. SDG&E customers, however, are discharging, on average, throughout the one CPP event and charging, on average, throughout the non-event time periods. Small sample sizes for PBI customers on a CPP rate preclude any quantitative assessment of dispatch behavior.

[13] Some rates default customers onto the CPP rate, but they can opt out.

FIGURE 3-43: AVERAGE HOURLY NET DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR CPP (NON-PBI)

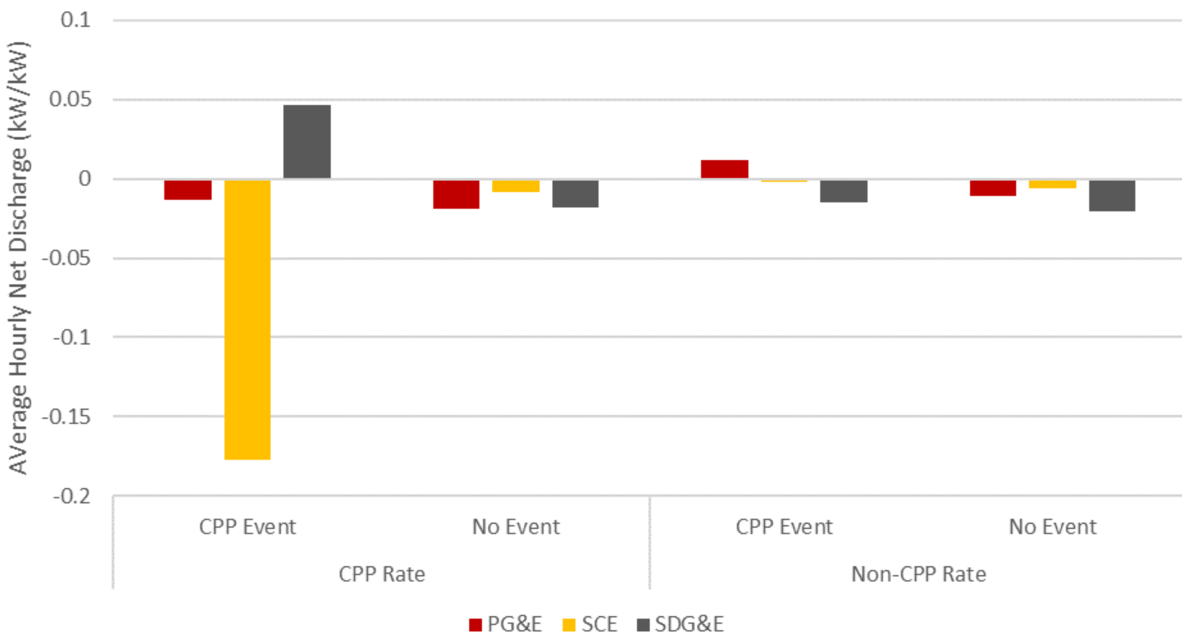
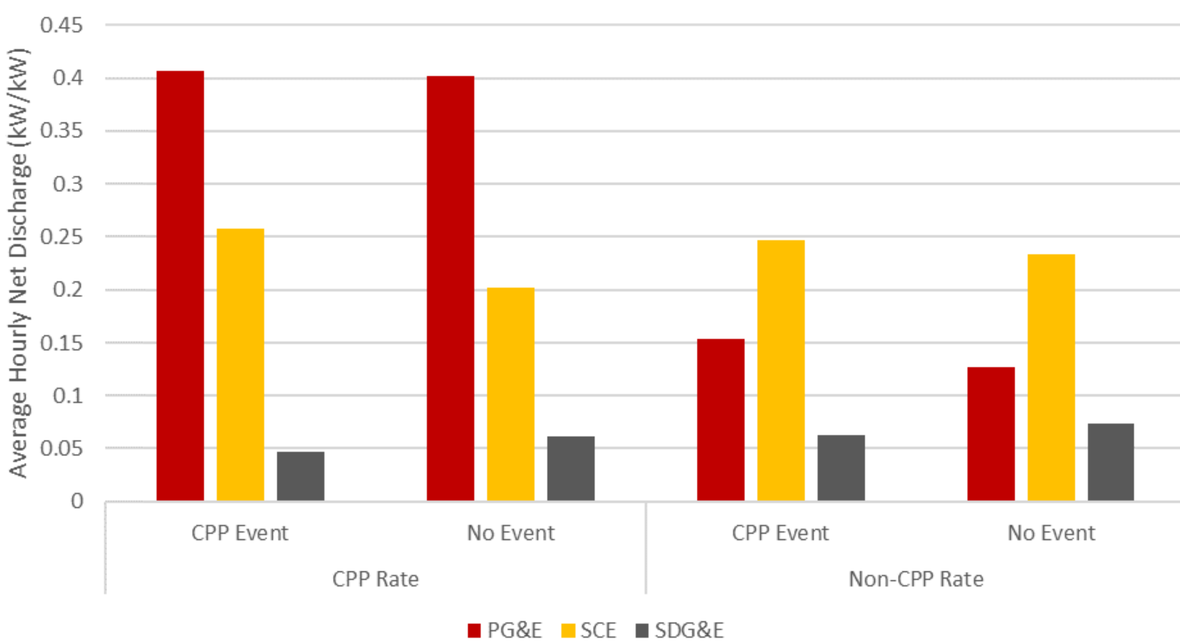


FIGURE 3-44: AVERAGE HOURLY NET DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR CPP (PBI)



Residential Projects

As discussed previously, we were unable to conduct a high rigor quantitative analysis on residential projects, but we did perform a qualitative assessment of the storage charge/discharge behavior. While there are still data quality issues with the projects in our sample, we've conducted a high-level assessment of how residential storage systems are being utilized throughout the day and year. Figure 3-45 conveys those findings. Overall, there is very little storage activity (and storage data) in the early part of the year. The bulk of the data and subsequent activity begins in July. These systems were generally paired with PV. During PV generation hours, the storage systems are both charging (red) and discharging (green). They are consistently charging overnight – from 8 pm through the early morning.

FIGURE 3-45: AVERAGE NET 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	0.007	0.007	0.011	0.042	0.046	0.012	-0.041	-0.096	-0.179	-0.066	-0.019	-0.020
1	0.007	0.007	0.011	0.042	0.042	0.009	-0.020	-0.049	-0.111	-0.056	-0.014	-0.014
2	0.007	0.007	0.012	0.044	0.038	0.008	0.002	-0.003	-0.019	-0.045	-0.008	-0.008
3	0.007	0.007	0.013	0.044	0.035	0.008	-0.001	-0.002	-0.007	-0.013	-0.001	-0.001
4	0.007	0.007	0.013	0.044	0.033	0.007	-0.006	-0.001	-0.001	0.001	0.002	0.002
5	0.007	0.007	0.002	0.003	0.000	-0.001	-0.008	-0.001	0.000	0.002	0.002	0.002
6	0.007	0.006	0.001	-0.004	-0.010	-0.012	-0.010	-0.002	-0.001	0.000	0.001	0.002
7	0.004	-0.009	-0.009	-0.032	-0.035	-0.053	-0.018	-0.006	-0.006	-0.010	-0.005	0.000
8	-0.021	-0.077	-0.032	-0.078	-0.075	-0.062	-0.024	-0.012	-0.013	-0.021	-0.018	-0.014
9	-0.059	-0.088	-0.042	-0.107	-0.107	-0.019	-0.007	-0.002	-0.003	-0.008	-0.009	-0.014
10	-0.048	-0.003	-0.039	-0.113	-0.125	-0.016	-0.004	-0.002	0.000	-0.006	-0.004	-0.005
11	-0.025	0.007	-0.025	-0.102	-0.134	-0.015	0.087	0.200	0.378	0.172	0.141	0.141
12	-0.010	0.007	-0.011	-0.062	-0.103	-0.015	0.083	0.181	0.357	0.155	0.142	0.147
13	0.000	0.003	-0.003	-0.024	-0.041	-0.007	-0.060	-0.237	-0.425	-0.123	0.067	0.081
14	-0.002	0.001	-0.001	-0.012	-0.008	0.009	0.151	0.205	0.371	0.067	0.124	0.133
15	0.002	0.002	0.001	-0.007	-0.003	0.004	-0.048	-0.214	-0.346	-0.002	0.068	0.075
16	0.006	0.000	0.000	-0.002	-0.001	-0.004	0.151	0.253	0.396	-0.035	-0.066	-0.063
17	0.007	0.009	0.001	0.001	0.001	-0.003	-0.057	-0.105	-0.117	0.091	-0.051	-0.058
18	0.007	0.007	0.002	0.005	0.005	0.003	0.012	0.101	0.144	0.017	-0.060	-0.062
19	0.007	0.007	0.017	0.058	0.076	0.011	0.043	0.154	0.218	0.047	-0.058	-0.067
20	0.007	0.007	0.015	0.058	0.106	0.012	-0.077	-0.104	-0.179	-0.067	-0.078	-0.085
21	0.007	0.007	0.015	0.055	0.099	0.012	-0.083	-0.108	-0.186	-0.067	-0.074	-0.083
22	0.007	0.007	0.013	0.052	0.077	0.011	-0.059	-0.107	-0.184	-0.067	-0.079	-0.083
23	0.007	0.007	0.011	0.046	0.056	0.010	-0.054	-0.105	-0.176	-0.058	-0.047	-0.054

3.6 SYSTEM IMPACTS

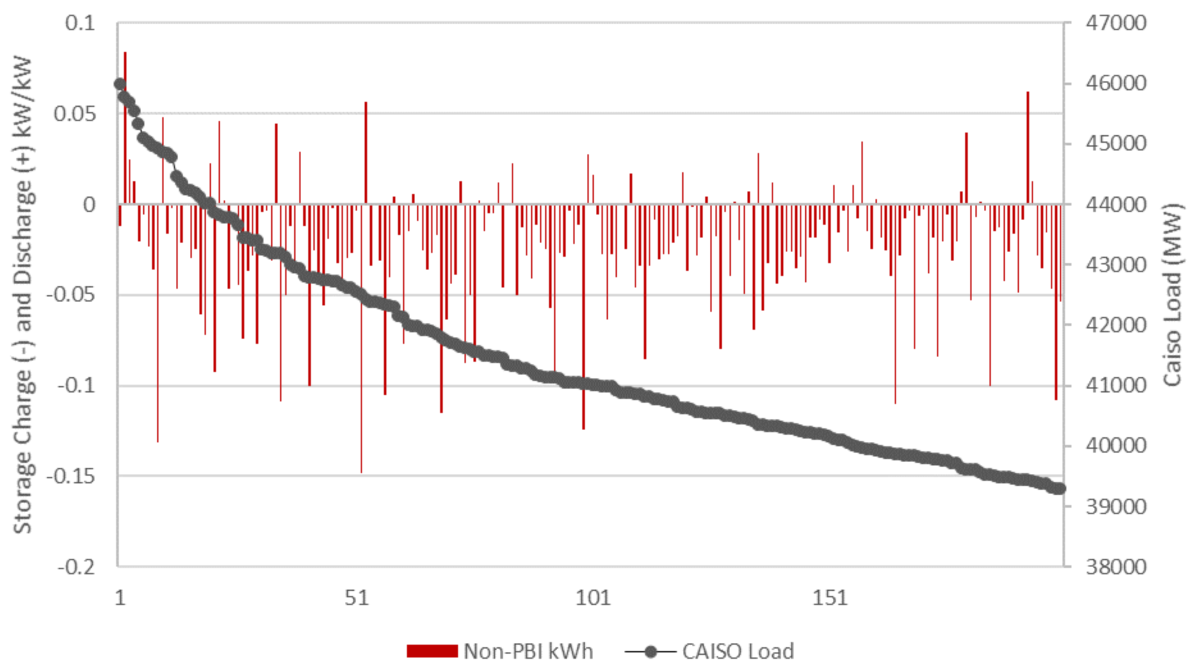
Non-residential Projects

Another key component of the analysis of AES systems is the impact projects have on the electricity grid. Storage discharge behavior that is coincident to utility or CAISO system peak demand can provide additional benefits beyond customer-specific ones. These benefits include avoided generation capacity costs and transmission and distribution costs.

We evaluated this potential benefit by quantifying the storage dispatch from our sample of non-residential projects and comparing that to the top 200 peak demand hours throughout 2016 for both the CAISO system[14] as well as the three IOUs. Given the significant differences that have been observed between non-PBI and PBI projects, we analyzed PBI and non-PBI projects separately. It's important to note that storage project operators are generally not aware of system or utility level peak hours unless they are enrolled in a demand response program or CPP tariffs, where a price signal is generated to shift or reduce demand. Customers understand their facility operations and bill rate structure, but grid level demand is generally not in their purview.

Figure 3-46 below presents the average kW discharge per rebated capacity for non-PBI projects along with the peak MW for each of the top 200 CAISO hours. Non-PBI projects were charging during 165 of the top 200 hours and therefore increasing coincident peak demand during those hours.

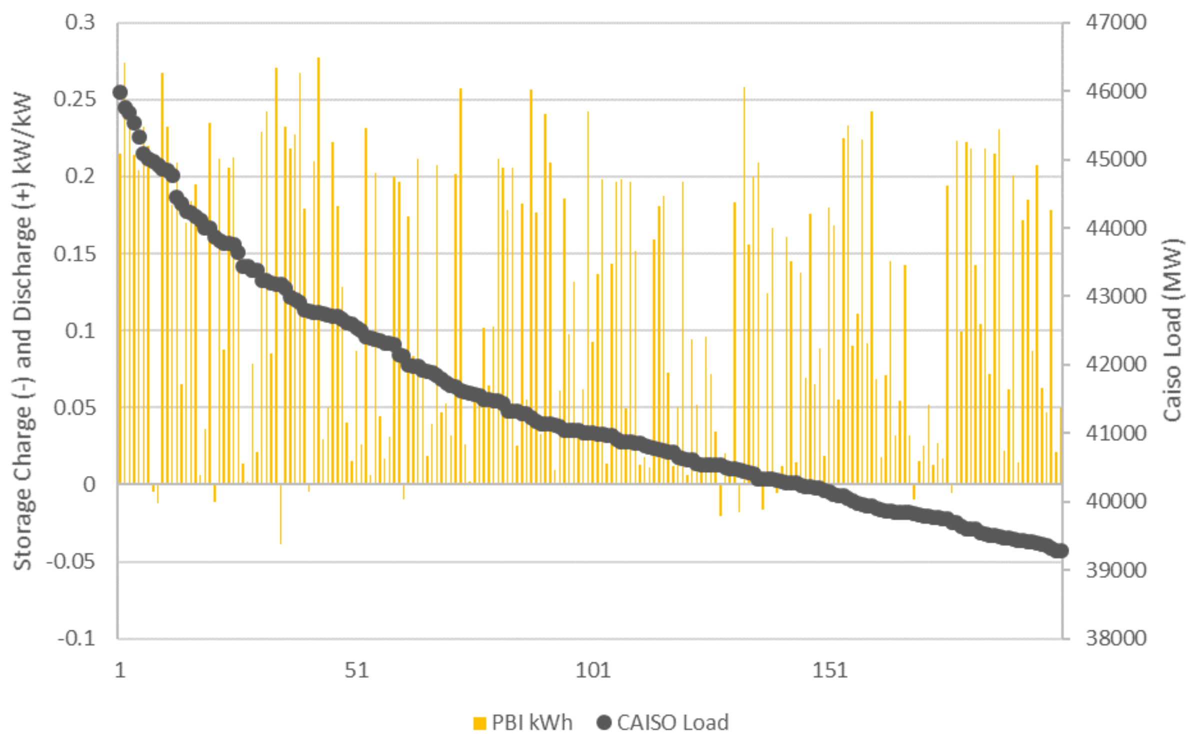
FIGURE 3-46: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS FOR NON-PBI PROJECTS



14 The top 200 CAISO peak hours all fall within June and September, beginning on 6/3 and ending on 9/27. The top CAISO load hour was on 7/27 at 3 pm (PST). The top 10 hours all occurred within 7/27 and 7/30.

Figure 3-47 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 188 of the top 200 CAISO peak hours and therefore contributing to coincident peak demand reduction.

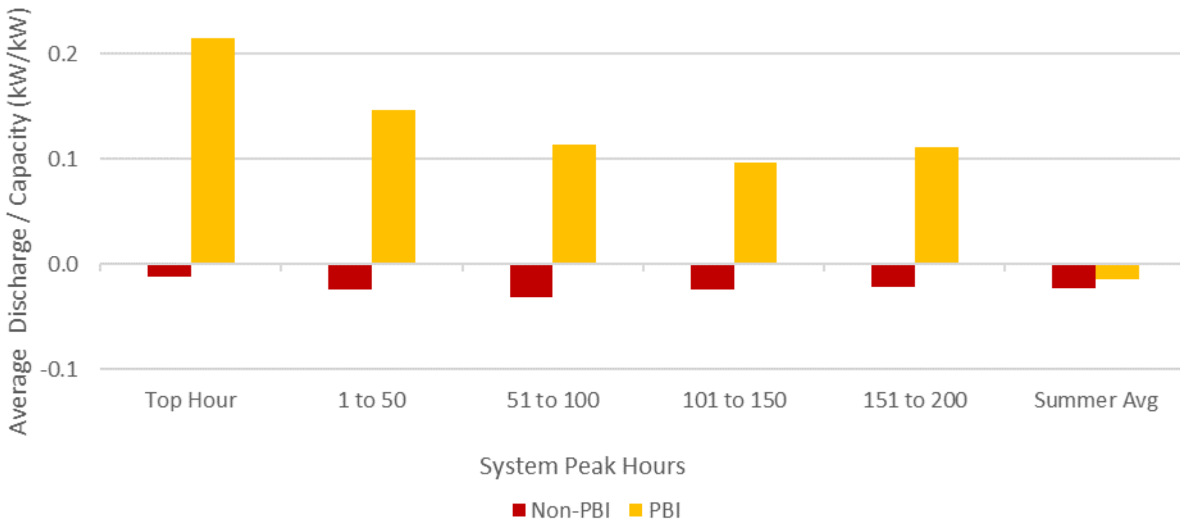
FIGURE 3-47: AVERAGE HOURLY NET DISCHARGE KW PER KW DURING CAISO TOP 200 HOURS FOR PBI PROJECTS



We also examined how the average net discharge throughout the top 200 system peak hours (2016) compared to the average over the course of the summer. All 200 system peak hours occurred within June and September (inclusive) so we have defined summer within that range.[15] Figure 3-48 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 0.222 kW (per kW rebated capacity) during the CAISO peak hour. Non-PBI projects, however, are charging roughly 0.01 kW (per kW rebated capacity) during that hour. A similar trend is evident across the other bins. Given that storage projects charge more than they discharge over time, the summer average for both project types is net charging.

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

FIGURE 3-48: NET DISCHARGE KWH PER REBATED CAPACITY KW DURING CAISO PEAK HOURS FOR ALL PROJECTS WITH SUMMER AVERAGE



We also examined the net discharge behavior of storage systems for the peak load hours for the three IOUs. The results for PBI and non-PBI projects are presented in Figure 3-49 and Figure 3-50, 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 peak demand reduction. They are smaller systems that exhibit a "snap-back" effect where discharge events are immediately followed by a charge event. Larger storage systems exhibit discharge behavior, often followed by an idle period. Charging does not occur until later in the evening or overnight.

FIGURE 3-49: NET DISCHARGE KWH PER REBATED CAPACITY KW DURING SYSTEM PEAK HOURS FOR PBI PROJECTS

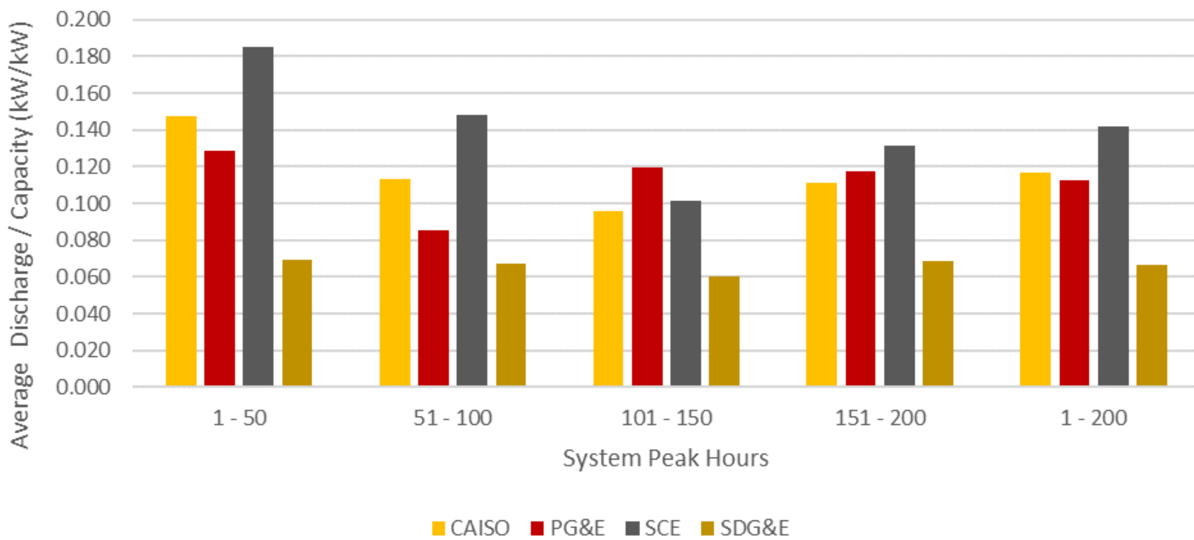
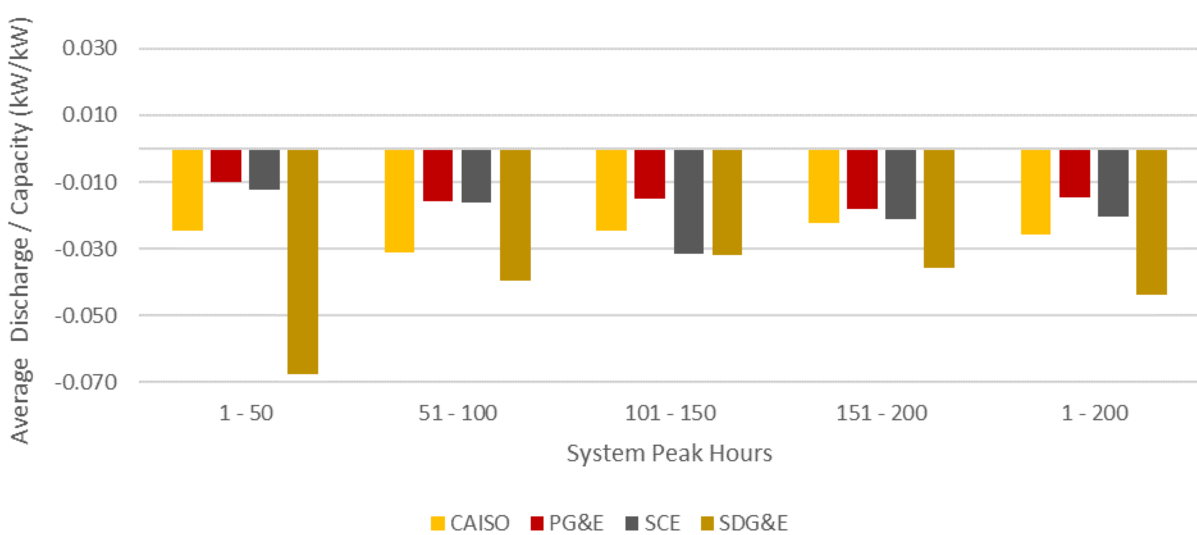


FIGURE 3-50: NET DISCHARGE KWH PER REBATED CAPACITY KW DURING SYSTEM PEAK HOURS FOR NON-PBI PROJECTS



We also assessed discharge behavior for customers enrolled in demand response (DR) programs. We received specific day ahead and real time award information from one of the IOUs. We merged those events onto our analysis dataset to identify whether the battery was 1) discharging if they participated in a supply side DR event or 2) absorbing load from the grid if the customer participated in an excess supply

DR event. Table 3-2 presents those results by project type. There were a total of 22 event hours between PBI and non-PBI projects which resulted in net discharging of roughly 13,700 kWh. The project that participated in the excess supply side program absorbed roughly 4,500 kWh during the 6 event hours.

TABLE 3-2: DEMAND RESPONSE EVENTS AND TOTAL NET DISCHARGE/CHARGE

Project Type	Demand Response Event	n Hours Awarded	Total Rebated Capacity kW	Net Discharge/Charge kWh during Events
PBI	Supply Side	18	882	13,602
	Excess Supply Side	6	90	-4,475
Non-PBI	Supply Side	4	81	68

We also received information on which projects participated in another DR auction, but we were unable to ascertain the exact timing of the events and whether they were awarded. Thirty non-PBI projects and two PBI projects participated in that program.

Residential Projects

Data quality issues limited the extent of analysis for residential projects. We did not perform an assessment of system level impacts from residential storage. Given the total rebated capacity of residential projects (4% of the total SGIP rebated capacity), the impacts of residential projects would be very small relative to the non-residential impacts.

3.7 GREENHOUSE GAS IMPACTS

Non-Residential Projects

This section summarizes the impact estimates of GHG for SGIP rebated AES projects. The GHG considered in this analysis is carbon dioxide (CO_2), as this is the primary pollutant that is potentially affected by the operation of SGIP AES projects.

Fifteen-minute GHG impacts were calculated for each SGIP project as the difference between the grid power plant GHG emissions for actual SGIP AES operations 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. Facility loads are identical for Baseline and SGIP conditions. What varies is the timing and quantity of grid power plant electricity required to maintain balance between facility loads and electrical supply in response to AES charging and discharging.

AES technologies are not perfectly efficient. Consequently, the amount of energy they discharge over any given period is always less than the amount of energy required to charge the system. In other words, over the course of a year, AES technologies will increase the energy consumption of a customer's home or facility relative to the baseline condition without the AES.

The 15-minute energy (MWh) impact of each standalone SGIP AES project is equal to the charge or discharge that occurred during that interval. The energy impact during each 15-minute interval is then multiplied by the marginal emission rate for that interval (Metric Tons CO_2 / MWh) to arrive at a 15-minute GHG emissions rate. GHG emissions generally increase during AES charge and decrease during AES discharge. The project's annual GHG impact is the sum of the hourly GHG emissions.

For AES projects to reduce GHG emissions, the GHGs "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.

It's important to note that system operators are generally not aware of when marginal GHG emissions 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.

Figure 3-51 and Figure 3-52 convey the results of that analysis for non-PBI and PBI projects, respectively. Storage dispatch behavior led to an increase in GHG emissions for 176 of 181 non-PBI projects and 66 of 78 PBI projects. Additional details on the GHG impact methodology and the assumptions made in developing a marginal GHG emissions dataset are included in Appendix A.

FIGURE 3-51: NET CO2 EMISSIONS PER REBATED CAPACITY FOR NON-PBI PROJECTS

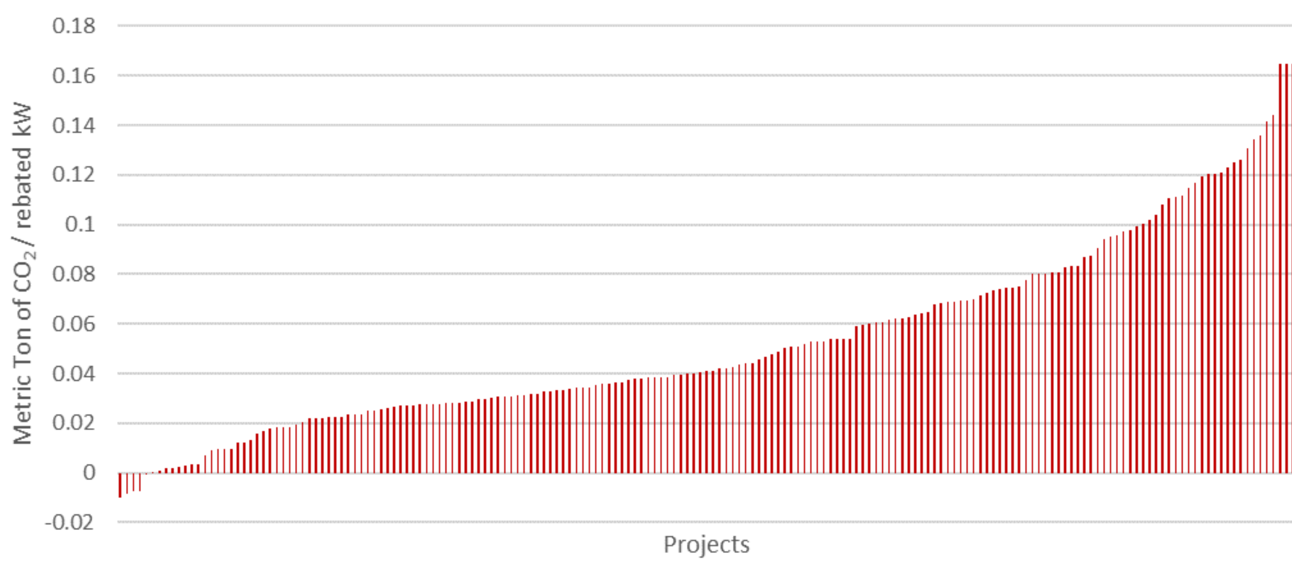


FIGURE 3-52: NET CO2 EMISSIONS PER REBATED CAPACITY FOR PBI PROJECTS

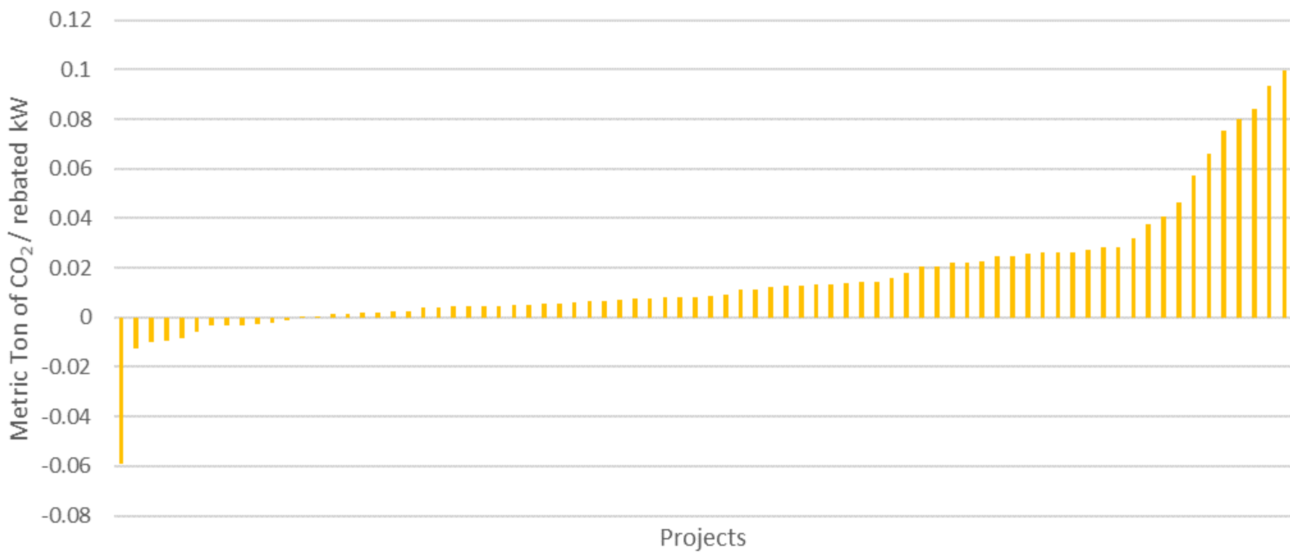


Figure 3-53 shows that, on average, both PBI and non-PBI projects are increasing emissions due to a combination of losses due to inefficiencies and less than ideal operation timing. The magnitude of normalized emissions for non-PBI projects is more significant overall.

FIGURE 3-53: CO2 EMISSIONS PER REBATED CAPACITY

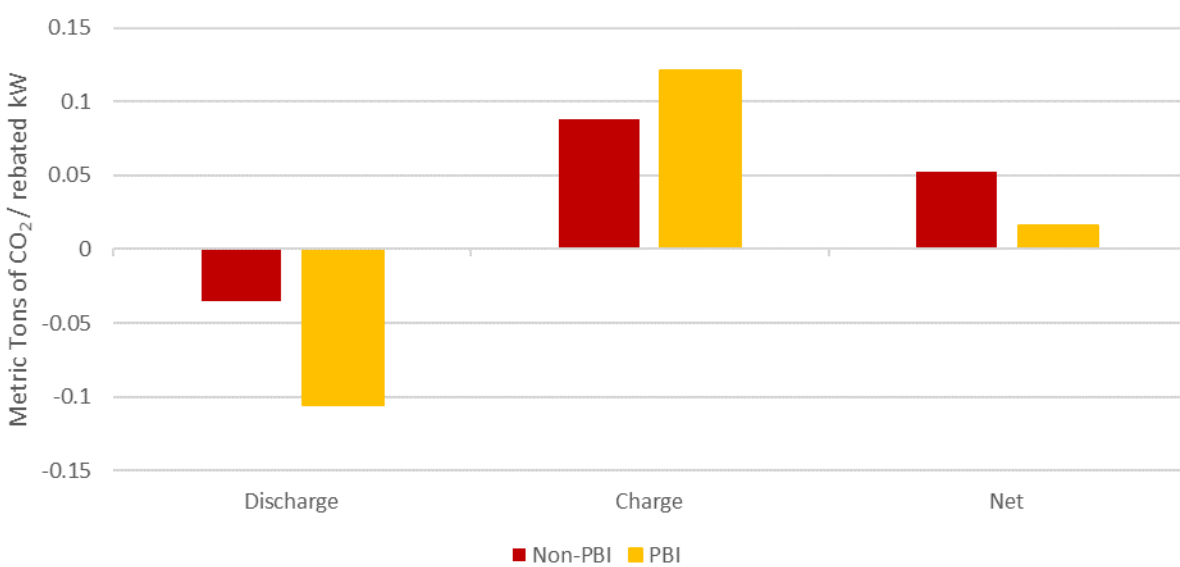
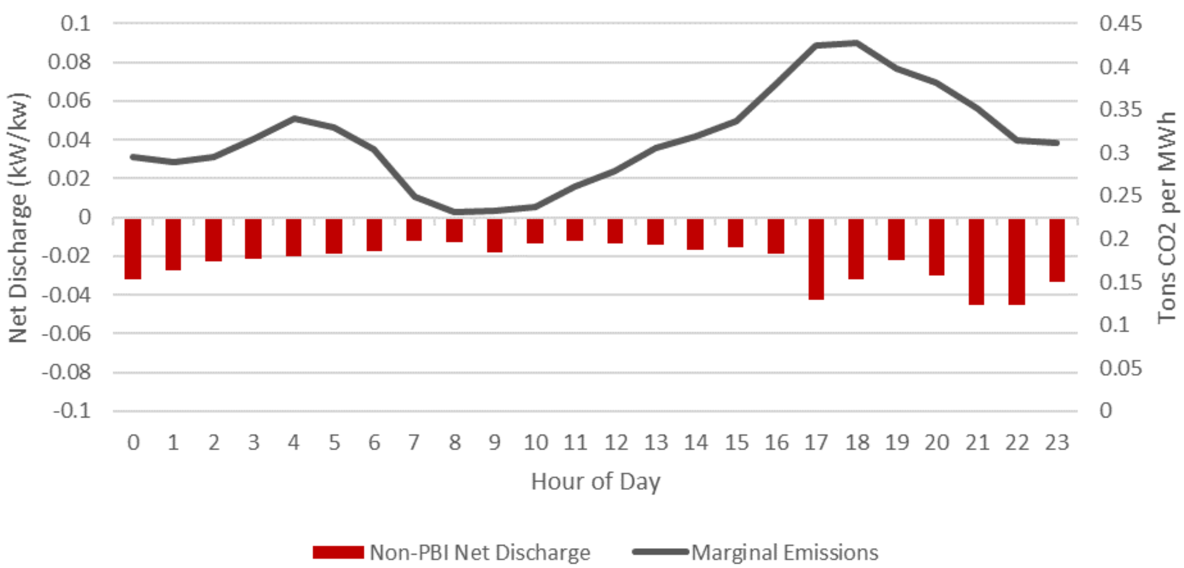


Figure 3-55 through Figure 3-59 display the average daily net discharge for both project types (and combined) for the summer and winter periods along with the marginal emissions rate. Non-PBI projects, on average, are charging across all hours which intuitively leads to an increase in emissions.

FIGURE 3-54: NON-PBI NET DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR SUMMER



PBI projects are discharging hourly throughout periods when marginal emissions are high. That benefit, however, is being negated by charge events that also occur during times of moderate to high marginal emissions.

FIGURE 3-55: PBI NET DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR SUMMER

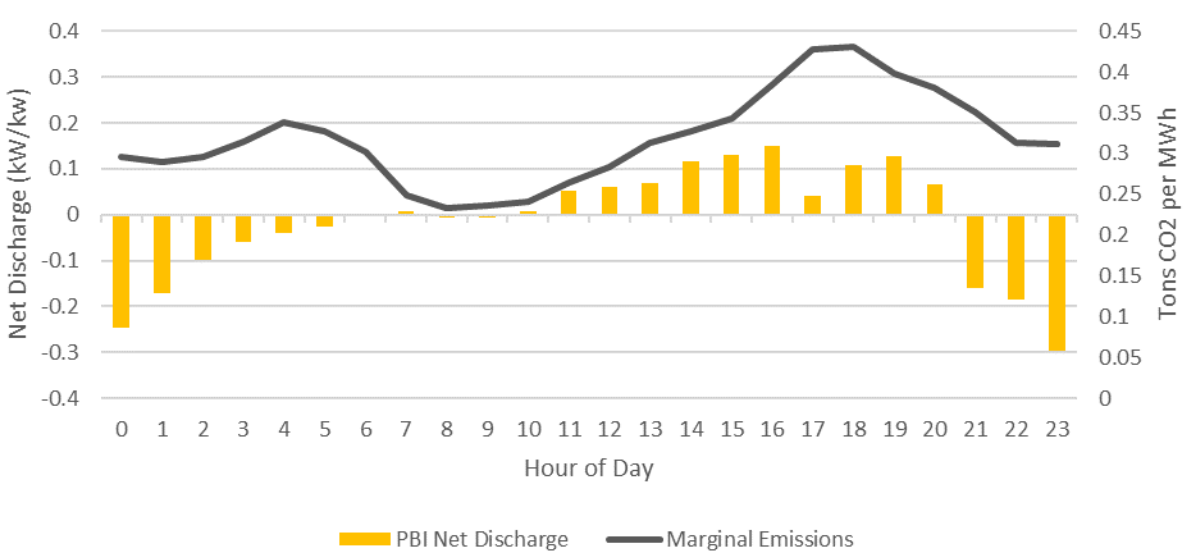


FIGURE 3-56: NON-PBI NET DISCHARGE PER REBATED KW MARGINAL EMISSIONS RATE FOR WINTER

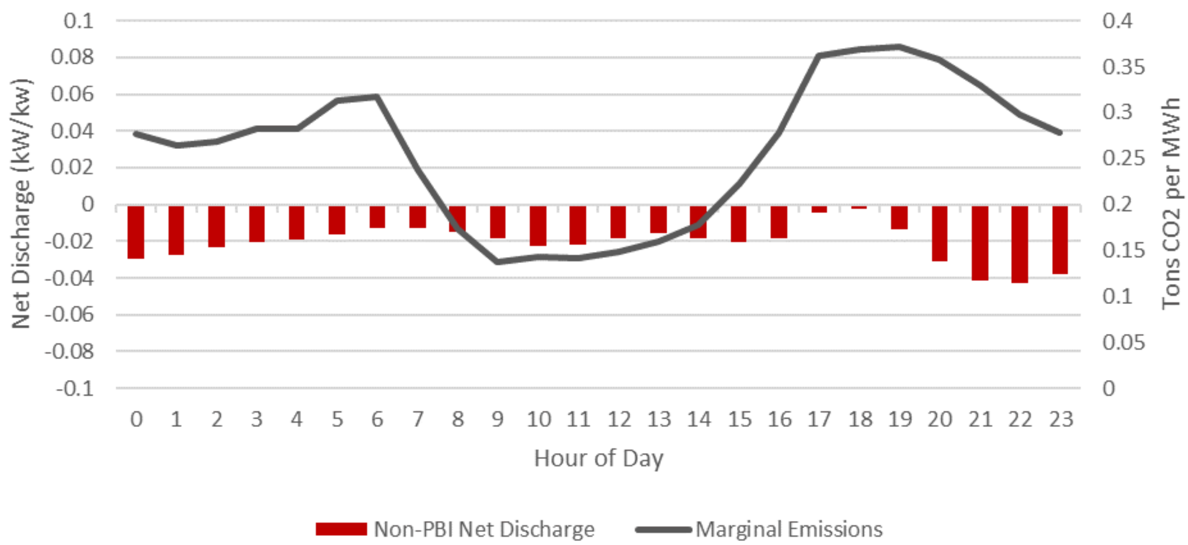


FIGURE 3-57: PBI NET KWH DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR WINTER

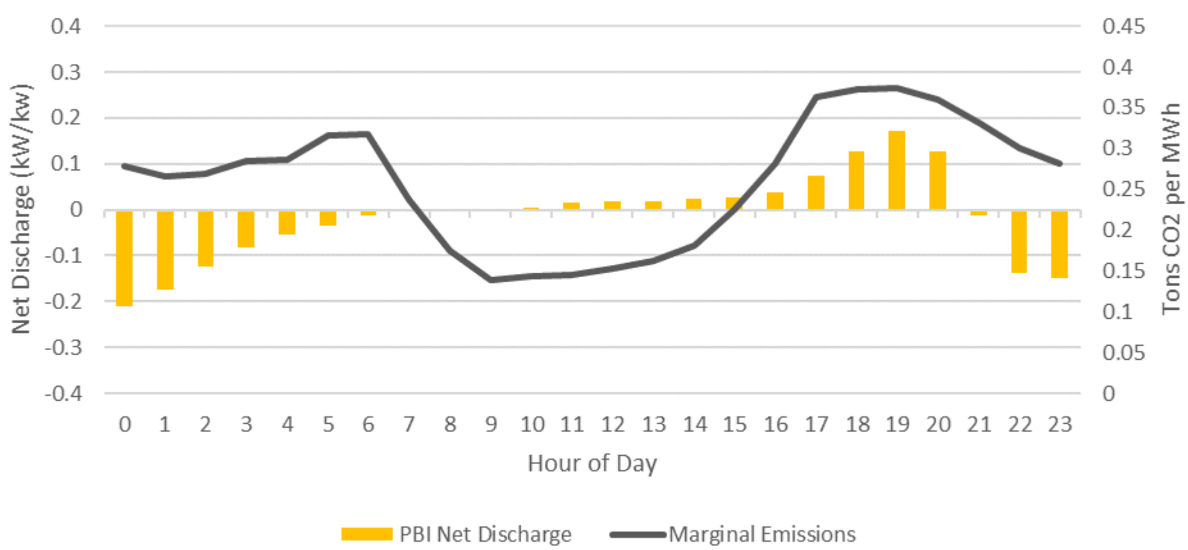


FIGURE 3-58: ALL PROJECTS NET KWH DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR SUMMER

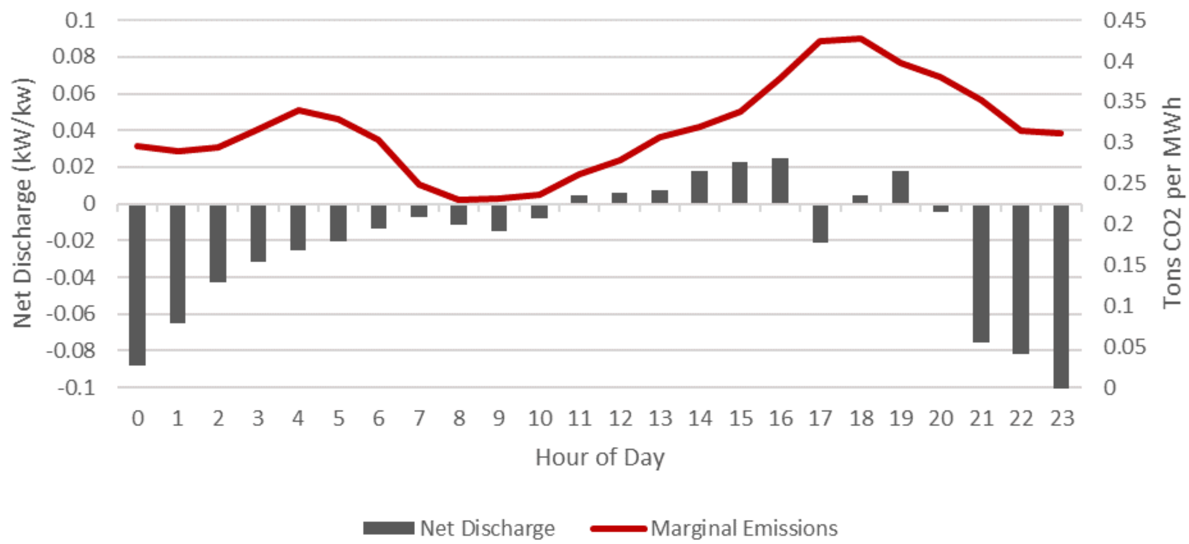
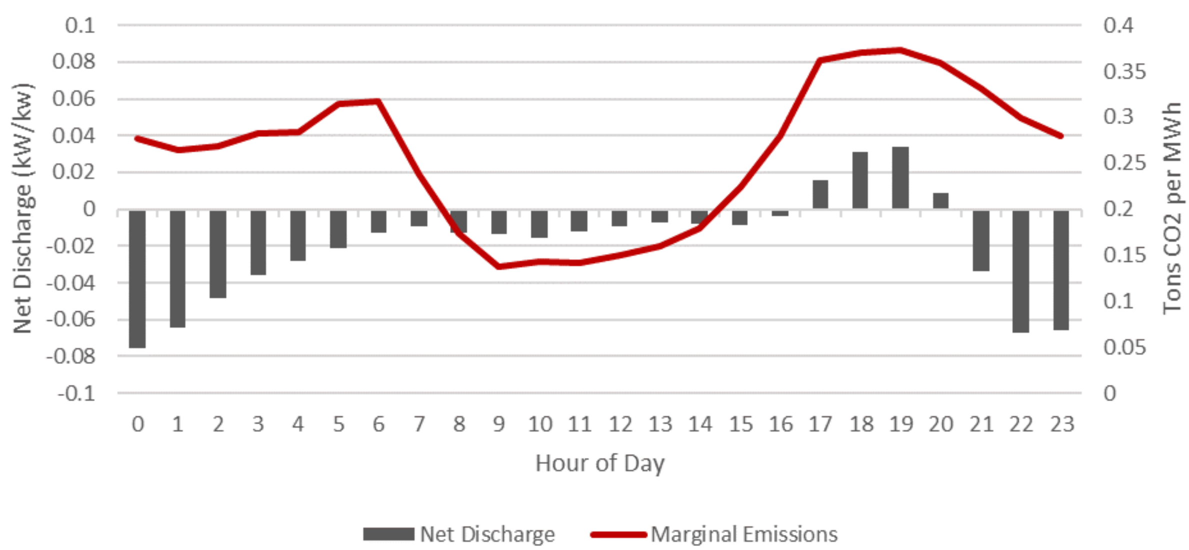
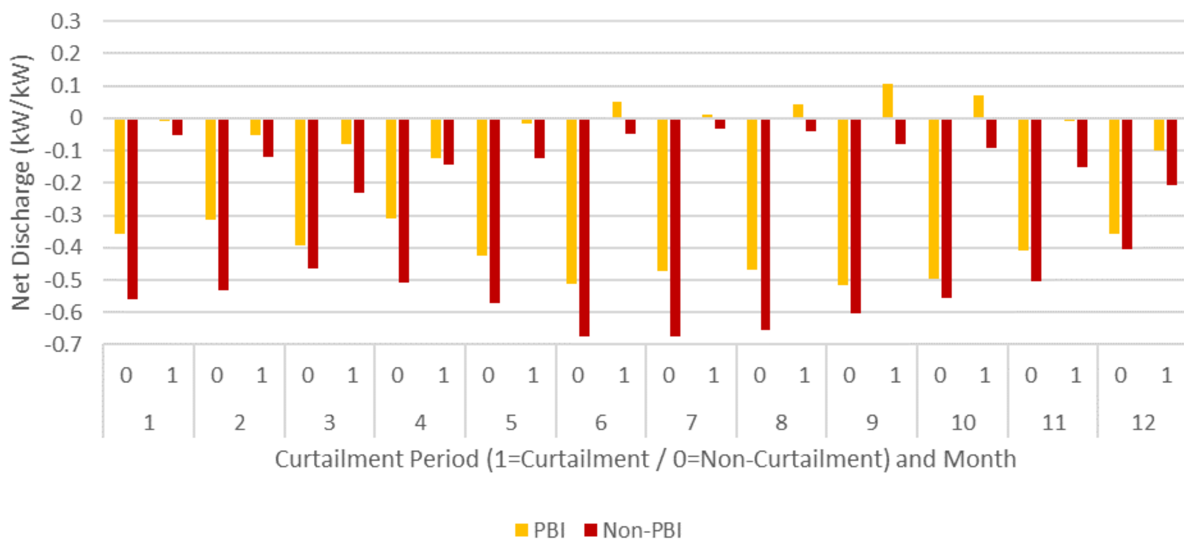


FIGURE 3-59: ALL PROJECTS NET KWH DISCHARGE PER REBATED KW AND MARGINAL EMISSIONS RATE FOR WINTER



Another important component of storage impacts on greenhouse gas emissions is the 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." 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 (kW). On average, both PBI and non-PBI customers are charging less during curtailment hours relative to non-curtailment hours during any given month. Between June and October, PBI systems are discharging during curtailment hours. This discharge may be providing customer benefits but is counter-productive from a GHG reduction perspective.

FIGURE 3-60: NET DISCHARGE KW PER KW BY MONTH AND CURTAILMENT EVENTS



Residential Projects

Data quality issues limited the extent of analysis for residential projects. We did not perform an assessment of GHG impacts from residential storage.

3.8 UTILITY MARGINAL COST IMPACTS

Non-residential Projects

Utility marginal cost impacts were calculated for each IOU and each 15-minute time increment in 2016. The utility marginal costs used in our analysis are based on the E3 Distributed Energy Resource (DER) Avoided Cost Calculator[16]. The DER Avoided Cost Calculator was most recently updated and adopted by

[16] A more detailed description of the calculator can be found in Section 4.

CPUC Resolution E-4801 in September 2016.[17,18] Storage system charging results in an increased load and therefore will 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[19] (RPS), and ancillary services ($/kWh) costs. Additional details on the marginal cost methodology and the assumptions made in developing a marginal cost dataset are included in Section 4. It is important to note that system operators are generally not aware of the cost of generating, transporting, and supplying energy.

The normalized utility marginal costs are shown in Figure 3-61 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 $0.50 per rebated capacity (kW) and the average marginal cost (-) for non-PBI projects is $8.10 per rebated capacity (kW).

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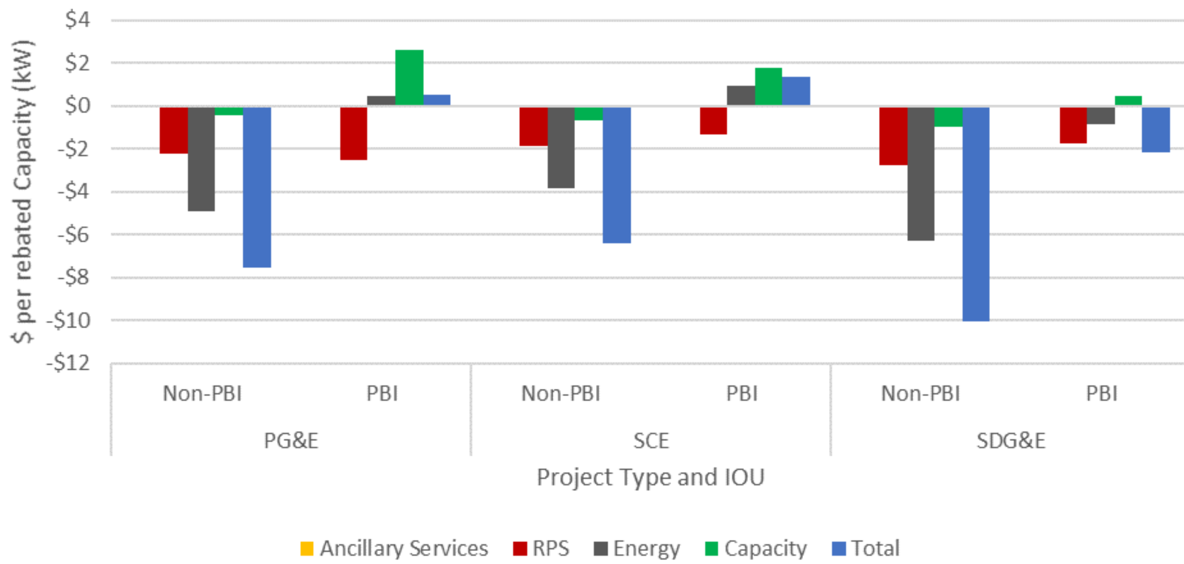
17 CPUC Resolution E-4801 is available at: http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&DocID=167779209

18 2016 DER Avoided Cost Calculator and Documentation available at: https://www.ethree.com/public_proceedings/distributed-energy-resources-der-avoided-cost-proceedings/

19 Section 4 provided a detailed definition of RPS and all other marginal costs

FIGURE 3-61: MARGINAL COST $ PER REBATED CAPACITY (KW) BY IOU AND PROJECT TYPE



Overall, non-PBI projects represent a net cost to the utility system per rebated capacity. The marginal costs modeled in this study are highest when energy prices are high and the CAISO system load is peaking. Section 3.5 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 3.6 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 3-61). 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.

Residential Projects

Data quality issues limited the extent of analysis for residential projects. We did not perform an assessment of utility marginal cost impacts for residential storage projects.

3.9 STORAGE CO-LOCATED WITH PV IMPACTS

Another assessment we conducted was examining storage behavior for projects co-located with PV. We determined (based on a review of IOU load data) that eight of 181 non-PBI projects and 29 of 78 PBI projects were co-located with behind-the-meter PV generation at some point during 2016. An assessment was conducted to convey:

- How storage behavior looks during PV generation hours
- The timing of charge/discharge throughout the day that may help or hinder the “duck curve” effect

We examined the timing of aggregated storage dispatch for PBI projects co-located with PV and PBI projects without PV to better understand if the storage systems are operating differently throughout the year. We performed this analysis by taking the average kW discharge (normalized by rebated kW capacity) for each month and hour within the year. Figure 3-62 and Figure 3-63 present those findings. Discharging is positive and is shown in green and charging is negative and is shown in red. There is little difference in the pattern and timing of storage discharging for sites with PV compared to those without PV. PBI projects tend to discharge energy during PV generation hours rather than charge.

FIGURE 3-62: AVERAGE NET DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI PROJECTS WITH NO PV

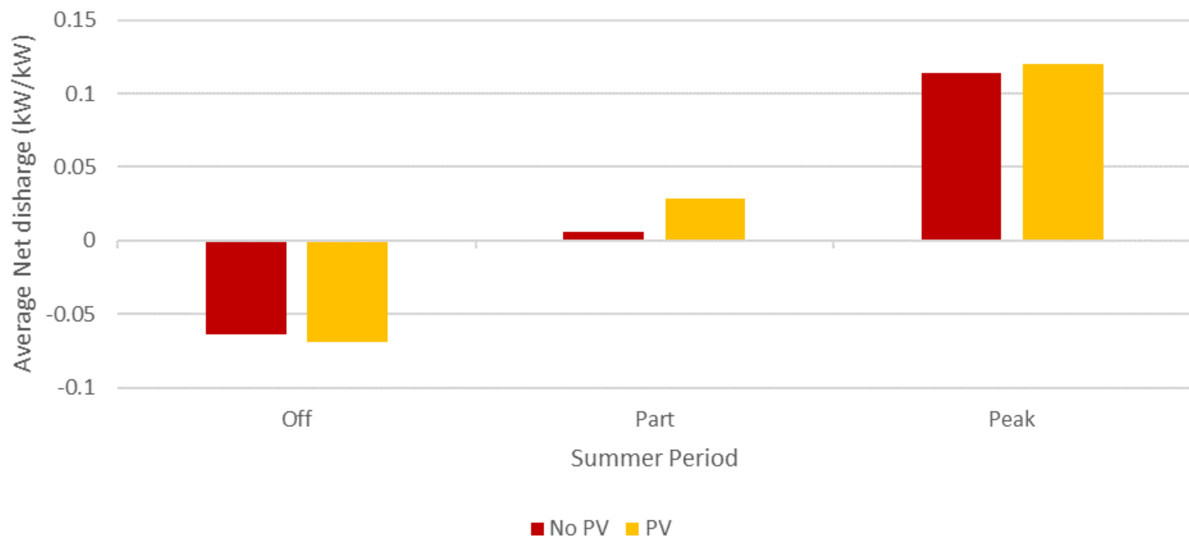
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	-0.151	-0.170	-0.177	-0.189	-0.190	-0.254	-0.242	-0.248	-0.245	-0.227	-0.241	-0.263
1	-0.130	-0.134	-0.139	-0.143	-0.127	-0.180	-0.181	-0.175	-0.172	-0.138	-0.205	-0.211
2	-0.088	-0.092	-0.100	-0.102	-0.106	-0.108	-0.105	-0.090	-0.086	-0.081	-0.137	-0.135
3	-0.059	-0.053	-0.067	-0.066	-0.075	-0.068	-0.063	-0.046	-0.041	-0.046	-0.086	-0.087
4	-0.051	-0.035	-0.047	-0.040	-0.050	-0.042	-0.040	-0.023	-0.019	-0.025	-0.043	-0.055
5	-0.034	-0.019	-0.028	-0.025	-0.030	-0.027	-0.021	-0.017	-0.011	-0.018	-0.024	-0.033
6	-0.009	0.011	0.007	0.012	0.007	0.008	0.003	0.013	0.014	0.012	0.007	0.005
7	0.008	0.045	0.036	0.027	0.019	0.011	0.013	0.022	0.012	0.013	0.013	0.005
8	0.012	-0.026	-0.022	0.001	-0.005	-0.006	-0.007	-0.010	-0.009	-0.009	0.000	-0.004
9	0.015	-0.003	-0.027	0.006	-0.015	-0.007	-0.008	-0.016	-0.013	-0.008	0.013	0.004
10	0.006	0.026	-0.008	0.022	0.011	0.004	0.010	0.009	0.002	0.007	0.028	0.012
11	-0.008	0.020	0.003	0.032	0.055	0.068	0.050	0.047	0.055	0.052	0.039	0.031
12	0.017	0.011	0.003	0.026	0.064	0.071	0.065	0.061	0.062	0.062	0.032	0.023
13	0.017	-0.002	-0.002	0.020	0.065	0.067	0.072	0.067	0.081	0.068	0.022	0.023
14	-0.007	-0.001	-0.009	0.004	0.082	0.139	0.113	0.136	0.129	0.095	0.031	0.023
15	-0.011	-0.006	-0.009	0.000	0.097	0.155	0.133	0.154	0.140	0.090	0.030	0.030
16	-0.016	-0.005	0.009	0.019	0.110	0.154	0.153	0.171	0.146	0.106	0.043	0.036
17	0.019	0.013	0.055	0.077	0.043	0.026	0.034	0.020	0.018	0.076	0.074	0.065
18	0.052	0.042	0.123	0.142	0.076	0.067	0.076	0.070	0.074	0.136	0.105	0.097
19	0.121	0.122	0.155	0.189	0.116	0.107	0.100	0.091	0.099	0.127	0.144	0.160
20	0.128	0.157	0.125	0.082	0.045	0.064	0.050	0.038	0.044	0.025	0.121	0.160
21	-0.016	0.005	-0.033	-0.117	-0.119	-0.109	-0.111	-0.112	-0.118	-0.179	0.009	0.055
22	-0.146	-0.183	-0.111	-0.140	-0.164	-0.206	-0.173	-0.203	-0.195	-0.170	-0.180	-0.212
23	-0.049	-0.086	-0.150	-0.236	-0.267	-0.317	-0.296	-0.304	-0.289	-0.272	-0.160	-0.158

FIGURE 3-63: AVERAGE NET DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI PROJECTS WITH PV

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	-0.216	-0.185	-0.225	-0.202	-0.258	-0.292	-0.299	-0.285	-0.267	-0.252	-0.262	-0.220
1	-0.194	-0.162	-0.174	-0.152	-0.193	-0.194	-0.209	-0.214	-0.200	-0.181	-0.240	-0.208
2	-0.136	-0.118	-0.114	-0.103	-0.132	-0.127	-0.101	-0.113	-0.131	-0.121	-0.185	-0.178
3	-0.067	-0.074	-0.071	-0.072	-0.093	-0.080	-0.064	-0.056	-0.083	-0.085	-0.133	-0.156
4	-0.050	-0.053	-0.058	-0.054	-0.067	-0.059	-0.049	-0.039	-0.049	-0.056	-0.096	-0.106
5	-0.037	-0.035	-0.046	-0.042	-0.044	-0.042	-0.038	-0.031	-0.026	-0.033	-0.067	-0.075
6	-0.028	-0.021	-0.032	-0.037	-0.031	-0.025	-0.027	-0.020	-0.019	-0.022	-0.035	-0.043
7	-0.018	-0.018	-0.015	-0.015	-0.007	-0.006	-0.006	-0.005	-0.004	0.001	-0.016	-0.020
8	-0.005	-0.007	-0.006	-0.004	0.002	0.001	0.000	-0.007	0.001	0.000	-0.001	-0.002
9	-0.001	-0.012	-0.008	-0.006	0.004	0.011	0.002	-0.002	0.002	-0.001	0.009	0.008
10	-0.002	-0.017	-0.005	-0.015	0.004	0.011	0.011	0.005	0.005	-0.001	0.000	0.006
11	-0.003	-0.014	0.001	0.008	0.041	0.054	0.054	0.049	0.044	0.032	0.009	0.010
12	0.002	0.000	0.013	0.012	0.045	0.062	0.063	0.067	0.054	0.040	0.015	0.006
13	0.009	0.006	0.017	0.015	0.052	0.073	0.072	0.093	0.059	0.047	0.022	0.006
14	0.019	0.017	0.020	0.033	0.101	0.139	0.136	0.151	0.091	0.043	0.034	0.016
15	0.038	0.028	0.034	0.030	0.115	0.151	0.146	0.177	0.103	0.056	0.048	0.030
16	0.048	0.046	0.046	0.049	0.138	0.182	0.177	0.198	0.115	0.083	0.057	0.048
17	0.059	0.054	0.101	0.148	0.112	0.041	0.054	0.045	0.058	0.116	0.080	0.075
18	0.100	0.088	0.185	0.246	0.198	0.152	0.155	0.132	0.188	0.245	0.155	0.126
19	0.140	0.144	0.211	0.253	0.231	0.170	0.167	0.150	0.216	0.263	0.230	0.195
20	0.133	0.151	0.125	0.085	0.084	0.106	0.098	0.077	0.124	0.122	0.226	0.224
21	0.051	0.051	-0.028	-0.098	-0.135	-0.108	-0.111	-0.097	-0.113	-0.142	0.059	0.089
22	-0.104	-0.104	-0.126	-0.124	-0.162	-0.202	-0.189	-0.208	-0.168	-0.143	-0.132	-0.114
23	-0.040	-0.084	-0.187	-0.235	-0.283	-0.335	-0.330	-0.330	-0.301	-0.300	-0.124	-0.042

Figure 3-64 summarizes the overall hourly kWh net discharge for sites with and without PV. Dispatch is almost identical for these projects in the off and peak periods. Sites that are co-located with PV discharge, on average, more than non-PV sites.

FIGURE 3-64: AVERAGE HOURLY NET KW DISCHARGE (PER REBATED KW) FOR PBI PROJECTS IN SUMMER PERIOD



We also reviewed the daily load shapes for projects that were co-located with PV and those without PV and plotted the CAISO load shape for that day. Figure 3-65 and Figure 3-66 present the average daily load with storage as well as the load absent storage along with the CAISO load for that day for each project type. This example represents the peak CAISO day in 2016. While the load shapes are clearly different during the daytime – given the PV generation during those hours – the storage dispatch behavior is almost identical.

FIGURE 3-65: AVERAGE LOAD PROFILE FOR PROJECTS WITH PV ON CAISO PEAK DAY

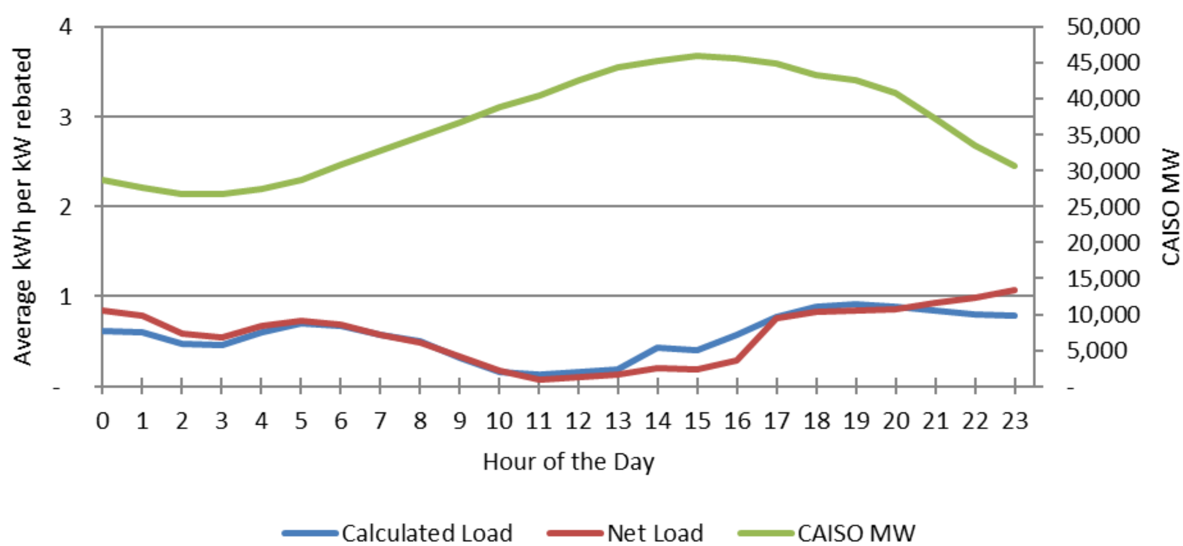


FIGURE 3-66: AVERAGE LOAD PROFILE FOR PROJECTS WITHOUT PV ON CAISO PEAK DAY

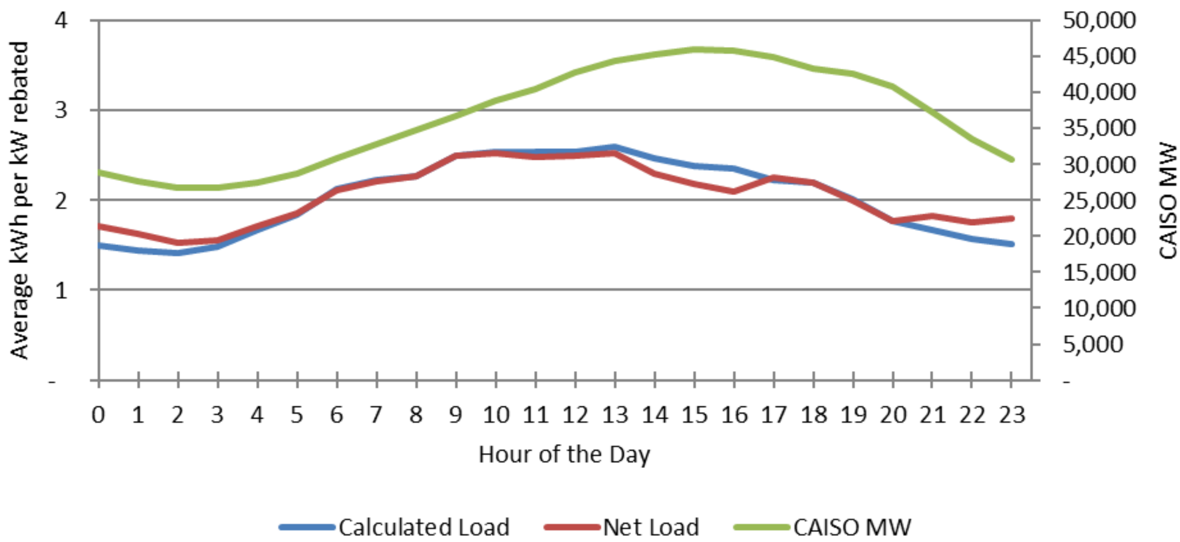


Figure 3-67 and Figure 3-68 present the average daily load with storage as well as the load absent storage along with the CAISO load for a different day for each project type. This example represents a Sunday in May in 2016 where "duck curve" effects might be more prominent. Again, the load shapes are clearly different, but the dispatch behavior is the same – discharging in the afternoon and charging overnight. On average, non-residential projects that are co-located with PV are not charging throughout the day when PV generation occurs.

FIGURE 3-67: AVERAGE LOAD PROFILE FOR PROJECTS WITH PV ON A MAY SUNDAY

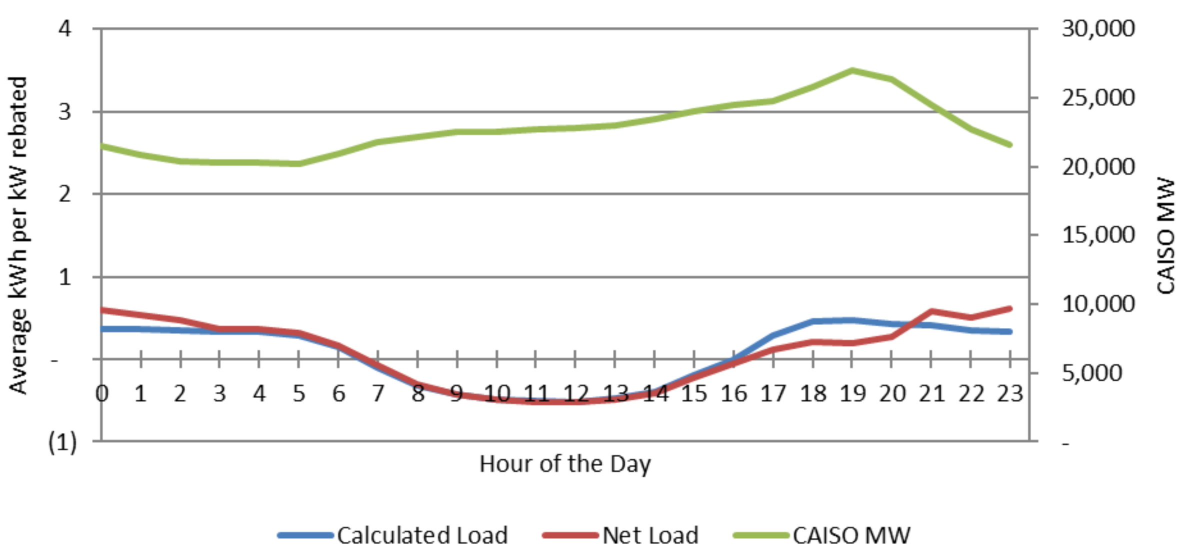
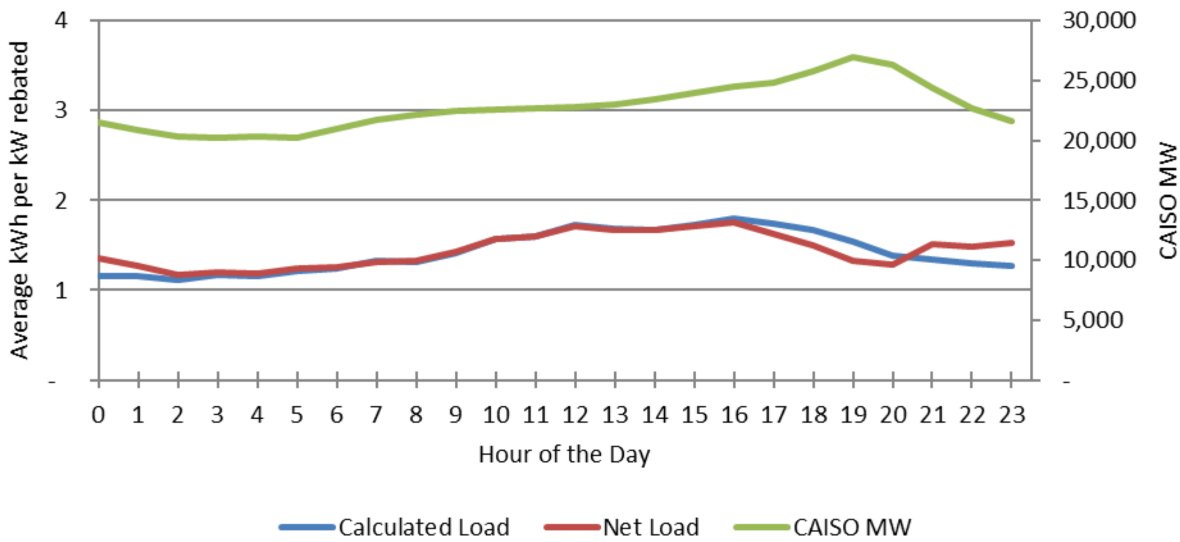


FIGURE 3-68: AVERAGE LOAD PROFILE FOR PROJECTS WITHOUT PV ON A MAY SUNDAY



3.10 POPULATION IMPACTS

Metered data available for the sample of projects were used to estimate population total impacts for 2016. This analysis was limited to non-residential projects from program year 2011 and later. Relative precision levels reported in the tables are based on a confidence level of 90%. Population estimates were calculated for the following 2016 impacts (details on the estimation methodology and relative precision calculation are included in Appendix B):

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

Customer peak demand impacts during summer months provide some indication of the way non-residential 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 3-3. PBI and non-PBI projects produced reductions in summertime average customer peak demand.

TABLE 3-3: POPULATION TOTAL SUMMER-TIME AVERAGE CUSTOMER PEAK DEMAND IMPACTS

Incentive	N	Population Impact (kW)	Relative Precision
PBI	69	-1,435	8%
Non-PBI	240	-484	8%
Total	**309**	**-1,919**	**6%**

CAISO system peak demand impacts are summarized in Table 3-4 (top hour). In 2016 the CAISO statewide system load peaked at 45,981 MW on July 27 during the hour from 4 to 5 PM PDT. While PBI projects delivered CAISO system peak demand reduction approaching 9 MW, non-PBI 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 (82%) reported for non-PBI is largely a consequence of the small population estimate of total impacts. That value is the denominator in the relative precision calculation; as it approaches zero, relative precision grows very large. The confidence interval for non-PBI population total CAISO system peak demand impacts is 12 to 126 kW.

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

Incentive	N	Population Impact (kW)	Relative Precision
PBI	69	-8,848	8%
Non-PBI	240	69	82%
Total	**309**	**-8,779**	**8%**

TABLE 3-5: CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 200 HOURS)

Incentive	N	Population Impact (Average kW)	Relative Precision
PBI	76	-5,544	3%
Non-PBI	242	127	11%
Total	**318**	**-5,416**	**3%**

Electric energy impacts (i.e., the total energy impact that resulted from charging and discharging AES projects) during 2016 are summarized in Table 3-6. Electric energy impacts for both PBI and non-PBI are positive, reflecting increased energy consumption, as expected. These impacts are for 2016; many projects were operating during the entirety of 2016, but others entered service mid-way through 2016. 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 4,672 MWh during 2016. This energy impact is approximately equivalent (but opposite in sign) to the energy impact of a 700 kW generator operating at an 80% capacity factor during 2016.

TABLE 3-6: ELECTRIC ENERGY IMPACTS

Incentive	N	Population Impact (MWh)	Relative Precision
PBI	83	3,692	2%
Non-PBI	246	980	5%
Total	**329**	**4,672**	**2%**

Greenhouse gas impacts during 2016 are summarized in Table 3-7. 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.

TABLE 3-7: GREENHOUSE GAS IMPACTS

Incentive	N	Population Impact (Metric tons CO_2)	Relative Precision
PBI	83	441	6%
Non-PBI	246	285	5%
Total	**329**	**726**	**4%**

Utility marginal cost impacts during 2016 are summarized in Table 3-8. Utility marginal costs are negative for PBI projects (costs were avoided) and positive for non-PBI projects (costs were incurred).

TABLE 3-8: UTILITY MARGINAL COST IMPACTS

Incentive	N	Population Impact (Avoided Cost $)	Relative Precision
PBI	83	($86,384)	10%
Non-PBI	246	$43,356	6%
Total	**329**	**($43,029)**	**21%**

4 IDEAL DISPATCH MODELING AND LONG-TERM IRP VALUE

This section describes analysis performed to quantify the potential grid level benefits of SGIP storage projects under optimal dispatch for different objectives. We employ two distinct approaches to quantify potential benefits of AES. The first is a short-term marginal cost approach using E3's DER Avoided Cost Model. In this approach, storage is dispatched based on one of three perspectives: In the customer perspective, storage is dispatched to minimize a customer's monthly electricity bill; in the utility perspective, storage is dispatched to minimize the marginal cost of serving load at the system level; in the carbon minimization perspective, storage is dispatched to minimize marginal carbon emissions for the associated customer. Each model run is executed with perfect load and price foresight, and optimizations are conducted on a monthly basis. The second is a long-term integrated resource planning approach with E3's Renewable Energy Solutions (RESOLVE) model.

The following analysis is based on sample data collected by the evaluation team. However, due to data quality issues, residential projects have been excluded from this sample. Thus, what follows is a discussion based solely on non-residential data, which makes up 96% of the SGIP storage rebated capacity.

4.1 SAMPLE DATA DESCRIPTION

The results presented in this section are based on modeling and do not reflect actual observed performance of SGIP AES projects. However, to accurately simulate ideal dispatch of SGIP storage projects, the E3 model requires gross load shapes and tariff information for all customers in the sample.

E3 was provided with gross and net load shapes, battery sizes, and tariff information for 248 SGIP non-residential customers.[1] Of those 248 projects, 25 were removed from the sample due to conflicting tariff information or problematic timestamps, rendering an effective sample size of 223 non-residential projects. Forty-six of the projects in the sample were found to be on Critical Peak Pricing (CPP) rates. Because optimal storage dispatching requires knowing the full capabilities of the storage project, the evaluation team elected to model *inverter* capacity, rather than SGIP rebated capacity, in its storage dispatch exercise. Thus, figures reported below reflect the physical capacities of the batteries rather than the program-defined SGIP rebated capacities.

During the data cleaning process, it is often necessary to remove observations that are deemed invalid such as large positive or negative spikes. This means that the final validated dataset may contain missing values where this data cleaning was performed. Of the 223 AES projects in the sample, 141 had 15-minute

[1] Residential projects (representing less than 4% of SGIP rebated capacity) were excluded from this analysis due to the data limitations discussed in Section 3.

load profiles with missing values ranging in duration from less than an hour to multiple days; these gaps had to be filled to create complete profiles for use in RESTORE. E3 filled gaps that spanned one hour or less by taking the simple average of the nearest non-zero data points on either side of the gap. Gaps that spanned more than one hour were filled using the corresponding average observed season-hour-day-type load, where seasons were defined according to the project's IOU tariff. In instances where the project came online midway through the year, modeling was not performed until the project came online.

While most projects were easily mapped to a single rate schedule, 25 out of 223 switched rates once midway through the year, and 13 switched rates more than once during the year. To model these projects accurately, they were assigned special "hybrid" rate structures, reflecting the rate change to the nearest month. For example, one project was on rate E19S for January 1–June 29, 2016 and then on rate A10S for June 29–December 31. This project is modeled such that the rate structure matches E19S for January – June and A10S for July – December.

As our analysis was conducted using a sample of AES projects rather than the entire population, the results had to be scaled up to estimate population-level impacts. Table 4-1 summarizes the sample size used for simulations relative to the population.

TABLE 4-1: SIZE AND REBATED CAPACITY CONTAINED IN SAMPLE VERSUS POPULATION

	AES Sample	AES Population
Number of Projects	223	716
kW of Rebated Capacity	37,593	48,998

To scale our results, we first determined the *effective* annual kW of storage in our sample. Since some storage systems came online midway through 2016, 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 2016 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 savings per effective kW. This value was finally multiplied by the population effective kW to yield estimated total population impacts.

4.2 SIMULATED OPTIMAL DISPATCH WITH DER AVOIDED COSTS

The first approach we use to quantify the potential value of AES is to dispatch storage in an optimization model to minimize bills, utility marginal costs, or GHG emissions. We use utility marginal costs and GHG emissions developed with the E3 DER Avoided Cost Model, adopted by the CPUC to evaluate the costs and benefits of energy efficiency, demand response, and distributed generation.

We sought to understand how storage dispatch could a) minimize ratepayers' retail bills, b) maximize value to the grid, or c) minimize GHG emissions from the electric grid. E3 simulated ideal dispatch by using AES customer load data as inputs to E3's RESTORE model. This analysis quantified the maximum benefits of storage, given a utility rate or dispatch signal. With this result, we evaluated distributed energy storage's potential as a resource.

4.2.1 DER Avoided Cost AES Dispatch Methodology

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] For this analysis, RESTORE optimally dispatched each AES project in the sample three times to minimize impacts from three distinct perspectives:

- **Customer perspective:** Minimize the monthly electricity bill of a given customer, including energy charges and monthly demand charges
- **Utility perspective:** Minimize the system-level cost to serve a given project's electricity demand, including energy, generation capacity, transmission, and renewable portfolio standard (RPS) compliance costs
- **Carbon perspective:** Minimize the GHG emissions impact of a project's electricity demand

Customer Perspective

The objective of the customer perspective was to dispatch the AES project to minimize the customer's aggregated energy and demand charges under the utility rate schedule. We obtained rate information directly from the investor-owned utilities' (IOU) tariff sheets. The underlying AES project details impacting customer perspective results include the specifications of the storage unit (capacity, round-trip efficiency and duration), the customer's load profile, and the utility rate schedule.

Utility Perspective

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. Under the utility perspective, storage was dispatched to maximize the costs avoided by the electric system. Avoided costs were calculated for each IOU and each

[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

15-minute time increment in 2016. The avoided costs used in our analysis are based on the E3 DER Avoided Cost Calculator. The DER Avoided Cost Calculator was most recently updated and adopted by CPUC Resolution E-4801 in September 2016.[3,4] The avoided cost categories included in this analysis are listed in Table 4-2.

TABLE 4-2: AVOIDED COSTS CONSIDERED FOR ANALYSIS

Avoided Cost Type	Data Source
Energy ($/kWh)	CAISO OASIS Day-Ahead location-based marginal prices, NP-15 and SP-15[5]
System Capacity ($/kW-yr.)	E3 Avoided Cost Calculator, by IOU
Transmission ($/kW-yr.)	E3 Avoided Cost Calculator, by IOU
RPS Prices ($/kWh)	E3 Avoided Cost Calculator, by IOU
Ancillary Services ($/kWh)	1% of energy prices (This assumption is consistent with the E3 Avoided Cost Calculator)

Consistent with previous avoided cost analyses performed by E3, the avoided 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 $/kW-year avoided cost of generation capacity is taken directly from the 2016 DER Avoided Cost Calculator. The capacity value is allocated across the 15-minute time intervals of the year, according to each interval's respective likelihood of being one in which additional generation capacity is needed. Thus, avoided system capacity cost is allocated across the year based on CAISO system load, net of renewable generation, using the standard peak capacity allocation factor (PCAF) approach.[6] The specific values used are provided in Table 4-3. 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.

3 CPUC Resolution E-4801 is available at: http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&DocID=167779209

4 2016 DER Avoided Cost Calculator and Documentation available at: https://www.ethree.com/public_proceedings/distributed-energy-resources-der-avoided-cost-proceedings/

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

6 All hours with loads 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 4-3: ASSUMED $/KW-YEAR AVOIDED COST OF GENERATION CAPACITY

IOU	Assumed 2016 Marginal $/kW-year of Generation Capacity
PG&E	$123.39
SCE	$115.49
SDG&E	$115.49

The $/kW-year avoided cost of transmission is also allocated using the PCAF approach; specific values used are provided in Table 4-4. The E3 Avoided Cost Calculator's assumed transmission capacity values come directly from the three IOUs. SDG&E reports a value of $0/kW-year because it does not have a sub-transmission system and therefore has no avoided cost value for transmission capacity.

TABLE 4-4: ASSUMED $/KW-YEAR AVOIDED COST OF TRANSMISSION CAPACITY

IOU	Assumed 2016 Marginal $/kW-year of Transmission Capacity
PG&E	$37.63
SCE	$32.17
SDG&E	$0.00

Note that distribution avoided costs are not included here. We included a separate treatment of distribution system avoided costs to consider the potential value of AES in Distribution Resource Plans (DRP) – see Section 4.3.8

Our $/kWh avoided RPS costs are based on the $/MWh renewable premium prices found in the Avoided Cost Calculator. These are shown in Table 4-5. 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 premium price reflects the cost of procuring and delivering additional renewable energy, per MWh of incremental load.

TABLE 4-5: ASSUMED $/MWH RENEWABLE PREMIUM PRICE FOR DETERMINING RPS PRICE

IOU	Assumed 2016 $/MWh Renewable Premium Price*
PG&E	$43.69
SCE	$45.57
SDG&E	$45.57

* Renewable premium calculation assumes a PPA price of $76.80/MWh in 2016 dollars.

Carbon Perspective

For the carbon minimization perspective, storage is dispatched to reduce carbon emissions. This is accomplished in a manner analogous to that of the utility perspective case, but with the marginal emissions rate, rather than the marginal cost to the utility, as the dispatch signal for AES projects. The marginal emissions rate, driven by market energy prices, varies between northern and southern California. Thus, PG&E has one assumed marginal emissions rate, and SDG&E and SCE have another. Additional details on the marginal emissions dataset used for this analysis are included in Appendix A.

4.3 SIMULATED OPTIMAL DISPATCH RESULTS

The results of our RESTORE optimized dispatch modeling are presented in this section. We first discuss the results broadly, comparing dispatch behavior, battery capacity factors, and total impacts across each of the three optimization perspectives (customer, utility, and carbon, respectively). Subsequent sections delve into more detail on each optimization perspective.

4.3.1 Simulated Optimal Dispatch Timing

Storage dispatch behavior is expected to vary depending on time of day, time of year, and the perspective being modeled. Below we use 12x24 heat maps to illustrate the aggregate AES charging and discharging behavior for the 223 projects in our sample. Green hours indicate that the full sample of AES projects was, in aggregate, discharging; red indicates that they were charging.

The aggregate storage dispatch behavior across the sample of 223 AES projects optimized from the customer's perspective is shown in Figure 4-1. Recall that this perspective optimizes AES dispatch to minimize the sum of customers' energy charges and monthly demand charges, given the retail rate to which they are subject, and an annual gross load profile. An optimization of AES projects' dispatch behavior from the customer perspective shows diffused charging and discharging, and the overall magnitude (in kW) of charging and discharging is relatively low. The periods of charging correspond closely with utility-defined off-peak hours, and the periods of discharging correspond with on-peak hours, indicating that optimal AES dispatch involves TOU period rate arbitrage. The low concentration of dispatch in specific hours reveals that individual customers optimizing their dispatch behavior would discharge to reduce demand charges, and that individual customers' load profiles are diverse.

FIGURE 4-1: OPTIMIZED AES DISCHARGE (CHARGE), AGGREGATED KW ACROSS SAMPLE (N=223) - CUSTOMER PERSPECTIVE

Hour Beginning	Month 1	2	3	4	5	6	7	8	9	10	11	12
0	(10)	(7)	(14)	(17)	(51)	(51)	(63)	(71)	(89)	(75)	(33)	(21)
1	(13)	(10)	(18)	(22)	(56)	(56)	(71)	(82)	(99)	(57)	(42)	(27)
2	(30)	(28)	(38)	(38)	(79)	(67)	(80)	(88)	(108)	(85)	(64)	(46)
3	(183)	(170)	(190)	(182)	(232)	(231)	(247)	(256)	(270)	(256)	(212)	(200)
4	(26)	(25)	(30)	(25)	(71)	(89)	(99)	(106)	(125)	(88)	(64)	(44)
5	(25)	(28)	(21)	(22)	(63)	(69)	(82)	(79)	(99)	(68)	(58)	(43)
6	(21)	(23)	(18)	(20)	(87)	(90)	(101)	(87)	(120)	(81)	(45)	(26)
7	(9)	(13)	(9)	(13)	(78)	(80)	(99)	(100)	(110)	(75)	(17)	(9)
8	3	4	3	31	(1)	(16)	(24)	(18)	(30)	21	35	24
9	3	2	2	11	(9)	(16)	(20)	(20)	(29)	6	14	13
10	4	2	2	11	(10)	4	(18)	(19)	(25)	7	16	15
11	10	3	4	12	(5)	13	(8)	(5)	(14)	20	16	22
12	7	5	5	5	185	269	266	276	332	165	16	10
13	1	5	5	5	70	79	96	140	142	91	15	10
14	4	9	4	3	60	56	97	107	142	79	22	9
15	4	4	1	4	53	132	151	158	177	81	25	8
16	4	12	(0)	9	43	37	88	97	101	83	17	10
17	24	7	8	8	53	66	82	107	109	65	23	35
18	13	6	10	17	2	3	(9)	(15)	(16)	6	18	25
19	107	97	116	101	105	(15)	(10)	(18)	(21)	78	116	121
20	50	30	43	30	39	10	4	(13)	(17)	11	35	46
21	(1)	(2)	(1)	(6)	(21)	(31)	(38)	(40)	(50)	(45)	(8)	(8)
22	(1)	(2)	(5)	(15)	(34)	(41)	(52)	(54)	(64)	(60)	(16)	(14)
23	(9)	(7)	(12)	(18)	(48)	(49)	(69)	(76)	(84)	(78)	(26)	(27)

Ideal dispatch from the utility perspective is shown in Figure 4-2. Modeled AES projects tend to charge during the nighttime and the middle of the day, when both load and energy costs are lower. Discharge tends to occur in the early morning and in the evening, when the utilities' marginal costs are highest. Comparing the utility and customer perspectives illustrates important differences in both timing and magnitude of AES dispatch. When optimizing from the utility perspective, AES projects tended to charge and discharge more energy during fewer hours. This concentrated dispatch behavior is likely due to a more unified avoided cost signal being provided to the utility than to the individual customer (one avoided cost stream per IOU, as opposed to dozens of different customer load profiles and rates) and the higher hour to hour variation in avoided costs as compared to broad retail TOU rate periods.

FIGURE 4-2: OPTIMIZED AES DISCHARGE (CHARGE), AGGREGATED KW ACROSS SAMPLE (N=223) - UTILITY PERSPECTIVE

Hour Beginning	Month 1	2	3	4	5	6	7	8	9	10	11	12
0	47	(8)	(276)	(8)	(16)	(12)	(0)	(90)	(105)	(22)	(182)	(4)
1	(14)	15	(602)	(798)	(691)	(39)	(3)	(193)	(184)	(139)	(181)	(114)
2	(739)	(559)	(735)	(725)	(393)	(972)	(326)	(1,376)	(775)	(1,321)	(627)	(450)
3	(864)	(430)	(271)	(10)	(8)	(37)	(114)	(92)	(33)	(5)	(638)	(1,209)
4	(0)	-	30	2	(0)	1	(1)	-	-	57	(10)	21
5	55	19	63	708	835	456	32	0	37	(123)	19	(75)
6	194	495	1,426	553	118	196	3	(37)	96	1,228	1,093	218
7	586	321	61	(92)	(47)	(23)	(8)	(237)	(109)	-	211	1,098
8	(2)	(0)	(6)	(190)	(155)	(190)	(114)	(342)	(622)	(187)	(10)	61
9	(0)	(0)	(584)	(505)	(388)	(1,338)	(1,623)	(13)	(354)	(271)	(131)	(0)
10	(51)	(0)	200	(1,175)	(1,189)	(272)	(231)	(0)	(83)	(1,799)	(1,245)	(54)
11	(164)	(601)	(869)	(333)	(513)	(267)	(66)	30	(37)	(52)	(214)	(98)
12	(670)	(1,055)	(1,198)	(641)	(445)	(208)	(45)	-	(5)	(60)	(663)	(1,675)
13	(955)	(684)	(950)	(610)	(874)	(71)	0	-	(66)	(49)	(53)	(536)
14	(11)	30	(170)	(567)	(620)	(4)	33	(0)	(2)	(4)	(100)	(36)
15	(0)	(38)	(17)	(192)	(99)	(23)	34	-	0	(32)	(0)	(0)
16	(0)	-	-	(12)	(130)	149	141	113	24	-	0	0
17	1,331	-	-	-	0	389	251	517	536	988	1,603	1,771
18	580	1,815	1,755	100	0	701	1,394	1,293	1,234	844	287	134
19	-	10	261	1,856	2,024	687	96	-	62	111	(65)	-
20	(1)	(71)	(0)	-	0	(3)	(3)	(3)	-	(8)	(32)	(0)
21	10	39	0	-	(0)	-	-	-	-	(68)	74	8
22	(8)	18	(0)	-	(0)	-	-	(8)	-	57	(0)	18
23	(78)	(69)	(4)	(73)	0	-	-	(70)	(36)	(155)	(2)	(0)

The aggregate storage dispatch optimized to minimize carbon shows a charging and discharging pattern that is similar to the utility perspective. The signals that AES projects respond to when minimizing carbon emissions share characteristics with those sent to a utility that is trying to avoid system costs: the signal is concentrated and volatile. However, the variance throughout the middle of the day in marginal emissions rate is higher and less consistent than the marginal cost pattern for utilities. Thus, while Figure 4-2 therefore looks similar in shape and magnitude to Figure 4-2, the charging is more diffuse throughout the middle of the day in the carbon perspective case.

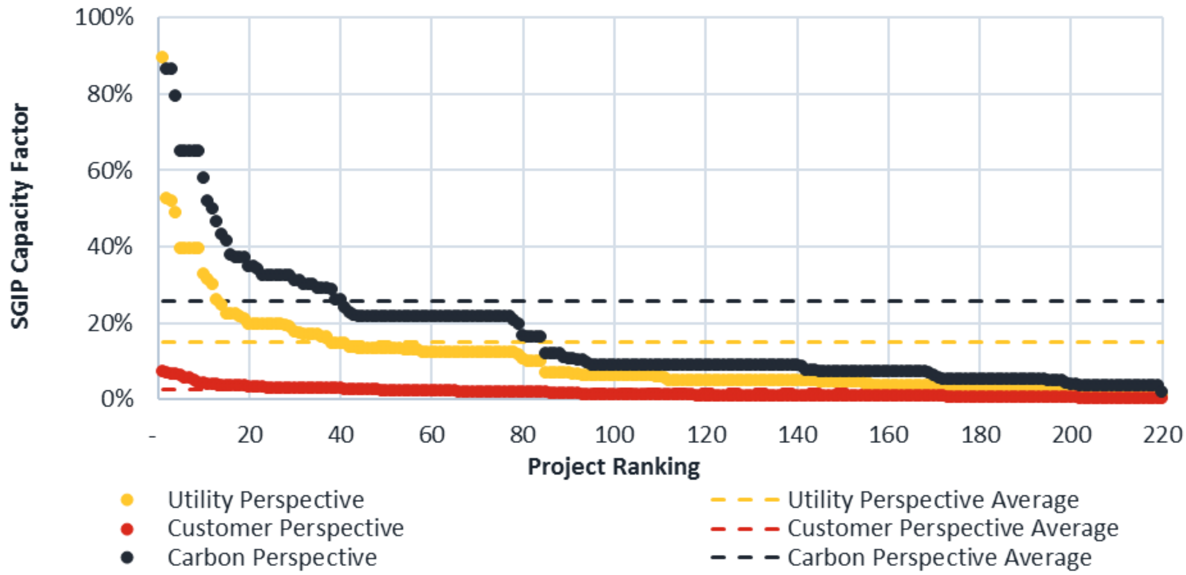
FIGURE 4-2: OPTIMIZED AES DISCHARGE (CHARGE), AGGREGATED KW ACROSS SAMPLE (N=223) - CARBON PERSPECTIVE

Hour Beginning	Month 1	2	3	4	5	6	7	8	9	10	11	12
0	(63)	40	(130)	(188)	(128)	(157)	(211)	(289)	(253)	(318)	(60)	71
1	(102)	(143)	(185)	(356)	(276)	(327)	(288)	(77)	(333)	(536)	(299)	(349)
2	(282)	(102)	(66)	(366)	(640)	(156)	(318)	(439)	(322)	(191)	(249)	(464)
3	(306)	(125)	(251)	14	(55)	(87)	(50)	(150)	(57)	(65)	(60)	(175)
4	(160)	(187)	(439)	(136)	374	217	285	308	107	(16)	(253)	(54)
5	139	353	330	(5)	287	(75)	(206)	283	524	519	193	(87)
6	187	92	353	423	(143)	(65)	(163)	116	198	397	615	538
7	75	(93)	(137)	(74)	(159)	(297)	(542)	(431)	(185)	(42)	(144)	233
8	84	(332)	(115)	34	(113)	(153)	(212)	(464)	(217)	(340)	(188)	2
9	(164)	(366)	(85)	(397)	(143)	(297)	(13)	(90)	(450)	(341)	(213)	(186)
10	(10)	(356)	(107)	(14)	(234)	(370)	(162)	(166)	(584)	(312)	(151)	(40)
11	(578)	149	(158)	(217)	(66)	(61)	(219)	(253)	(87)	108	(236)	(288)
12	(294)	(117)	(61)	(326)	(115)	(40)	(63)	(121)	(238)	(135)	(220)	(174)
13	(397)	(268)	96	(304)	(337)	(11)	28	15	105	(197)	(287)	(240)
14	7	(433)	(224)	(181)	(311)	(73)	10	34	(138)	(468)	(761)	(771)
15	(124)	(694)	(610)	(61)	(273)	(166)	(51)	119	(438)	(219)	(6)	(441)
16	22	242	(1,455)	(614)	(309)	(46)	(46)	52	183	49	56	(164)
17	132	89	261	376	18	162	497	654	363	192	343	455
18	136	249	277	(83)	402	413	497	274	207	18	189	172
19	222	124	234	85	41	(118)	17	83	15	161	198	79
20	(30)	188	250	192	80	146	(46)	(177)	(66)	20	21	114
21	49	26	251	7	(11)	250	6	(136)	(79)	114	(205)	129
22	103	114	(290)	(375)	(372)	(424)	(192)	(436)	(123)	(191)	(201)	(63)
23	(153)	(164)	(181)	(77)	43	(160)	20	(172)	(22)	(135)	(273)	(277)

4.3.2 Capacity Factors and Roundtrip Efficiencies Under Optimized AES Dispatch

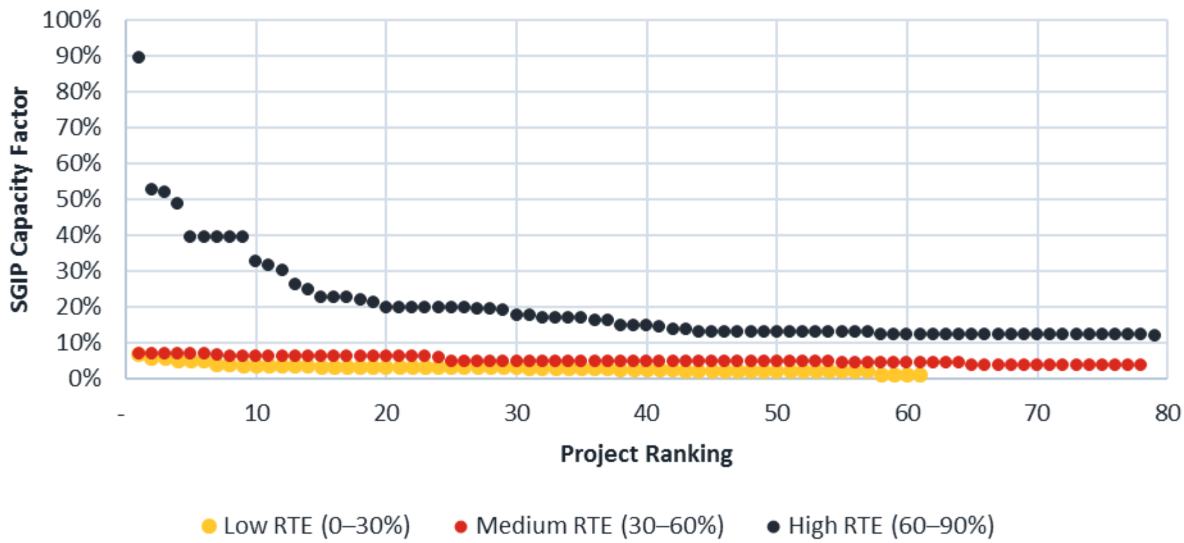
In addition to comparing aggregate battery dispatch, we examined how much the simulated AES projects are being utilized by comparing capacity factors across the perspectives. The SGIP capacity factor represents the ratio of actual discharge to maximum possible discharge over 60% of hours, and is a measure of how much a system is utilized relative to its maximum potential. Higher volatility in signals leads to greater opportunities for arbitrage. Marginal costs and carbon emissions fluctuate on a sub-hourly basis whereas TOU rates stay the same for multiple hours; therefore, the simulated capacity factors for the utility and carbon perspectives are generally higher than the capacity factors for the customer perspective. Results are summarized in Figure 4-3.

FIGURE 4-3: AES PROJECT SGIP CAPACITY FACTORS ASSUMING OPTIMAL DISPATCH, BY PERSPECTIVE (N=223)



AES round-trip efficiency is also an important consideration related to system utilization. AES projects with higher RTE can realize benefits from smaller spreads between arbitraged values because the amount of possible discharge will be a larger fraction of the charge going into the battery. As shown in Figure 4-4, under optimal dispatch that minimizes marginal utility costs, projects with high RTE (60 – 90%) would consistently have higher capacity factors than those with medium RTE (30% - 60%), which in turn have higher capacity factors than low RTE (0 – 30%) projects. It should be noted that this analysis relies on a single round-trip efficiency input for each project, based on the observed efficiencies from the AES performance data collected over the evaluation period. The dispatch model assumes losses only when the AES is charging or discharging. The model does not separately account for parasitic losses, which occur regardless of whether the AES is charging or discharging. By not separately modeling parasitic losses, the analysis slightly overstates the capacity factors possible with ideal dispatch.

FIGURE 4-4: AES PROJECT CAPACITY FACTORS ASSUMING OPTIMAL DISPATCH, BY OBSERVED ROUND-TRIP EFFICIENCY (RTE) BIN - UTILITY PERSPECTIVE (N=223)



4.3.3 Maximum Potential Customer Bill Savings Attributable to AES Projects

In order to understand the range of benefits that SGIP storage could potentially have provided in 2016, we analyzed the savings attributable to AES projects on a per-kW inverter capacity basis *if they were optimally dispatched according to each perspective*. 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 $483/kW) in 2016. Total potential savings to customers across the population of SGIP AES projects would have been approximately $4.9 million in 2016. On average, this would amount to an annual bill savings of about $9,000 per storage project. (Note: this average is based solely on our usable sample of non-residential customers. Residential customers would not expect as large of a bill reduction.) Notably, the customer perspective is the only one that would have resulted in bill savings under 2016 utility rates: optimizing AES dispatch to minimize utility marginal costs or to minimize carbon would have led to a substantial increase in customer bills. This suggests a potential mismatch between customer and utility/societal incentives for storage dispatch.

FIGURE 4-5: DISTRIBUTION OF ANNUAL ELECTRICITY BILL SAVINGS ATTRIBUTABLE TO AES PROJECTS UNDER OPTIMAL DISPATCH, BY OPTIMIZATION PERSPECTIVE, $ PER KW OF INVERTER CAPACITY (N=223)

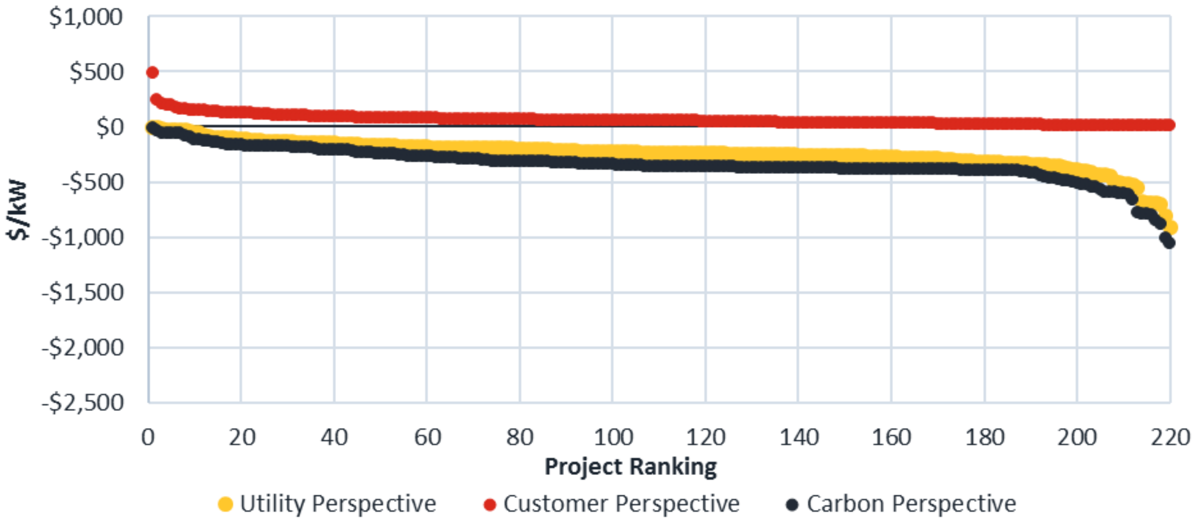
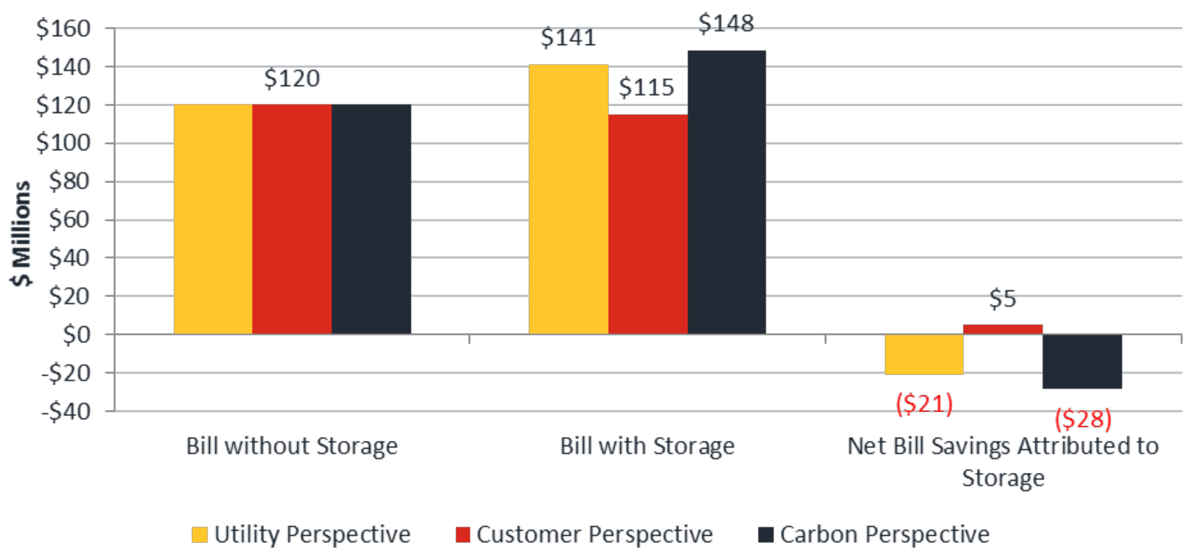


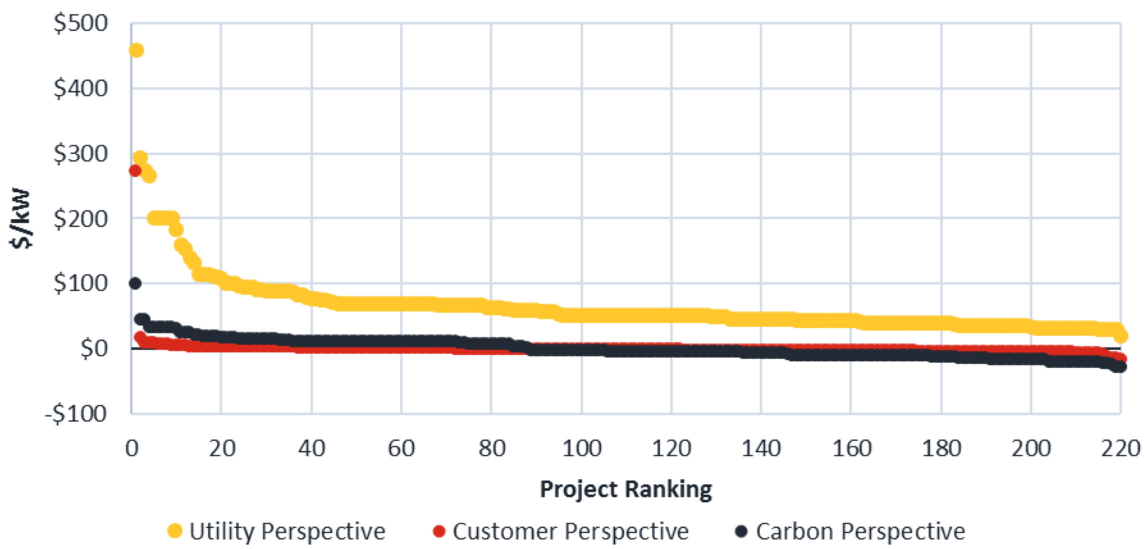
FIGURE 4-6: ESTIMATED 2016 BILL SAVINGS ATTRIBUTABLE TO THE POPULATION OF AES PROJECTS OPERATING IN 2016 UNDER OPTIMAL DISPATCH, BY PERSPECTIVE ($ MILLIONS)



4.3.4 Potential Utility Cost Savings Attributable to AES Projects

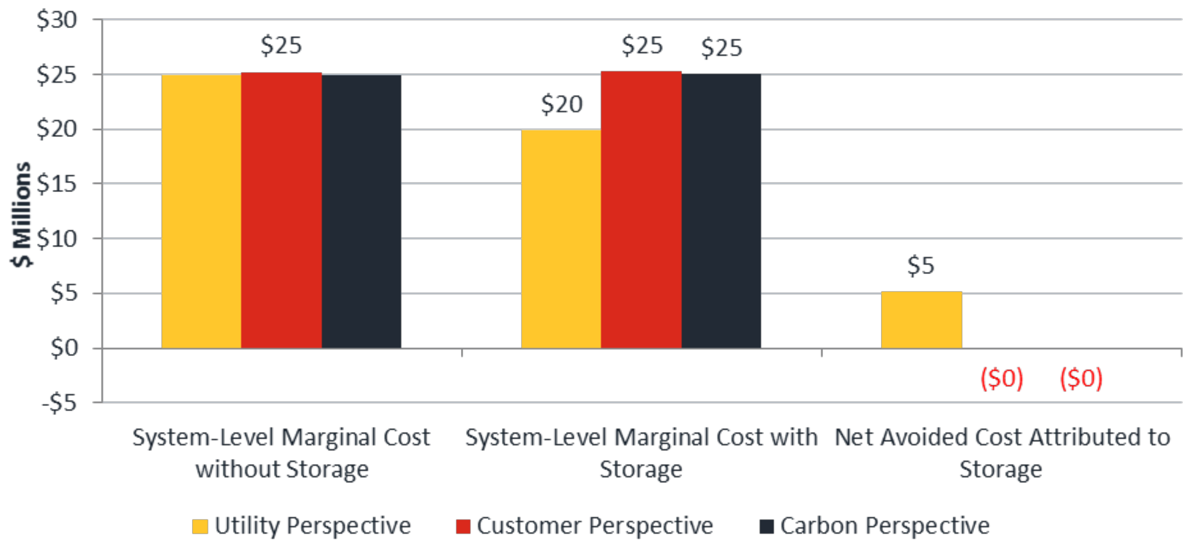
Our analysis of the sample of 223 AES projects revealed that the system-level savings that could potentially have been realized in 2016 range from $0/kW to $273/kW *if* the projects were dispatched to minimize marginal utility costs (Figure 4-7). Each marker on the figure represents an AES project in our sample. Most potential values are above $50/kW.

FIGURE 4-7: DISTRIBUTION OF UTILITY AVOIDED COSTS ATTRIBUTABLE TO AES PROJECTS UNDER OPTIMAL DISPATCH, BY OPTIMIZATION PERSPECTIVE, $ PER KW OF INVERTER CAPACITY (N=223)



As shown in Figure 4-8, scaling up our 223-project sample to a population estimate yields significant system cost savings: if the full population of SGIP AES projects operating in 2016 were optimized on a 15-minute basis to minimize utility costs, we estimate that we would have seen a net avoided cost to the system of over $5 million in 2016. According to our modeling, optimizing the dispatch of the full population of AES projects to minimize carbon would have yielded a net system cost of about $0.1 million in 2016. Optimizing dispatch against customer bills yields an even slighter cost to the system.

FIGURE 4-8: ESTIMATED 2016 UTILITY AVOIDED COSTS ATTRIBUTABLE TO THE POPULATION OF SGIP AES PROJECTS OPERATING IN 2016 UNDER OPTIMAL DISPATCH, BY OPTIMIZATION PERSPECTIVE, $ MILLIONS



4.3.5 Potential GHG Savings Attributable to AES Projects

Optimizing AES dispatch to minimize GHG emissions results in emissions savings from every AES project in our sample, with savings ranging from 1.93 tons/kW to 0.05 tons/kW. In other words, all systems included in our sample can reduce GHG emissions if optimized to do so (see Figure 4-9). Correspondingly, the total avoided GHG emissions amounts to around 19,000 metric tons of CO_2; the utility perspective also results in some carbon savings (nearly 500 tons), while the customer perspective increases CO_2 emissions by around 1,400 tons.

FIGURE 4-9: DISTRIBUTION OF GHG EMISSIONS SAVINGS ATTRIBUTABLE TO AES PROJECTS UNDER OPTIMAL DISPATCH, BY DISPATCH PERSPECTIVE, METRIC TONS GHG PER KW OF INVERTER CAPACITY (N=223)

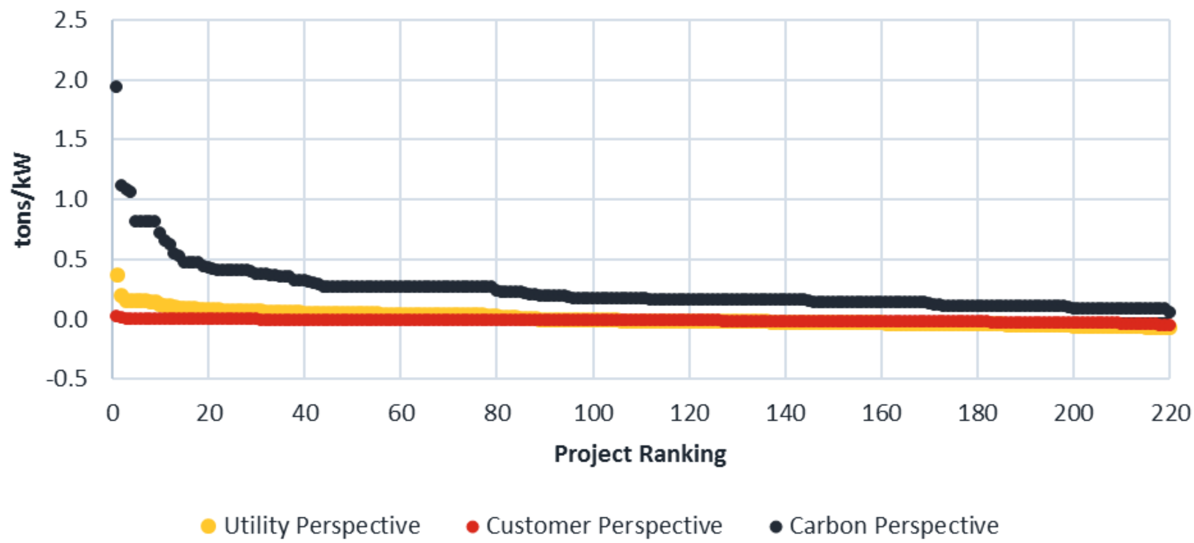
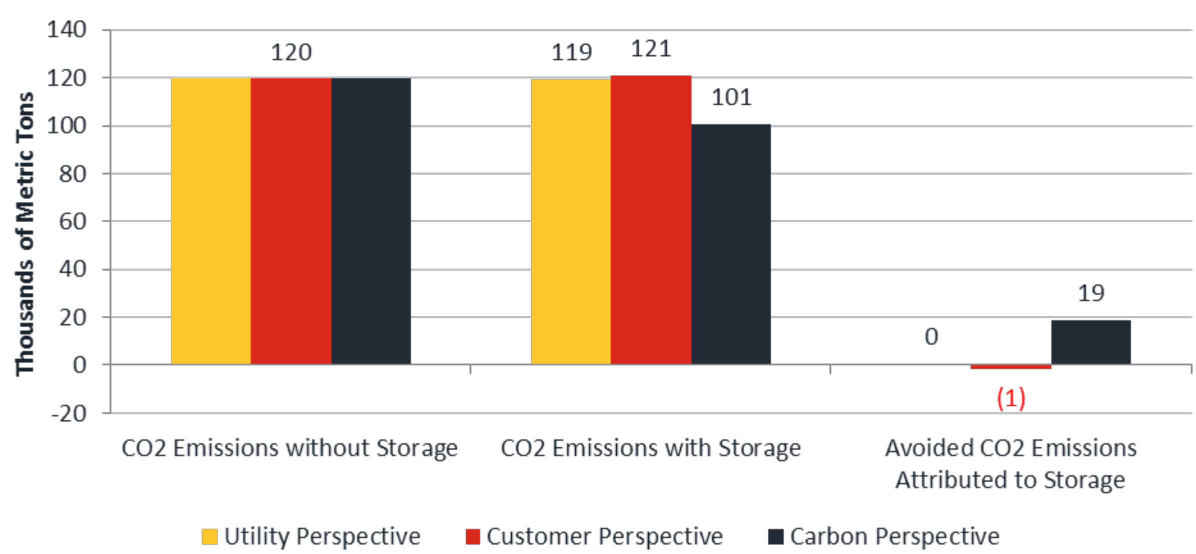


FIGURE 4-10: ESTIMATED 2016 AVOIDED GHG EMISSIONS ATTRIBUTABLE TO THE POPULATION OF SGIP AES PROJECTS OPERATING IN 2016 UNDER OPTIMAL DISPATCH, BY DISPATCH PERSPECTIVE, THOUSAND METRIC TONS GHG



4.3.6 Summary Results of Ideal Marginal Cost Dispatch

The total potential savings attributed to SGIP AES projects under ideal dispatch are summarized in Table 4-6 below.

TABLE 4-6: ESTIMATED POPULATION-LEVEL IMPACT OF AES PROJECTS, 2016

	Customer Perspective	Utility Perspective	Carbon Perspective
Net Bill Savings ($ Millions)	$4.9	($20.8)	($28.4)
Net Avoided Cost Benefit/(Cost) ($ Millions)	($0.0)	$5.1	($0.1)
Avoided GHG Emissions (Metric Tons)	(1,419)	448	18,804

Under customer dispatch to minimize bills, simulated customer bill savings for 2016 for 95.5 MW of AES *inverter* capacity (not SGIP rebated capacity, based only on a non-residential sample) are $4.9 million. Potential savings translate to about $9,000 saved annually per storage project, or a 7% bill reduction. (Note: this average is based solely on our usable sample of non-residential customers. Residential customers would not expect as large of a bill reduction.) However, AES dispatched from the customer perspective increases grid costs and GHG emissions by $16,000 and 1,419 metric tons respectively. AES dispatched from the utility perspective to minimize grid costs provided net benefits of $5.1 million and reduces GHG emissions by 448 metric tons. However, under existing rates, customer bills would increase by $20.8 million. Finally, AES dispatch to minimize GHG emissions could realize a reduction of nearly 19,000 metric tons, with slight system cost and a larger customer bill impact of $28.4 million.

These results demonstrate that, under current 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. More dynamic rates that better align customer and grid benefits could provide substantial ratepayer and environmental benefits that are currently unrealized.

4.3.7 TOU Rates vs. Marginal Costs

CPUC avoided costs developed for DERs represent the marginal cost of delivering energy in each hour, including an allocation of system, transmission, and distribution capacity costs to peak load hours (See Section 4.2.1). Figure 4-11 shows the average hourly CPUC avoided costs for DER overlayed with the SCE TOU periods in 2016. Figure 4-12 shows revised TOU periods proposed by SCE in the CPUC Residential Rate Reform Proceeding and CPUC avoided costs for 2030, reflecting higher penetrations of renewable generation.[7]

[7] CPUC Rulemaking 12-06-013

FIGURE 4-11: 2016 SCE TOU PERIODS AND AVERAGE HOURLY CPUC AVOIDED COSTS FOR DER IN 2016 (PACIFIC LOCAL TIME, HOUR ENDING) [8]

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
1	$43	$41	$33	$38	$38	$39	$42	$44	$45	$47	$52	$53
2	$42	$39	$32	$36	$37	$38	$41	$42	$43	$45	$51	$52
3	$41	$38	$31	$35	$36	$38	$40	$41	$42	$44	$50	$51
4	$41	$38	$32	$37	$37	$38	$40	$42	$43	$46	$51	$52
5	$42	$40	$35	$43	$41	$40	$42	$44	$46	$49	$54	$54
6	$47	$46	$40	$48	$43	$42	$42	$46	$48	$53	$60	$62
7	$51	$49	$42	$46	$40	$41	$42	$46	$48	$54	$65	$69
8	$52	$49	$38	$37	$33	$38	$42	$44	$46	$50	$59	$71
9	$47	$45	$33	$30	$29	$40	$43	$45	$46	$47	$51	$59
10	$44	$41	$31	$29	$30	$41	$44	$46	$47	$48	$48	$53
11	$44	$40	$31	$31	$30	$43	$45	$48	$49	$49	$47	$48
12	$43	$39	$31	$32	$31	$45	$48	$51	$51	$51	$48	$47
13	$42	$39	$31	$32	$30	$46	$51	$53	$53	$52	$47	$46
14	$41	$38	$32	$32	$31	$48	$53	$77	$538	$54	$47	$46
15	$42	$39	$32	$33	$31	$50	$56	$289	$910	$58	$49	$47
16	$44	$41	$35	$36	$34	$54	$60	$530	$1,266	$72	$52	$55
17	$55	$46	$40	$41	$38	$55	$60	$596	$1,166	$72	$65	$67
18	$66	$56	$46	$50	$46	$60	$61	$331	$1,899	$87	$85	$87
19	$66	$65	$54	$58	$52	$62	$62	$521	$1,175	$76	$77	$84
20	$61	$58	$50	$62	$59	$60	$60	$157	$327	$65	$68	$76
21	$58	$56	$45	$53	$53	$54	$56	$55	$55	$58	$65	$72
22	$54	$51	$41	$48	$46	$48	$51	$52	$51	$55	$60	$66
23	$50	$47	$38	$43	$42	$44	$48	$48	$49	$52	$57	$62
24	$46	$44	$34	$41	$39	$41	$45	$46	$47	$48	$52	$57

There are two key challenges for TOU rates with respect to incentivising AES dispach. The first is properly aligning the TOU periods for peak loads net of PV generation that are occuring later in the evening. The second challenge, with respect to AES, is that 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.

[8] 2016 CPUC avoided costs for climate zone 9: Burbank-Glendale

FIGURE 4-12: PROPOSED SCE TOU PERIODS AND AVERAGE HOURLY CPUC AVOIDED COSTS FOR DER IN 2030 (PACIFIC LOCAL TIME, HOUR ENDING) [9]

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
1	$105	$106	$98	$100	$97	$97	$100	$103	$101	$107	$116	$112
2	$102	$101	$95	$95	$93	$95	$98	$95	$97	$102	$113	$110
3	$100	$99	$94	$93	$90	$93	$95	$93	$95	$101	$111	$107
4	$100	$97	$98	$99	$94	$94	$96	$94	$97	$104	$113	$109
5	$104	$102	$108	$118	$105	$100	$100	$102	$106	$113	$119	$114
6	$117	$123	$127	$134	$111	$105	$102	$108	$112	$122	$135	$128
7	$128	$131	$137	$126	$102	$102	$101	$107	$112	$124	$144	$148
8	$129	$132	$120	$97	$14	$95	$99	$99	$103	$113	$129	$152
9	$118	$119	$100	$14	$14	$99	$102	$101	$103	$108	$113	$122
10	$109	$106	$14	$14	$14	$15	$106	$107	$107	$110	$105	$111
11	$107	$102	$14	$14	$14	$18	$110	$112	$113	$115	$102	$99
12	$105	$101	$14	$15	$15	$22	$114	$118	$117	$118	$105	$98
13	$102	$99	$14	$15	$15	$24	$121	$124	$123	$121	$102	$95
14	$100	$99	$15	$17	$15	$29	$129	$132	$133	$126	$103	$95
15	$102	$101	$15	$17	$15	$33	$137	$138	$306	$135	$107	$98
16	$110	$107	$108	$18	$16	$142	$147	$154	$1,347	$145	$115	$112
17	$135	$122	$127	$112	$17	$145	$151	$576	$2,883	$239	$146	$144
18	$171	$154	$152	$139	$121	$158	$154	$501	$2,851	$214	$195	$189
19	$172	$182	$183	$165	$139	$162	$153	$664	$1,584	$185	$177	$183
20	$156	$160	$166	$174	$160	$160	$147	$256	$520	$154	$155	$164
21	$150	$152	$146	$150	$141	$142	$137	$126	$130	$138	$147	$152
22	$133	$137	$131	$132	$122	$121	$126	$122	$121	$129	$134	$142
23	$124	$123	$118	$118	$108	$113	$112	$116	$117	$117	$125	$133
24	$114	$116	$103	$110	$101	$104	$105	$108	$109	$110	$116	$120

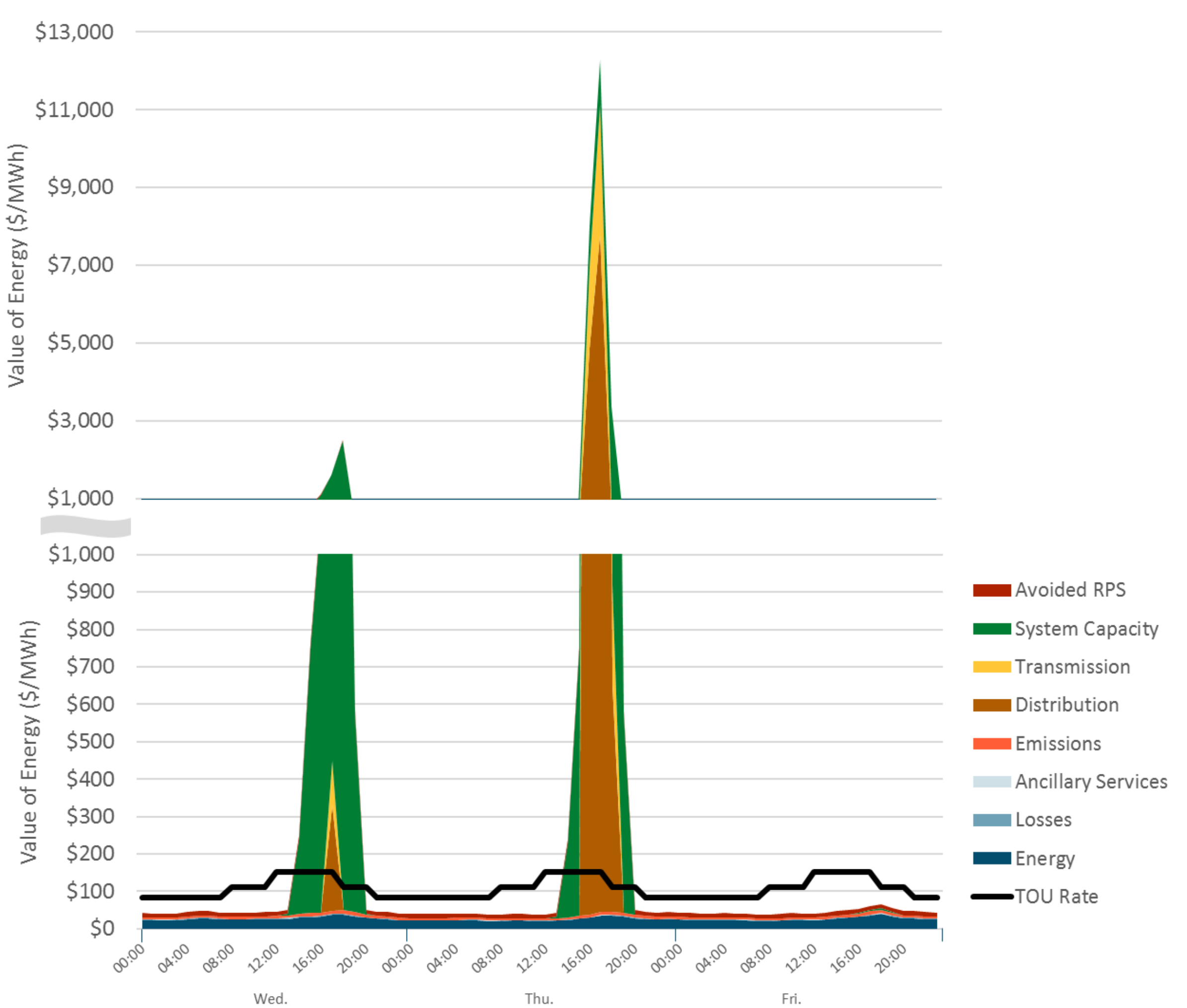
Modifying TOU periods to account for excess solar generation during the day and peak net loads that occur later in the evening is under active consideration in the CPUC Residential Rate Reform Proceeding. Shifting the TOU period to later in the day will capture more of the high system marginal costs hours (e.g., hour ending (HE) 19 and HE 20 in August and September) that fall outside the current on-peak TOU period. SCE has also proposed a super off-peak period in the winter between HE 9 and HE 16 when excess renewable generation is most likely to occur.

Broad TOU rate periods, however, do not harness the potential for highly flexible resources like AES to support the grid during those specific hours with the highest marginal costs. Figure 4-13 shows an example PG&E TOU rate (E19S) compared to the 2016 CPUC avoided costs in Fresno for three summer days. On the first day, high system capacity value is concentrated in the three hours between 5 and 8 PM, but the TOU rate provides an equal incentive for AES to discharge beginning at noon. The next day, local transmission and distribution capacity costs drive a significantly higher value concentrated between 4 and

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

6 PM. Focusing AES discharge in just those two hours based on local system conditions would maximize the value to the grid. For the last day, the difference between on- and off-peak marginal costs are relatively small. Charging AES off-peak and discharging on-peak reduces the customer bill, but provides limited value to the grid on this particular day.

FIGURE 4-13: THREE DAY SNAPSHOT OF PG&E TOU RATES AND CPUC AVOIDED COSTS IN 2016[10]



The following sections provide additional detail on the results from the three optimization perspectives.

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

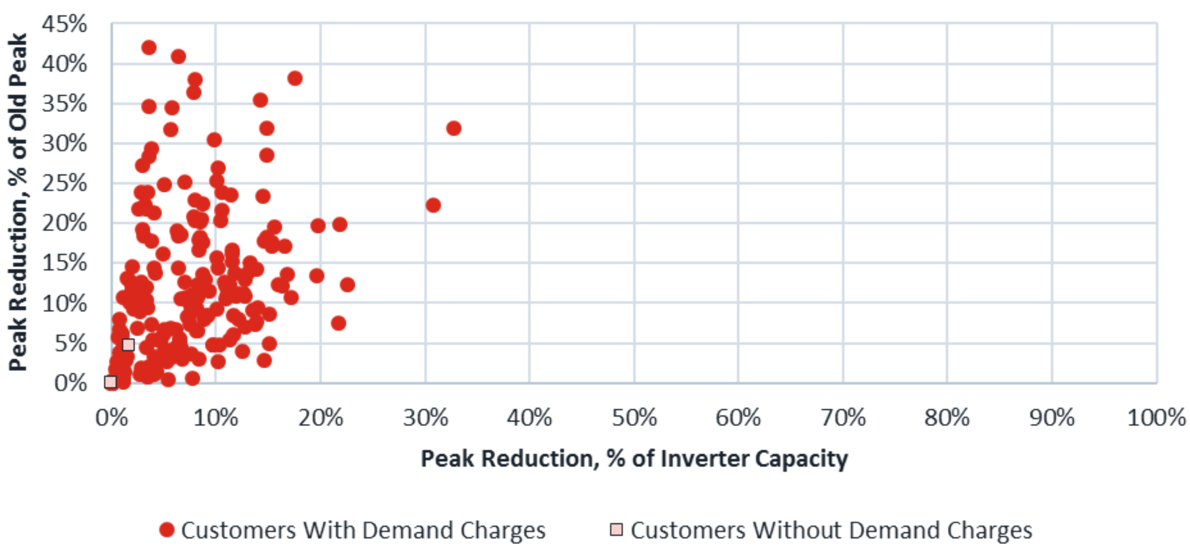
4.3.8 Drilling Down on the Customer Perspective

Earlier in this report, the evaluation team discussed the empirical evidence suggesting that customers used their AES projects to provide bill savings in 2016. In this section, we will focus on the conclusions that can be drawn about the impact of customer retail rates on optimal storage dispatch across the familiar metrics of system cost, bill savings, and carbon emissions.

As discussed earlier, the population of SGIP AES projects operating during 2016 would have produced $4.9 million in bill savings if dispatched to minimize customer bills. These savings come from a combination of demand charge minimization and TOU period rate arbitrage.

Figure 4-14 provides the range of peak demand reductions achieved with AES under optimal customer dispatch, displayed both as a percentage of capacity and as a percentage of the customer's avoided peak demand. Note that customers without demand charges display little, if any, peak demand reduction. For customers subject to demand charges, however, the results are widely varying. Some can reduce peak demand by nearly half. However, most exhibit peak demand reductions between 5% and 25% of the avoided peak demand. The ability to reduce peak demand is a function of two factors: the load profile of the customer and the opportunity cost of TOU rate arbitrage.

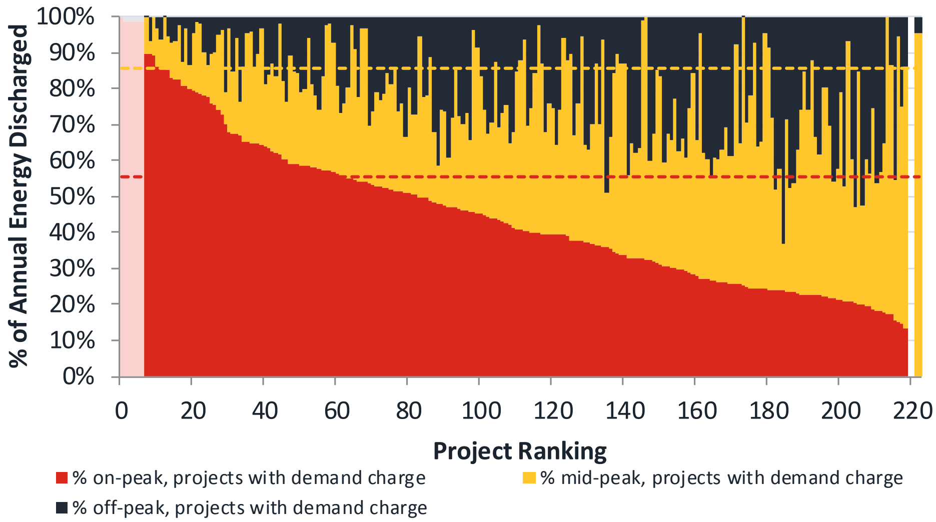
FIGURE 4-14: PEAK DEMAND REDUCTION ATTRIBUTED TO AES, CUSTOMER DISPATCH PERSPECTIVE



Two customers under the same rate schedule can differ dramatically in their abilities to reduce peak demand if, say, one customer has a low, flat load profile for most of the day with a dramatic one-hour spike, whereas the other has a flat, but high-demand, load profile. While the goal of demand charges is to minimize the need for generation capacity, they are not always effective at reducing demand in peak system hours. Though system and local capacity is constrained in a small percentage of hours throughout the year, in the above example, the former customer has an incentive to dispatch storage during its peak hour, but the latter faces no such incentive.

Furthermore, reducing peak demand can sometimes come at the opportunity cost of TOU period arbitrage. A commercial customer whose demand peaks in the morning may prioritize discharging at that time to reduce a demand charge, or may instead elect to discharge energy later in the day, during an on-peak TOU period, offsetting the higher volumetric cost. Likely, if the customer is dispatching to minimize their bill, they would in fact operate somewhere in between, discharging to reduce peak to the extent possible, and otherwise maximizing TOU period rate arbitrage (Figure 4-15).

FIGURE 4-15: STORAGE DISCHARGE BY TOU PERIOD, CUSTOMER DISPATCH PERSPECTIVE



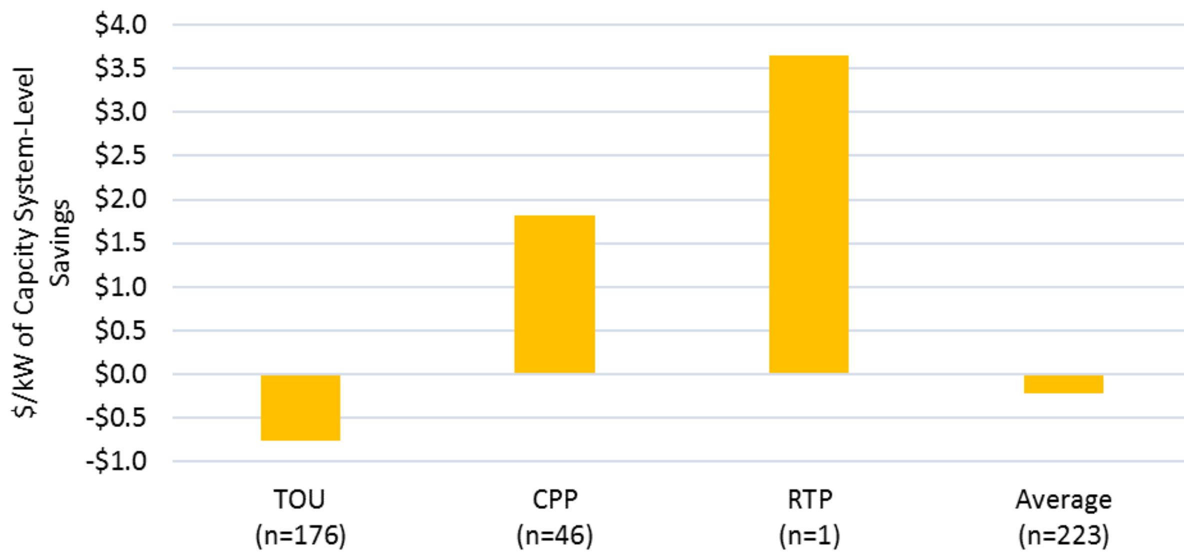
lighter shade denotes projects whose rates **do not have demand charges*

Figure 4-15 displays the timing, by TOU period, of each storage project's discharged energy, in percentage terms. Unsurprisingly, just as Figure 4-14 showed that under optimized dispatch customers without demand charges would do little to reduce peak demand, Figure 4-15 shows that they would devote their AES projects to discharging entirely on-peak. For the remaining projects, the extent to which TOU rate arbitrage would be given priority is wide-ranging. While some devote the majority of their discharging to on-peak hours, *no* customers would discharge entirely on-peak and most would discharge less than 50% of their energy on-peak. The average energy discharged on-peak is 56%; the average energy discharged at mid-peak is 29%, as indicated by the dashed lines.

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 demand charges can undermine the extent to which the timing of customers' load can be influenced. Demand charges are effective in incentivizing reduction in peak power consumption but while demand charges will incentivize customers to reduce their peak demand, they will not necessarily do so in the hours in which a utility most needs a demand reduction. In fact, demand charges can incentivize customers to maintain low energy consumption in hours in which it would actually be beneficial to charge their AES projects. Demand charges with underlying time-variant rates would help to combine the best of both billing determinants.

To further convey the importance of high-resolution signaling to customers about the marginal costs of supplying energy, we analyzed the impact on system-level costs under the customer perspective by different rate types. These results are summarized in Figure 4-16 below.

FIGURE 4-16: SYSTEM-LEVEL SAVINGS PER KW OF AES INVERTER CAPACITY UNDER CUSTOMER PERSPECTIVE BY RATE TYPE



Though only one customer in the sample was subject to a real-time price (RTP) retail rate, the disparity between the RTP and CPP customers,[11] compared to traditional TOU customers, is dramatic. Whereas TOU customers on average increase grid costs under today's rates, storage dispatch behavior for CPP and RTP customers actually provides *benefit* to the grid.

[11] The real-time price rate varies on an hourly and daily basis, depending on the temperature in the area where the customer is located. Critical peak pricing customers are subject to a handful of days throughout the year in which they are penalized more dramatically for higher loads.

4.3.9 Drilling Down on the Utility Perspective

In optimizing AES dispatch to minimize utility avoided costs we quantified a potential value of $5.1 million in 2016. However, under current 2016 rates, utility perspective dispatch would have resulted in a $20.8 million increase in customer bills. Retail rates for AES customers need to be better aligned with hourly or sub-hourly avoided costs to maximize grid value and to avoid an increase in bills for customers that dispatch for grid benefits, as discussed previously.

When optimizing to maximize avoided costs to the electricity system, our analysis showed that AES can provide at best $457 system value per kW of inverter capacity in 2016, depending on the specifications of the AES project. Scaling to the population capacity for the SGIP program in 2016, we estimate a total of $5.1 million in system avoided costs in 2016. With an assumed 10 years of lifetime for each storage project (excluding degradation), and a 7% discount rate, extending this value over ten years produces a lifetime potential savings of $35 million in system avoided costs, as summarized in Table 4-7. Given the 95,493 kW of non-residential storage *inverter* capacity in the SGIP population, this produces a potential lifetime value of $375 per kW of inverter capacity.

TABLE 4-7: LIFETIME VALUE OF AES

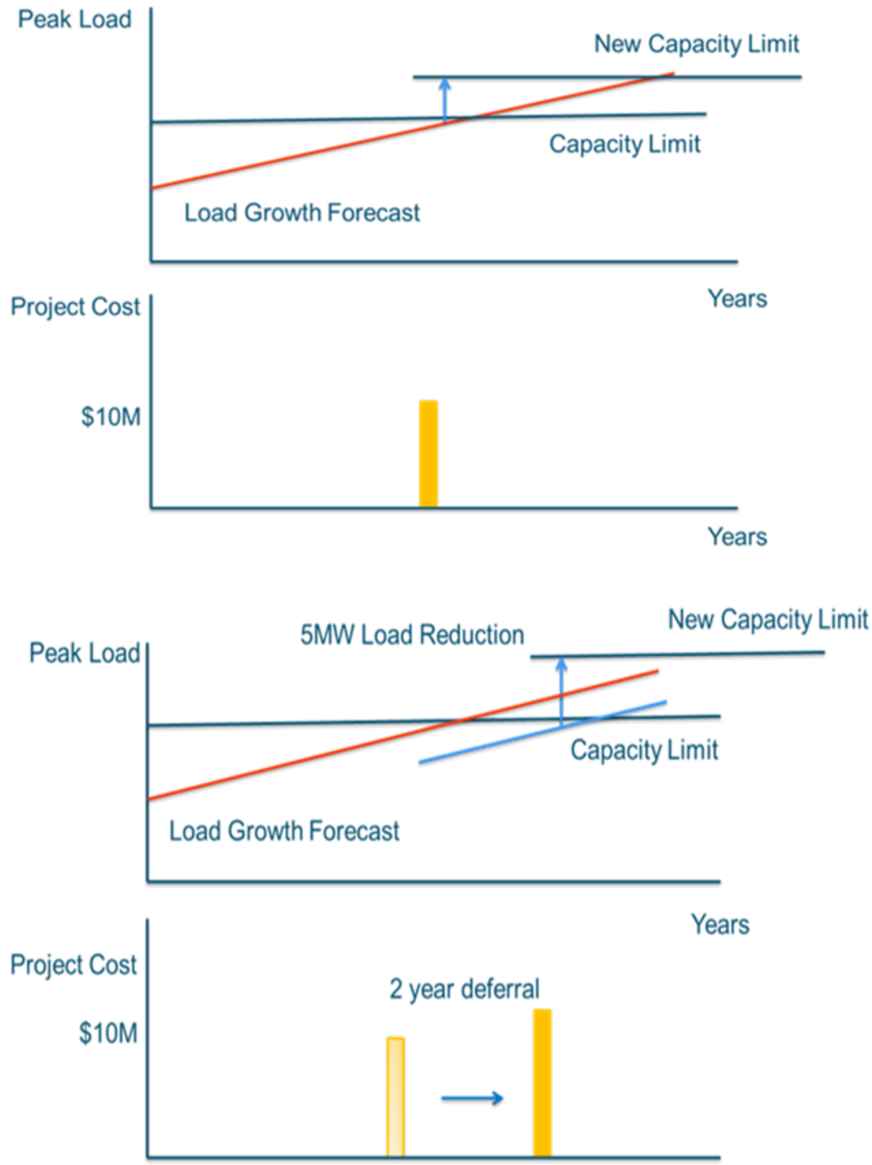
	Estimated Population System Value, 2016$	Estimated Population System Value, 10-year lifetime, NPV 2016$	Estimated Population System Value, lifetime per kW inverter capacity
NPV 2016$	$5.1 million	$35.8 million	$375/kW

Characterizing the Potential Value of Distribution Upgrade Deferral

There is additional value available from distributed storage due to its ability to influence local distribution system costs. This value stream was not modeled in this report. Cost and value potential at the distribution level are far more varied than at the system level, and accurately modeling these is far more dependent on assumptions. Rather than modeling these granular details, the analysis discussed below aims to characterize the broad potential for an individual system to produce value in deferring a distribution upgrade.

The value of avoiding or delaying a distribution infrastructure investment can be calculated using the present worth method, which involves calculating the difference in net present value between the revenue requirement of local area investments before and after AES is installed. By lowering peak load, investments that would have otherwise been made to upgrade distribution equipment can potentially be deferred for a number of years. The difference in net present value between an immediate upgrade and a deferred one is the calculated value of deferral. This interaction is depicted in Figure 4-17.

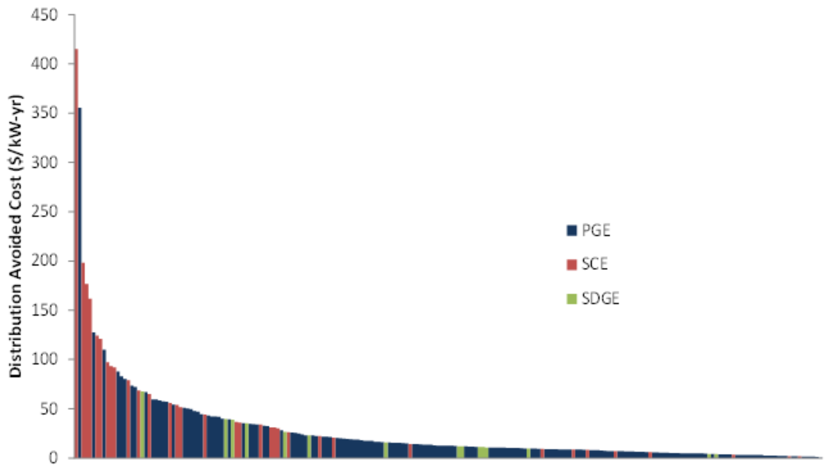
FIGURE 4-17: ILLUSTRATION OF THE VALUE OF UPGRADE DEFERRAL



In this example, a 5MW reduction in load defers a $10 million upgrade by two years. With an assumed discount rate of 7%, the value of this deferral is about $1 million. By dividing the value of the deferral by the amount of load reduction required to achieve the deferral, a distribution marginal cost of load is calculated to be $200/kW-year.

This methodology was applied by E3 on distribution feeders for the three California IOUs in 2012 as part of a study on the technical potential for DERs.[12] The result was a distribution of local marginal costs associated with feeder upgrades. This distribution is presented in Figure 4-18.

FIGURE 4-18: DISTRIBUTION AVOIDED COSTS BY IOU, $ PER KW-YR



In the figure above, several locations show very high distribution avoided costs (greater than $100/kW-year), with several displaying more moderate magnitudes ($40-$100/kW-year), and most with very low magnitudes (less than $40/kW-year).

Combining these distribution avoided costs with the system avoided cost described in Table 4-7 above ($375/kW) provides an approximation of total utility value for AES, as seen in Table 4-8.

TABLE 4-8: TOTAL UTILITY AVOIDED COST FROM AES

Distribution Need for AES	Distribution System Avoided Cost, $/kW-year	Distribution System Avoided Cost, $/kW	Total Avoided Cost, $/kW (includes system-level savings of $375/kW)
Severe	$100 - $425	$702 - $2,985	$1,077-$3,360
Moderate	$40 - $99	$281 - $695	$656-$1070
Low	$0 - $39	$0 - $274	$375-$649

[12] Energy and Environmental Economics. Technical Potential for Local Distributed Photovoltaics in California Preliminary Assessment http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html. 1 March 2012.

The above values convey the range of possible value propositions to the California grid of AES. The distribution upgrade deferral value of any one AES project is highly dependent on the need for distribution solutions at the local level.

Analytical Limitations of the Utility Perspective Analysis

There are two important limitations to this Utility Perspective valuation. First, the above analysis operates under the assumption of perfect foresight to dispatch AES to minimize system costs. This approach does not investigate the infrastructure required to enhance communication between system operators and storage dispatchers to a sophisticated enough level as to make this dispatching a reality. Beyond mere technological enhancements, the signal being directed to electricity end users must also be improved.

Second, the above discussion on distribution-level benefits 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.

4.3.10 Drilling Down on the Carbon Perspective

As noted previously, minimizing system costs is correlated with minimizing emissions, so the utility perspective results in net emissions savings: reducing marginal costs to the system as a whole will also tend to have emissions benefits. However, under current utility tariffs, reducing customer bills is at odds with reducing emissions. Current TOU rates tend to ramp up in the afternoon, meaning that the cost of electricity to the customer is high when it is still daytime and the state is seeing significant solar generation. This leads to hours where the customer’s rate is not well matched with the true marginal cost of electricity and therefore is not well aligned with hours having high marginal emissions. Should TOU rates become more directly linked to marginal costs, carbon emission avoidance would be improved. We expect there could then be instances where AES simultaneously results in savings for the system, customers, and emissions.

4.4 LONG-TERM INTEGRATED RESOURCE PLANNING AES VALUE RESULTS

The second approach we use to quantify potential benefits is a long-term integrated resource planning approach with E3's Renewable Energy Solutions (RESOLVE) model. This approach is being used in the CPUC Integrated Resource Planning Proceeding. In this approach, the addition of AES reduces both long-term capital investment and variable operating costs to minimize total costs for the electric grid.

4.4.1 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 value proposition of integrated resource planning is to reduce the cost of achieving these statewide policy goals by looking across individual load serving entity (LSE) boundaries and resource types and identifying solutions that might not otherwise be found.

E3 is supporting the CPUC IRP proceeding, modeling optimal resource portfolios to meet different GHG emission targets for three planning scenarios, including a "Default System Plan." Preliminary results for the CPUC IRP proceeding using E3's RESOLVE model were presented at a workshop on July 27, 2017.[13] E3 incorporated the starting assumptions for the Default System Plan to model the potential of AES in integrated resource planning.

4.4.2 Advanced Energy Storage in RESOLVE Integrated Resource Planning Model

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.

13 Available at: http://www.cpuc.ca.gov/irp/prelimresults2017/

RESOLVE has a particular strength in evaluating flexibility costs. Flexibility costs are driven by the increase in renewable resources and the policy directives for renewable energy targets. 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.[14] 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 in excess of 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 can be conceptualized as 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.

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 said incremental resource can be thought of as the incremental resource's value. 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 2016 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.

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 for round-trip efficiency was created by observing the aggregate round-trip efficiency of all the AES projects in our sample, which amounted to a 78.1% round-trip efficiency. The discharge potential of the 95.5 MW (*inverter* capacity) of non-residential AES projects were assumed to have a one-hour duration.

4.4.3 Hourly Marginal Costs in 2018 vs. 2030

The average daily load and marginal cost to provide energy for 2018 and 2030 are shown in Figure 4-19 and Figure 4-20 respectively.

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[14] 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

FIGURE 4-19: BASE CASE AVERAGE HOURLY GROSS LOAD (MW) AND MARGINAL COST ($/MWH), 2018

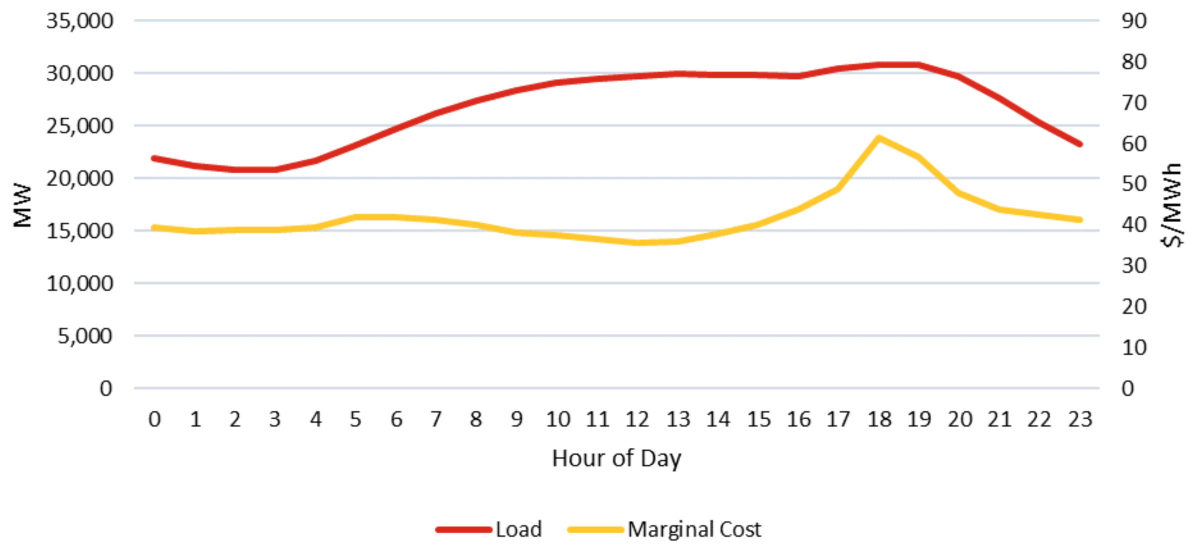
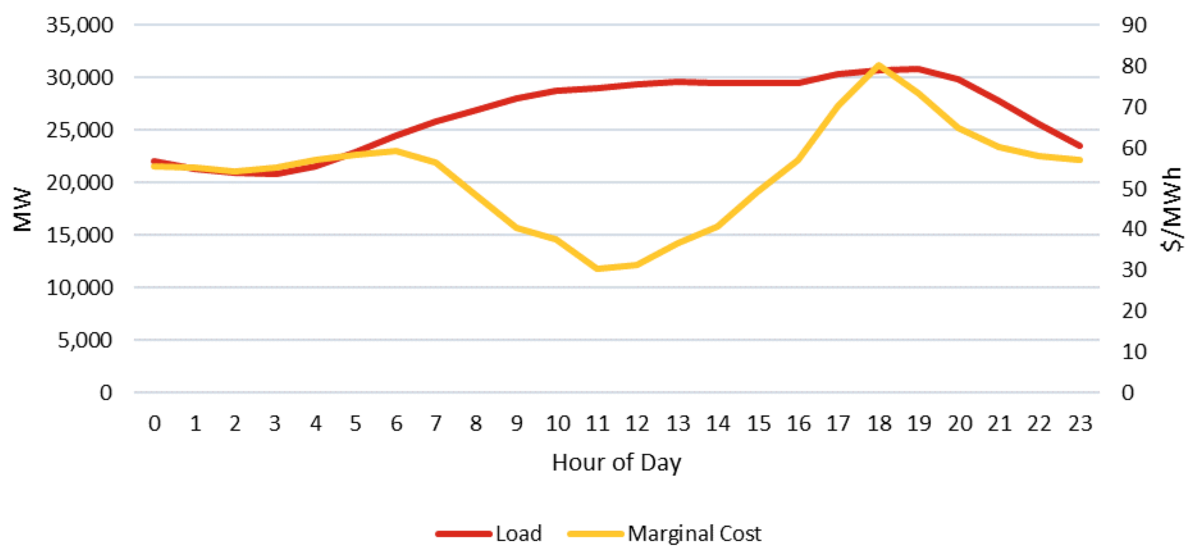


FIGURE 4-20: BASE CASE AVERAGE HOURLY GROSS LOAD (MW) AND MARGINAL COSTS (MWH), 2030



While we see a relatively small difference in the gross load profile between the two years, we see a dramatic difference in the shape of the marginal cost of energy between 2018 and 2030. This change is predominantly the result of deeper penetration of utility-scale solar generation to meet increasingly stringent RPS demands, in combination with higher adoption levels of rooftop 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.

The avoided cost approach described in the previous sections assumes that energy storage reduces costs on the margin, but that the resource portfolio and underlying grid operations are unchanged. Energy storage has even greater value as a flexible resource that reduces capital investments and variable operating costs as California transitions to a high renewable, low carbon electric grid. Energy storage can store excess renewable generation that would otherwise be curtailed, reducing the amount of renewable generation capacity required to achieve a given RPS or carbon target. Energy storage can also potentially serve to reduce morning and evening ramps, reducing the amount of flexible fossil fuel generation required for load balancing and reserves.

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: AES as Load Modifier

Under this use case, the system-level electricity demand is modified to reflect the incremental impact of SGIP AES projects operating in 2016. To implement this use case, the non-residential projects in our sample were aggregated to provide an 8760-hour profile of AES load (which is negative when storage is discharging in aggregate). This load profile was then scaled up to reflect the 95.5 MW of non-residential storage *inverter* capacity in the AES population by the end of 2016. 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 2016 AES dispatching into the future: if pricing signals provided to AES projects remained as they were in 2016 between now and 2030, and thus the optimized dispatching behavior went similarly unchanged, then we would expect the renewable integration value resulting from this use case.

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

To approximate a mid-value case, a use case was constructed that assumes AES will be dispatched in a moderately flexible manner: for utility grid benefit, but without the ability to provide reserves. In addition to merely generating energy, system-level resources must also be operated to provided reserves, in the case of sudden outages, congestion, or changes in electricity demand. These come in the form of frequency response, load following, spinning and non-spinning reserves. While the predominant value of energy storage comes from its ability to shift load from the more expensive evening peak to the mid-day, when renewable curtailment takes place, previous RESOLVE analyses have also shown an appreciable amount of value in resources capable of providing reserves. This phenomenon was observed and discussed in detail during E3's study with Lawrence Berkeley National Lab (LBNL) for the CPUC[15] on the potential value of advanced demand response resources, specifically the "Shimmy" resource. In short, by providing contingency reserves, a resource can free up other resources, likely other storage resources, to take on the behavior of shifting load from expensive hours to cheaper hours. To create this mid-value case, we assume AES can be operated flexibly from a load-shifting perspective, but is not capable of providing reserves and thus does not realize this additional potential value.

High Value: AES Dispatched to Minimize Utility Cost, Including Reserves

From a system-level perspective, AES is most valuable as a resource when it can be operated to meet system needs, capable of avoiding fixed and operational costs in the form of both serving load and providing reserves. To model this highest-value use case, we simply treated the 1-hour duration 95.5 MW of AES *inverter* capacity as a flexible resource that can be dispatched. 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 be dispatched with perfect foresight and in a manner so as to minimize the *grid's* costs, despite the fact that customers' retail rates or preference for utilizing storage for personal contingencies currently provide barriers to storage actually being dispatched in this manner.

4.4.4 Summary Results

Table 4-9 provides the cumulative savings, in NPV 2016 dollars[16], of the 95.5 MW of AES *inverter* capacity operating in 2016, for each use case.[17] The results are broken out by fixed cost, variable cost, and total cost savings. These results are not directly comparable to the DER Avoided Cost Model approach 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.

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

[16] RESOLVE assumes a 5% discount rate, and puts additional weight on the last year of operation, in this case 2030, as this year represents subsequent years as well.

[17] Recall that the rebated capacity of SGIP is around 49 MW. However, the inverter capacity is double that. Because we are analyzing technical potential, we have elected to model based on technical capability rather than rebated capacity.

TABLE 4-9: CUMULATIVE VALUE OF AES ACROSS RESOLVE USE CASES, NPV 2016$ MILLION, 2018 - 2030

Use Case	Fixed Cost Savings	Variable Cost Savings	Total Cost Savings
Low Value	($0.00)	($0.01)	($0.01)
Mid Value	$0.76	$5.80	$6.56
High Value	$9.63	$9.22	$18.86

As with the DER Avoided Cost Approach, AES dispatch for customer benefit and treated as a load modifier increases total grid costs, though only slightly. In the Mid Value Case, NPV benefits from 2018 to 2030 are $6.6 million, predominately in variable operating cost savings. In the High Value Case with reserves, the NPV value is just under three times the Mid Value Case at $18.86 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. In particular, providing reserves could reduce the fixed capital investment required by utilities to provide sufficient flexibility.

Fixed Cost Savings

The observed impact of AES as it pertains to fixed cost savings is similar across each use case: the only two resources whose builds are affected by AES are lithium ion storage and utility-scale solar. The resources selected by RESOLVE are essentially unchanged in the Low Value case.

Table 4-10 summarizes the differences *in capacity* of lithium ion storage and PV selected by the RESOLVE model for the Low, Mid and High cases relative to the base case.

TABLE 4-10: CHANGE IN TOTAL CAPACITY RESULTING FROM AES, 2018-2030

Use Case	Additional Lithium Ion Battery Build (MW)	Additional Solar Build (MW)
Low Value Case	-0.06	0.01
Mid Value Case	-33.36	14.67
High Value Case	-92.56	-4.98

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 about 77%) 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. This improves the general flexibility of the high RPS grid, reducing curtailment and resulting in a *reduction* in overall solar build.

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.

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.

Re-imagining SGIP's Value Through 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 reimagine the results of different scenarios through another metric, namely curtailment. Across the Base Case and Low, Mid and High Value scenarios, the system-wide loads and thus RPS-compliance obligations are the same: 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 scenario.

TABLE 4-11: AVOIDED CURTAILMENT BY SCENARIO

Use Case	Total Curtailment MWh	Avoided Curtailment MWh, Net of Base Case
Low Value Case	2,287,436	(151)
Mid Value Case	2,302,473	(15,188)
High Value Case	167,804	2,119,481

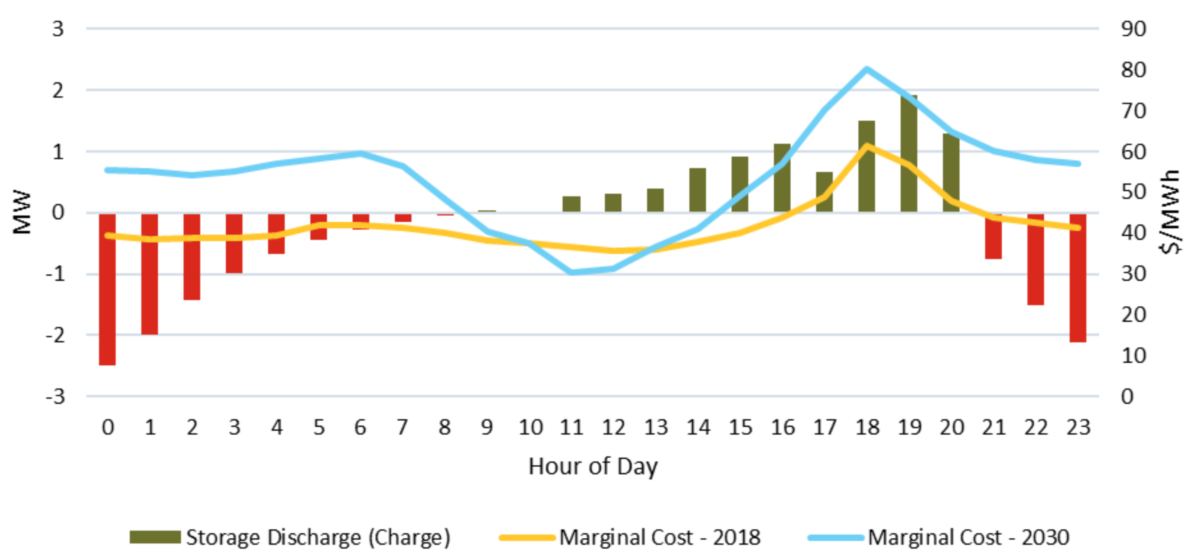
Unsurprisingly, the Low Value Case shows a very small deviation from the Base Case in terms of curtailment, as these two cases are almost identical, with the slight difference being the dispatching of SGIP storage as a load modifier. More striking is the reduction in curtailment between the Base Case and the High Value Case. Curtailment plummets from a total of 2.3 million MWh in the Base Case to only 0.17 million MWh in the High Value Case, a reduction of 93%. 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.

While it may be initially surprising that the Mid Value Case also shows an increase in curtailment relative to the Base Case, this is less surprising when one considers the changes in fixed cost described above. As shown in Table 4-10, the Mid Value Case resulted in an increase in solar capacity, which is synonymous with *increasing* solar overbuild, and thus an increase in curtailment. The High Value Case is the only scenario in which solar build was reduced and, likewise, the only scenario in which we see positive avoided curtailment.

Low Value: AES as Load Modifier

In the lowest overall value use case, in which 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. The modification to gross load modeled in the Low Value Case is shown in Figure 4-21, where it is compared to the 2018 and 2030 marginal energy costs.

FIGURE 4-21: AVERAGE HOURLY STORAGE DISPATCH AS A LOAD MODIFIER COMPARED TO MARGINAL COSTS



Broadly speaking, the modification to system load attributed to AES is well-aligned with the marginal costs of energy in both 2018 and 2030. SGIP systems are observed to discharge starting in the afternoon through the evening peak, and charge at night and through the morning.

SGIP's dispatching aligns slightly more favorably with the 2018 marginal cost shape. 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. While assuming the load modification due to SGIP remains constant from 2018 to 2030 is consistent with analyzing the long-term impact of SGIP *today* on renewable integration, the underlying shape observed in SGIP dispatch is also reflective of 2016 rates. Assuming that rates will change as California's electricity grid evolves, so too will the timing of SGIP charging and discharging. In this sense, we appropriately identify this load modifier scenario as a lower bound for the potential impact of SGIP on renewable integration. Future analysis would be improved by changing the load modification shape over time, rather than holding it constant from 2018 to 2030.

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

In addition to modeling AES as a static load modifier in RESOLVE, we also modeled it in a manner more analogous to front-of-the-meter storage, which is to say that its flexibility as an energy storage resource was available to RESOLVE to minimize costs. Importantly, this means that our mid- and high-value use cases enabled AES dispatch to adjust to changing grid conditions, unlike our load modifier case. Figure 4-22 and Figure 4-23 summarize the observed AES dispatch in the Mid Value Case, in which AES can be utilized to move load, but is not available as a reserve-providing resource.

FIGURE 4-22: AVERAGE HOURLY AES DISPATCH, NO RESERVE CAPABILITY, 2018

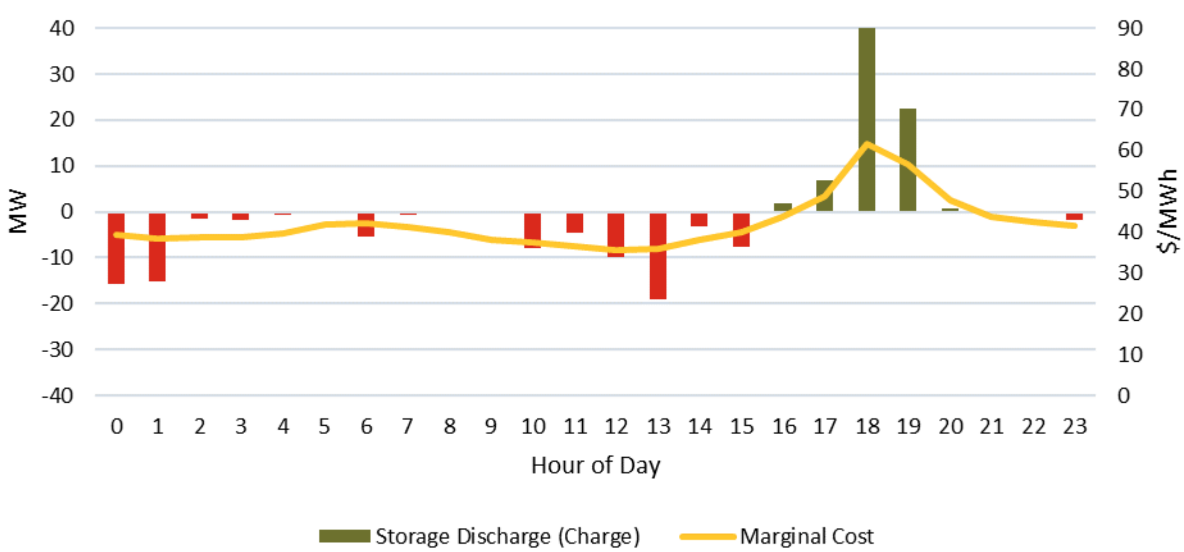
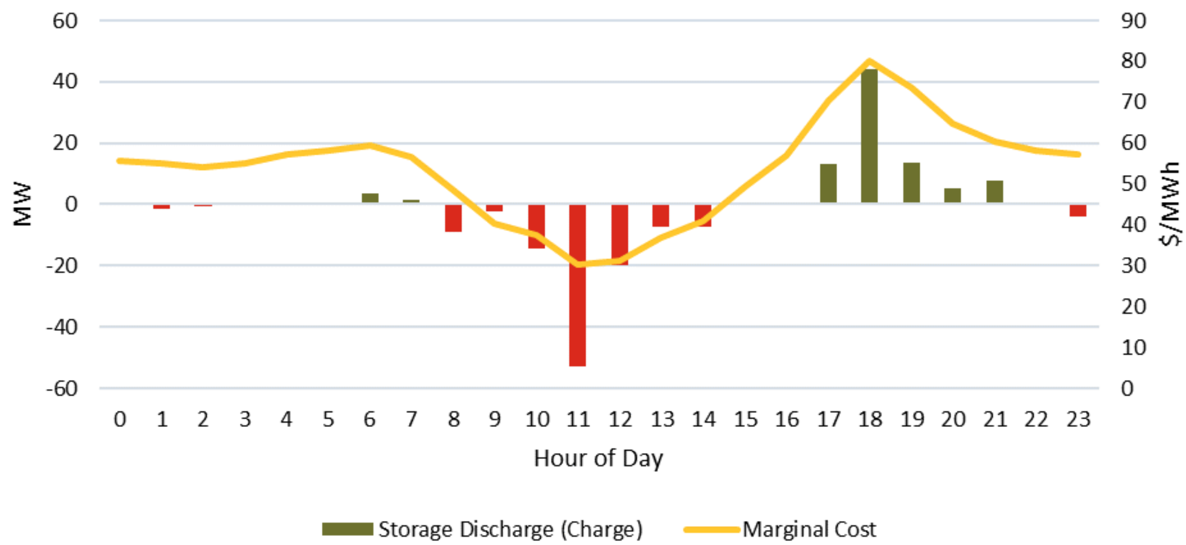


FIGURE 4-23: AVERAGE HOURLY AES DISPATCH, NO RESERVE CAPABILITY, 2030



Unsurprisingly, 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 Case.

High Value: AES Dispatched to Minimize Utility Cost

Figure 4-24 and Figure 4-25 provide the results for the High Value Case.

FIGURE 4-24: AVERAGE HOURLY AES DISPATCH WITH RESERVE CAPABILITY, 2018

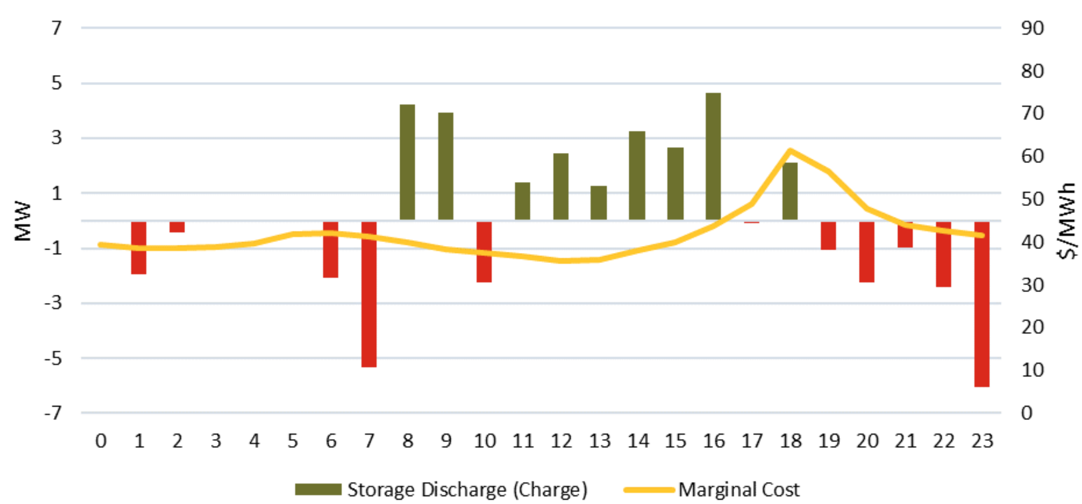
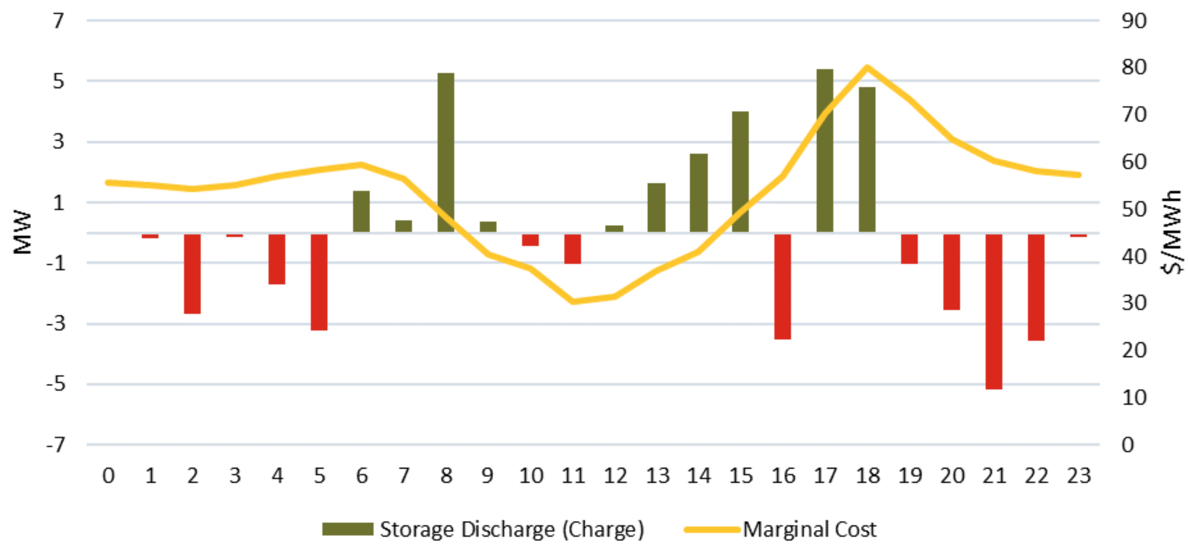


FIGURE 4-25: AVERAGE HOURLY AES DISPATCH WITH RESERVE CAPABILITY, 2030



Curiously, despite the High Value Case showing a larger avoided variable cost than the Mid Value Case, the alignment between marginal energy cost and storage dispatching seems less pronounced in the former. For clarity on this, it is important to consider what behavior is enabled by the ability to provide reserves. Consider Figure 4-26 and Figure 4-27, which include not just storage discharging (charging), but also the MWs of reserve provided by the AES.

FIGURE 4-26: AES PROVIDED RESERVES DISPATCH, 2018

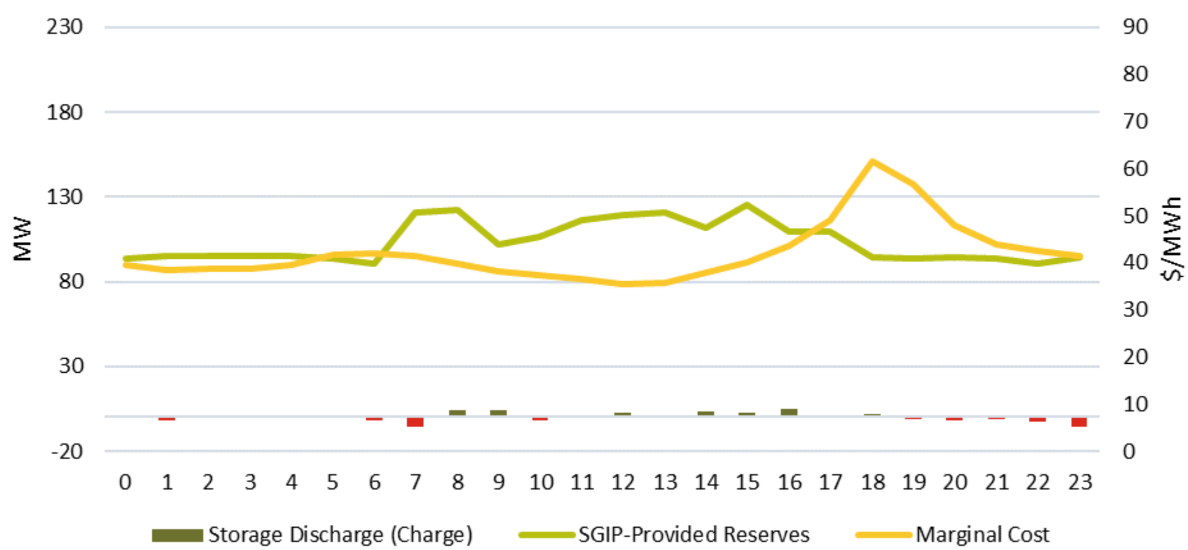
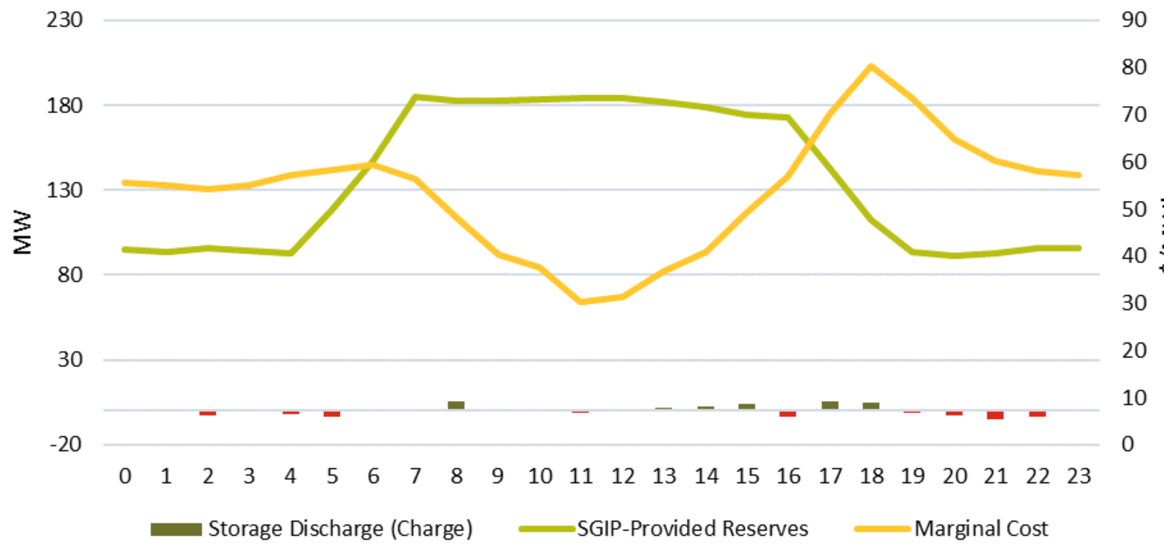


FIGURE 4-27: AES PROVIDED RESERVES DISPATCH, 2030



Two important findings become clear: the magnitude of the capacity devoted to providing reserves far exceeds the amounted devoted to actual discharge (charge); the timing of providing reserves aligns far more closely with hourly marginal costs than the actual dispatching of storage. The former observation suggests that RESOLVE determines that AES is more effectively utilized as a reserve provider than as a flexible load resource. The latter observation confirms that the underlying value being realized by AES still pertains to somehow moving load from the evening and morning hours into the middle of the day.

This behavior is explained when considering what resource would otherwise be providing reserves if not for SGIP AES. The answer is other energy storage, in particular generic lithium ion storage, a generic resource RESOLVE is able to build and dispatch as needed to minimize cost. Because SGIP is capable of providing the mid-day reserves otherwise provided by a generic storage technology, said generic technology is then "freed up" to take on the task of moving load from shoulder hours into the mid-day. One might wonder why a generic lithium ion technology would be seen as preferable to SGIP AES for providing this service. This is due to their relative round-trip efficiencies. Whereas the observed aggregated RTE of SGIP AES was about 77%, generic lithium ion is modeled in RESOLVE as having an 85% RTE. As such, it is preferable for this more efficient resource to move load, and the less efficient resource to provide flexibility/backup.

4.4.5 Interpretation of Incremental Value (Cost)

In considering the value of energy storage, it is intuitive that the "first" MWh of shifted load would be more valuable than the "last" MWh, because while the first MWh would move load from the most expensive hour in the year to the cheapest hour in the year, the spread in hourly costs for the last MWh might not be as dramatic.

Accordingly, a brief point should be made as to the framework within which this analysis was conducted to estimate the incremental value (cost) of AES. In the case of energy storage, evaluating the incremental value of one resource is impacted by where in the loading order the resource falls.

For example, consider the interaction between SGIP AES and storage attributed to the statewide storage mandate under AB 2514. In the above analysis, both the system with AES and the counterfactual without it already included the storage expected from the storage mandate. As such, the “first” MWh of shifted load is attributed to the storage mandate. If, instead, the modeling approach interpreted SGIP as the *next* flexible load resource to be brought onto the system, the estimated marginal value of AES would likely be higher. Ideally, an investigation into the incremental value of AES would try both of these approaches to produce a range of marginal values. This level of detail was outside of the scope of this exercise but would be valuable to further characterize SGIP AES’ value proposition to renewable integration.

To convey the impact of this loading order, E3 conducted a one-off sensitivity analysis, analogous to the High Value RESOLVE Case described above. In this scenario, however, we assumed there to be no storage mandate as part of the future of the California grid. With this assumption, each MWh that SGIP-related storage can shift to cheaper hours is much more valuable. In fact, while our High Value Case approximated SGIP storage to provide $18.8 million in benefits, if we exclude the storage mandate from our input assumptions, we calculate SGIP’s value to be $26.3 million. While we believe the assumptions made in our modeling described above were accurate in that they convey the best approximation for what the future of the California grid will be, this sensitivity analysis conveys the potential impact that the loading order of different resources can have.

APPENDIX A GREEN HOUSE GAS METHODOLOGY

This appendix describes the methodology used to estimate the impacts on greenhouse gas (GHG) emissions from Self-Generation Incentive Program (SGIP) advanced energy storage (AES) projects. The GHG considered in this analysis is carbon dioxide (CO_2), as this is the primary pollutant that is potentially affected by the operation of SGIP AES projects.

A.1 OVERVIEW AND BASELINE DISCUSSION

Hourly GHG impacts are calculated for each SGIP project as the difference between the grid power plant GHG emissions for actual SGIP AES operations 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

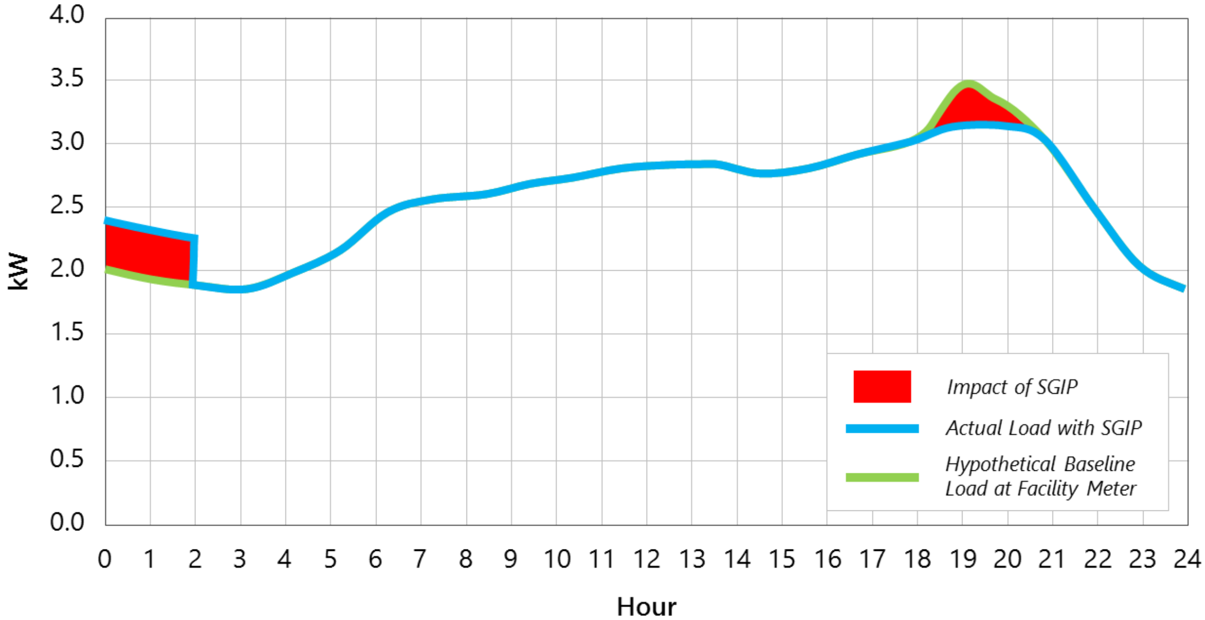
Scenario #1 applies to SGIP AES projects that are installed at facilities absent any additional on-site generation sources such as PV. Table A-1 summarizes the baseline and SGIP conditions in Scenario #1.

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

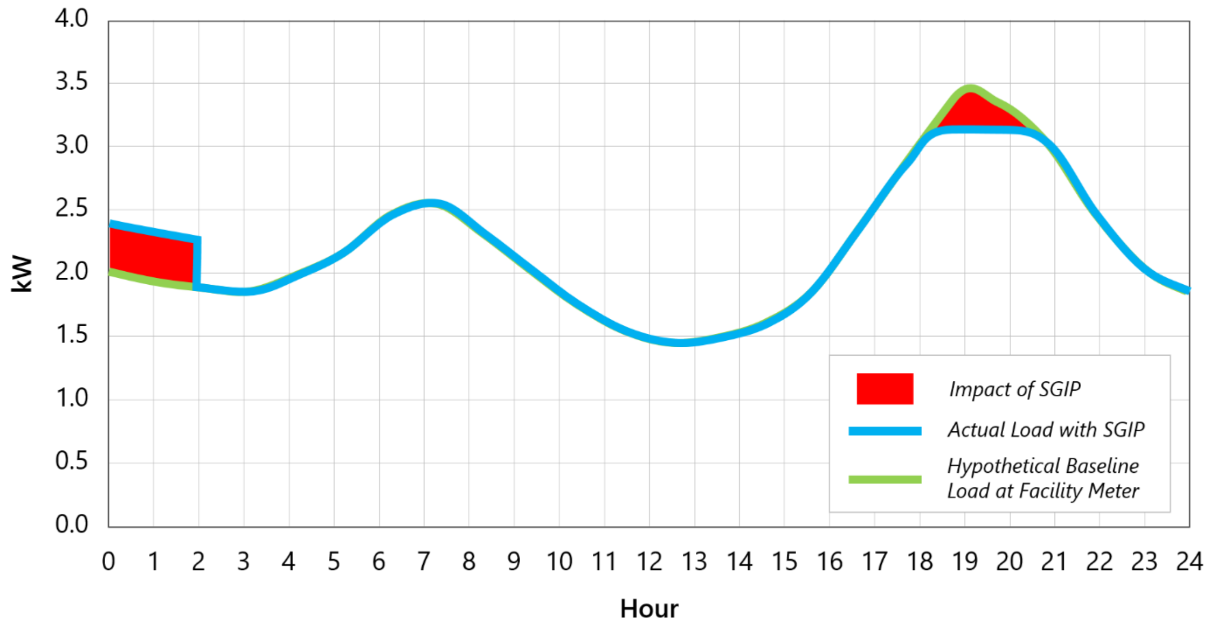
Scenario #2 applies to SGIP AES projects that are installed at facilities paired with on-site PV. The on-site PV in Scenario #2 is not attributed to SGIP meaning that the program did not influence its installation. Table A-2 summarizes the baseline and SGIP conditions in Scenario #2.

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

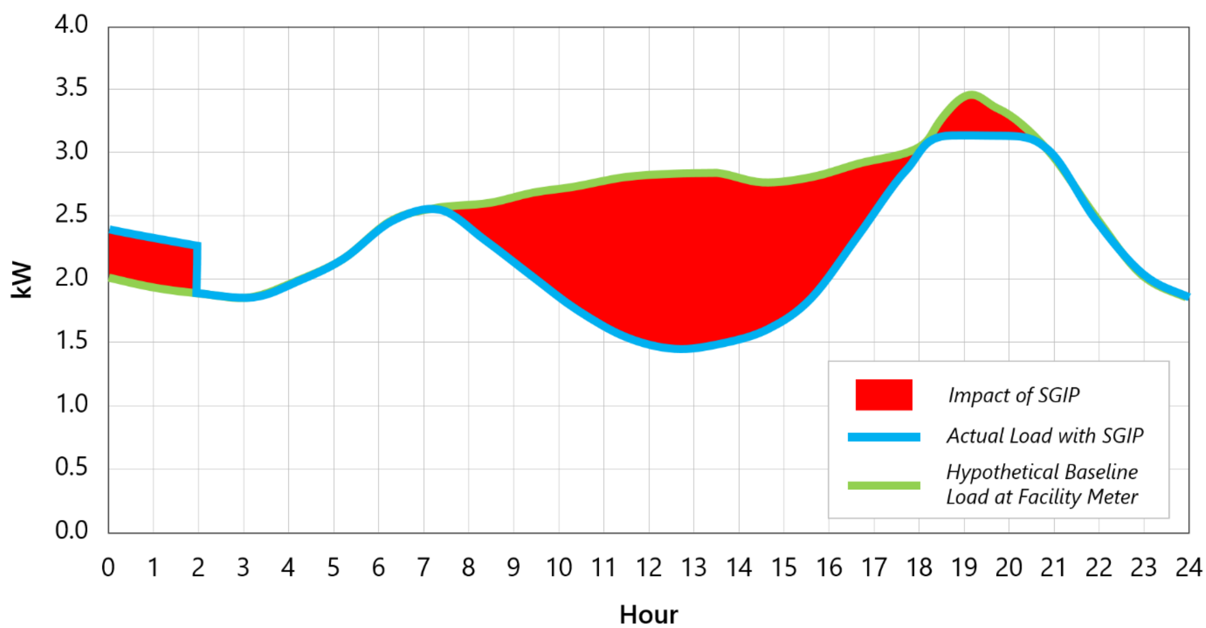
Scenario #3 applies to SGIP AES projects that are installed at facilities paired with on-site PV. The on-site PV in Scenario #3 is attributed to SGIP meaning that the program influenced its installation. Table A-3 summarizes the baseline and SGIP conditions in Scenario #3.

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 (Figure 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

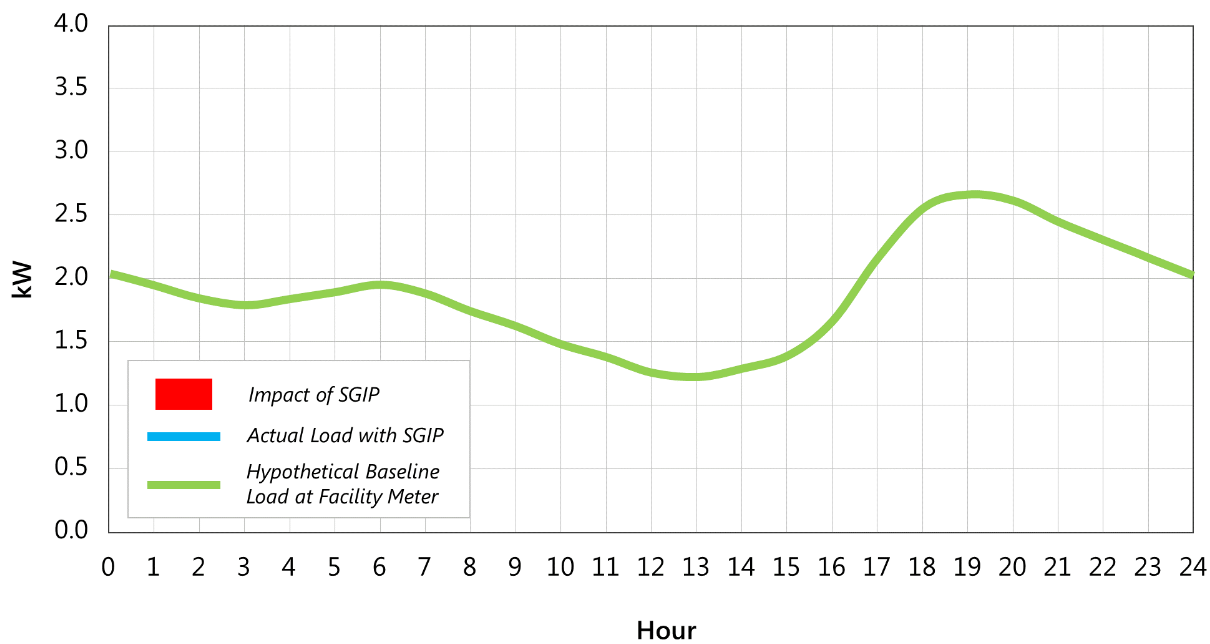


Figure A-5 reflects actual SGIP conditions, where AES is charging from renewables and then discharging in the evening. In the evening, during discharge, grid power levels for the customer are lowered. In the middle of the day, during charging from renewables, grid power levels for the customer are higher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

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

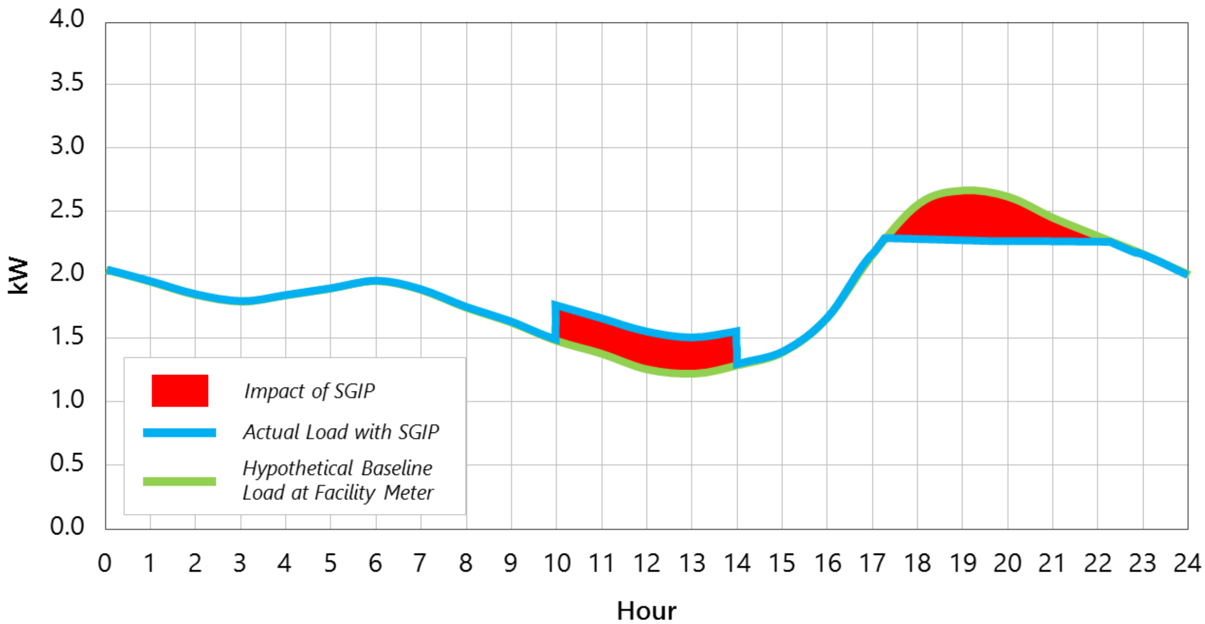
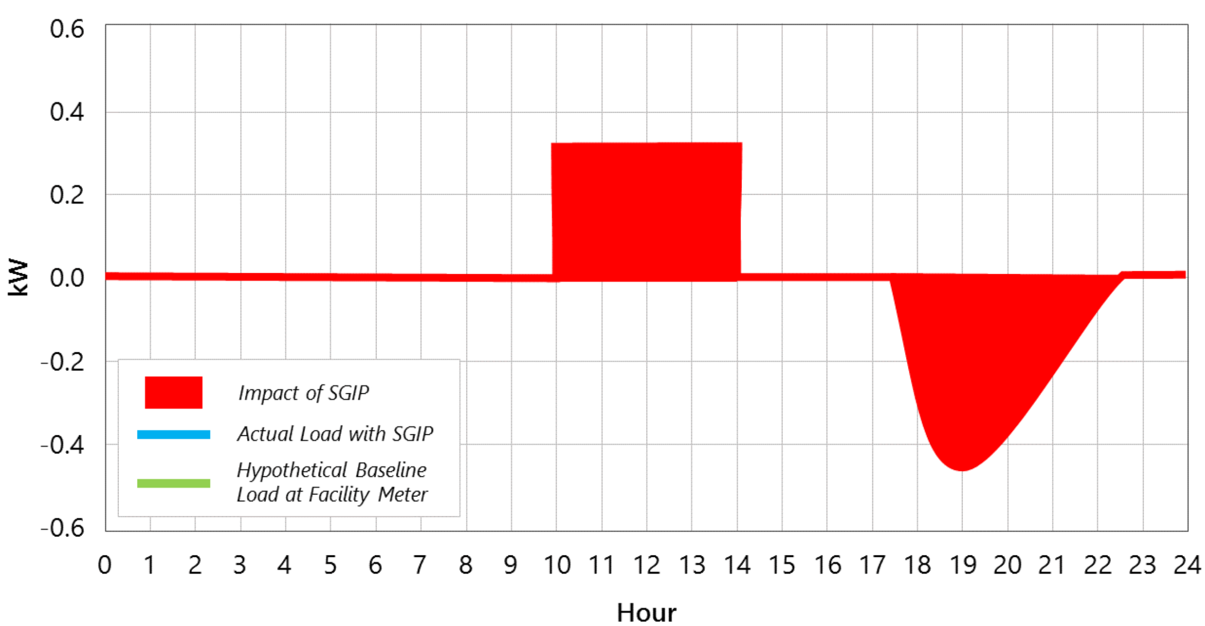


Figure A-6 summarizes the SGIP impact of AES projects in Scenario #2 charging from renewables. Most notably, program impacts are not influenced by PV in any way. PV generation only influences SGIP impacts in Scenario #3 where the SGIP influences the installation of PV.

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:

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

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

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

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:

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

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

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

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.

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

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. 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 hourly emissions rate of the marginal generator is calculated based on the real-time[1] market price curve (with the assumption that the price curve also includes the cost of CO_2):

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

Where:

- MP is the hourly market price of energy (including cap and trade costs)
- VOM is the variable O&M cost for a natural gas plant
- GasPrice is the cost of natural gas delivered to an electric generator

[1] Previous SGIP impact evaluation report have 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.

- 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.[2]

TABLE A-4: BOUNDS ON ELECTRIC SECTOR CARBON EMISSIONS

Baseline	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	11,000	5,500

Additionally, 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. These data were 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 zero tons/MWh was assumed. Otherwise, the market-based approach discussed above was used.

Finally, 5-minute marginal heat rates are averaged to the 15-minute level before merging with 15-minute storage charge/discharge data. Table A-5 summarizes the number and percentage of 15-minute curtailment events observed in 2016 based on the methodology described above.

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2 In previous SGIP impact evaluation reports, the heat rate range for determining marginal emissions was 6,900–12,500 Btu/kWh. For this 2016 impact evaluation, we decreased the lower bound to 5,500 btu/kWh based on recent research of cogeneration unit efficiencies and the fact that gas units may have a lower incremental heat rate at higher outputs. We also decreased the heat rate ceiling to 11,000 btu/kWh. A heat rate above this number either implies a combustion turbine with an extremely low capacity factor, or that high startup costs have been included, which makes energy prices appear higher and therefore inflate the calculated marginal heat rate value.

TABLE A-5: SUMMARY OF 2016 CURTAILMENT EVENTS BY MONTH AND TRADING HUB

2016 Month	NP 15		SP 15	
	15-Minute Curtailment Observations	Percentage of Observations Curtailed	15-Minute Curtailment Observations	Percentage of Observations Curtailed
January	246	8%	245	8%
February	501	18%	501	18%
March	1,023	34%	1,025	34%
April	713	25%	708	25%
May	607	20%	598	20%
June	323	11%	322	11%
July	125	4%	125	4%
August	141	5%	141	5%
September	437	15%	438	15%
October	496	17%	512	17%
November	709	25%	713	25%
December	894	30%	894	30%

A.4 IMPLEMENTATION OF SCENARIOS IN THIS EVALUATION

Due to data quality issues, this evaluation only quantified GHG impacts of non-residential SGIP storage projects. During this evaluation period, most non-residential energy storage projects were installed as standalone projects. Review of inspection reports and interviews with project developers suggest that most other non-residential projects that are co-located with PV are installed at locations where the PV already existed. Energy storage projects installed at locations with pre-existing PV are classified as Scenario #2 (PV not attributed to SGIP). The impact calculation for storage projects in Scenario #2 is the same as for standalone projects. Consequently, all projects in this evaluation were treated as standalone storage projects for impacts calculation purposes. Note that we still consider the influence of charging during PV generation hours as it relates to possible renewable integration benefits, but the customer PV generation itself does not contribute towards SGIP impacts or GHG emission reductions.

APPENDIX B DATA SOURCES AND ESTIMATION APPROACH

This appendix provides an overview of the primary sources of data used to quantify the energy and peak demand impacts of the 2016 Self-Generation Incentive Program (SGIP) and the approach used to estimate program impacts.

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

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
- 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 2016.

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	Non-residential	N	97	97	90	79		
	Non-residential	Y	37	37	34	31	37	33
	Residential	N	134	130	164	148		
	All		**268**	**264**	**288**	**258**	**37**	**33**
SCE	Non-residential	N	82	59	50	39		
	Non-residential	Y	34	31	32	30	34	30
	Residential	N	132	30	125	118		
	All		**248**	**120**	**207**	**187**	**34**	**30**
CSE	Non-residential	N	67	66	64	55		
	Non-residential	Y	12	11	9	9	12	11
	Residential	N	85	83	80	68		
	All		**164**	**160**	**153**	**132**	**12**	**11**
SCG	Non-residential	N	1	1	1	1		
	All		**1**	**1**	**1**	**1**		

B.2 ESTIMATION METHODOLOGY

Metered data available for the sample of non-residential projects were used to estimate population totals for the following 2016 impacts:

- Customer average summer peak demand
- California Independent System Operator (CAISO) system peak demand (top hour and top 200 hours)
- Electric energy
- Greenhouse gas (GHG)

Some data sets for metered projects contained missing data. The cause of these missing data is unknown. Many different possible explanations exist, including temporary metering, communications, or memory failure; or AES operations interruption. In the absence of specific information about the cause of missing data we assumed that missing data were caused by temporary failure of metering and monitoring systems. Consequently, AES performance during these periods was estimated to enable calculation of calendar year totals. Missing performance measurements were imputed at the individual-project level with the average value calculated using non-missing data.

Then, 2016 impacts are calculated for each metered project. The calculation details differ somewhat for the various performance measures, as indicated below, however in each case the result is a single number (Δ_i) per project representing 2016 impacts.

$$\Delta_i = \frac{\sum_{m=1}^{M_S} \Delta b_{Sim}}{M_S}$$ Customer average summertime peak demand impacts Eqn. 1

$$\Delta_i = \Delta iso_i$$ CAISO system peak demand impacts

$$\Delta_i = \frac{\sum_{t=1}^{top\,200} \Delta iso_{it}}{200}$$ Average of demand impacts for top 200 CAISO system load hours

$$\Delta_i = \sum_{t=d}^{366} \Delta kwh_{it}$$ Electric energy impacts

$$\Delta_i = \sum_{t=d}^{366} \Delta ghg_{it}$$ Greenhouse gas impacts

Where:

Δ_i	Impact for metered project *i* during 2016
Δghg_{it}	Greenhouse gas impact for metered project *i* during time period *t*, project online during 2016 from day *d* through the end of the year
Δkwh_{it}	Electric energy impact for metered project *i* during time period *t*, project online during 2016 from day *d* through the end of the year
Δiso_i	Electric demand impact for metered project *i* during the CAISO system load peak hour (July 27, 2016, 4-5 PM PDT)

Δiso_{it} Average electric demand impact for metered project i during the top 200 CAISO system load hours

Δb_{Sim} Billed demand impact for sampled project i in summer month m

M_S Number of months in summer

Information from the metered sample is then summarized with a ratio estimator that is used to translate sample data into an estimate of total population impacts.

$$\hat{R} = \frac{\sum_{i=1}^{n} \Delta_i}{\sum_{i=1}^{n} c_i} \qquad \text{Eqn. 2}$$

Where:

$\hat{R}$ Sample estimate of population ratio of impacts and system capacity

c_i Capacity (kW) of project i in metered sample

Finally, population total annual impacts are estimated:

$$\hat{\Delta} = \hat{R} \times C \qquad \text{Eqn. 3}$$

Where:

$\hat{\Delta}$ Ratio estimate of total annual impacts

C Total capacity (kW) of population

Inter-project variability statistics for the metered sample are used to calculate approximate accuracy of the population estimates. First, the estimated variance for total population impacts is calculated.

$$v\left(\hat{\Delta}\right) = \frac{N^2\left(1-f\right)}{n} \frac{\sum_{i=1}^{n}\left(\Delta_i - \hat{R} \times c_i\right)^2}{\left(n-1\right)} \qquad \text{Eqn. 4}$$

Where:

N Number of projects in population

f Sampling fraction n/N

Next the error in the ratio estimate of population total impacts is calculated.

$$E = t \times \sqrt{v\left(\hat{\Delta}\right)} \qquad \text{Eqn. 5}$$

Where:

t Value from Student's *t* table for *n* and a desired confidence level (90%)

The relative precision associated with the confidence level corresponding to *t* is calculated as:

$$rp = \frac{E}{\hat{\Delta}} \qquad \text{Eqn. 6}$$

B.2.1 Discussion of Accuracy and Possible Sources of Bias

Metered data for a sample of projects were used to estimate total population impacts along with approximate accuracy of those estimates. The metering rate was extremely high for this type of study (~90% of PBI capacity metered, ~73% of non-PBI capacity metered). Consequently, the remaining unmetered portion of the population for which impacts needed to be estimated, and whose impacts estimates were subject to sampling error, was very small. The vendors involved with the majority projects installed through the program provided data for a large proportion of their projects. The sample was, however, a sample of convenience, and thus not entirely random. In the case of projects of vendors providing data, we cannot be certain that the performance of projects for which we received data is entirely representative of the performance of projects whose performance was estimated. Furthermore, no metered data were received for projects installed by several vendors with smaller numbers of completed projects. However, in light of the extremely high metering rate, and also the characteristics of those metered data, it is reasonable to conclude that the available metered data provide a very good indication of the overall performance of SGIP AES projects.

APPENDIX C ADDITIONAL FIGURES AND TABLES

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

FIGURE C-1: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI HOTEL PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.141	0.080	0.040	0.024	0.050	0.080	0.064	0.052	0.050	0.037	0.035	0.063
1	0.112	0.082	0.102	0.060	0.056	0.120	0.031	0.041	0.035	0.034	0.071	0.049
2	0.135	0.071	0.062	0.058	0.058	0.076	0.037	0.058	0.057	0.022	0.030	0.040
3	0.061	0.063	0.044	0.017	0.040	0.047	0.035	0.047	0.048	0.012	0.024	0.041
4	0.037	0.028	0.030	0.039	0.037	0.043	0.025	0.040	0.039	0.020	0.026	0.052
5	0.037	0.042	0.033	0.040	0.038	0.053	0.043	0.026	0.043	0.031	0.036	0.063
6	0.050	0.057	0.043	0.051	0.063	0.069	0.074	0.064	0.030	0.039	0.052	0.063
7	0.056	0.074	0.059	0.078	0.071	0.097	0.100	0.087	0.091	0.072	0.060	0.070
8	0.085	0.063	0.063	0.074	0.079	0.105	0.091	0.064	0.069	0.062	0.063	0.075
9	0.091	0.080	0.062	0.081	0.079	0.103	0.090	0.071	0.072	0.072	0.068	0.067
10	0.074	0.072	0.063	0.072	0.074	0.129	0.101	0.072	0.096	0.077	0.064	0.057
11	0.055	0.067	0.075	0.067	0.084	0.130	0.085	0.082	0.125	0.069	0.056	0.043
12	0.060	0.069	0.056	0.069	0.087	0.111	0.076	0.070	0.095	0.062	0.069	0.068
13	0.063	0.080	0.065	0.064	0.077	0.102	0.076	0.065	0.089	0.068	0.063	0.033
14	0.061	0.092	0.068	0.077	0.085	0.105	0.081	0.086	0.100	0.074	0.064	0.032
15	0.048	0.070	0.057	0.089	0.098	0.106	0.110	0.132	0.105	0.091	0.062	0.029
16	0.044	0.061	0.068	0.094	0.112	0.110	0.127	0.091	0.118	0.073	0.067	0.050
17	0.085	0.082	0.050	0.082	0.076	0.088	0.093	0.077	0.091	0.057	0.096	0.077
18	0.096	0.107	0.094	0.100	0.067	0.076	0.066	0.058	0.094	0.085	0.111	0.099
19	0.094	0.099	0.114	0.117	0.102	0.098	0.074	0.087	0.092	0.087	0.104	0.096
20	0.090	0.091	0.092	0.086	0.100	0.092	0.083	0.066	0.064	0.061	0.089	0.084
21	0.057	0.050	0.046	0.045	0.053	0.050	0.048	0.034	0.037	0.029	0.051	0.060
22	0.049	0.038	0.037	0.033	0.031	0.059	0.041	0.022	0.024	0.020	0.038	0.064
23	0.030	0.033	0.044	0.068	0.060	0.098	0.097	0.086	0.081	0.028	0.027	0.047

FIGURE C-2: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI HOTEL PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.035	-0.040	-0.043	-0.037	-0.042	-0.044	-0.030	-0.028	-0.030	-0.026	-0.040	-0.045
1	-0.031	-0.029	-0.026	-0.028	-0.028	-0.030	-0.023	-0.023	-0.025	-0.023	-0.028	-0.036
2	-0.028	-0.023	-0.020	-0.021	-0.022	-0.022	-0.020	-0.019	-0.020	-0.019	-0.022	-0.028
3	-0.022	-0.018	-0.018	-0.018	-0.020	-0.019	-0.018	-0.018	-0.018	-0.016	-0.020	-0.023
4	-0.019	-0.016	-0.016	-0.017	-0.017	-0.018	-0.017	-0.017	-0.017	-0.015	-0.017	-0.019
5	-0.017	-0.015	-0.016	-0.017	-0.018	-0.019	-0.017	-0.018	-0.017	-0.016	-0.016	-0.018
6	-0.017	-0.016	-0.018	-0.017	-0.018	-0.019	-0.017	-0.017	-0.017	-0.016	-0.017	-0.019
7	-0.024	-0.021	-0.019	-0.018	-0.018	-0.019	-0.016	-0.017	-0.019	-0.017	-0.020	-0.027
8	-0.019	-0.017	-0.015	-0.014	-0.015	-0.016	-0.012	-0.013	-0.015	-0.014	-0.017	-0.026
9	-0.026	-0.021	-0.024	-0.020	-0.027	-0.028	-0.024	-0.022	-0.022	-0.019	-0.026	-0.034
10	-0.028	-0.022	-0.024	-0.024	-0.028	-0.030	-0.027	-0.023	-0.022	-0.020	-0.026	-0.033
11	-0.029	-0.023	-0.023	-0.022	-0.030	-0.032	-0.029	-0.026	-0.027	-0.020	-0.024	-0.028
12	-0.026	-0.022	-0.024	-0.022	-0.027	-0.033	-0.028	-0.025	-0.028	-0.021	-0.023	-0.026
13	-0.022	-0.020	-0.022	-0.023	-0.028	-0.035	-0.029	-0.027	-0.028	-0.022	-0.022	-0.021
14	-0.020	-0.021	-0.024	-0.023	-0.028	-0.038	-0.032	-0.028	-0.028	-0.024	-0.024	-0.019
15	-0.021	-0.024	-0.025	-0.022	-0.030	-0.037	-0.033	-0.033	-0.034	-0.028	-0.027	-0.018
16	-0.020	-0.031	-0.027	-0.025	-0.033	-0.043	-0.035	-0.056	-0.041	-0.037	-0.031	-0.019
17	-0.018	-0.029	-0.026	-0.036	-0.057	-0.073	-0.061	-0.060	-0.068	-0.037	-0.029	-0.018
18	-0.025	-0.032	-0.026	-0.037	-0.051	-0.077	-0.065	-0.046	-0.045	-0.030	-0.037	-0.026
19	-0.032	-0.039	-0.039	-0.037	-0.038	-0.062	-0.050	-0.034	-0.043	-0.031	-0.041	-0.027
20	-0.046	-0.048	-0.044	-0.043	-0.049	-0.059	-0.046	-0.042	-0.050	-0.041	-0.048	-0.036
21	-0.040	-0.042	-0.043	-0.043	-0.054	-0.053	-0.043	-0.035	-0.042	-0.035	-0.043	-0.033
22	-0.058	-0.062	-0.073	-0.064	-0.078	-0.077	-0.064	-0.049	-0.056	-0.045	-0.065	-0.050
23	-0.051	-0.054	-0.061	-0.052	-0.061	-0.062	-0.045	-0.039	-0.043	-0.035	-0.060	-0.051

FIGURE C-3: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI INDUSTRIAL PROJECTS

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
0	0.004	0.005	0.001	0.004	0.008	0.001	0.001	0.001	0.010	0.010	0.006	0.004
1	0.004	0.005	0.002	0.005	0.012	0.002	0.001	0.001	0.009	0.010	0.005	0.001
2	0.003	0.007	0.003	0.003	0.005	0.002	0.001	0.001	0.005	0.010	0.006	0.001
3	0.002	0.005	0.002	0.004	0.004	0.002	0.001	0.002	0.006	0.011	0.004	0.001
4	0.005	0.005	0.002	0.006	0.006	0.006	0.003	0.002	0.009	0.011	0.006	0.001
5	0.004	0.009	0.006	0.009	0.007	0.007	0.004	0.003	0.011	0.012	0.007	0.005
6	0.007	0.009	0.010	0.014	0.011	0.011	0.006	0.005	0.013	0.016	0.009	0.013
7	0.008	0.013	0.021	0.030	0.019	0.024	0.018	0.016	0.018	0.020	0.015	0.011
8	0.007	0.010	0.014	0.033	0.019	0.023	0.018	0.013	0.020	0.022	0.018	0.017
9	0.015	0.029	0.022	0.049	0.028	0.036	0.029	0.023	0.027	0.036	0.041	0.047
10	0.021	0.032	0.022	0.043	0.036	0.040	0.034	0.027	0.026	0.035	0.045	0.048
11	0.027	0.028	0.027	0.037	0.070	0.100	0.079	0.061	0.065	0.069	0.047	0.053
12	0.042	0.027	0.029	0.034	0.073	0.106	0.083	0.069	0.066	0.074	0.041	0.036
13	0.040	0.022	0.026	0.036	0.076	0.096	0.089	0.076	0.064	0.080	0.040	0.045
14	0.034	0.023	0.029	0.036	0.140	0.168	0.148	0.169	0.127	0.092	0.043	0.033
15	0.038	0.030	0.036	0.036	0.166	0.200	0.179	0.196	0.152	0.095	0.036	0.035
16	0.040	0.033	0.054	0.073	0.197	0.222	0.210	0.214	0.172	0.122	0.044	0.047
17	0.061	0.057	0.122	0.176	0.099	0.069	0.085	0.082	0.066	0.122	0.095	0.096
18	0.109	0.098	0.210	0.288	0.154	0.163	0.171	0.165	0.163	0.234	0.157	0.145
19	0.156	0.169	0.249	0.314	0.176	0.188	0.184	0.180	0.192	0.226	0.210	0.202
20	0.174	0.190	0.199	0.196	0.142	0.159	0.153	0.142	0.139	0.162	0.201	0.197
21	0.072	0.085	0.048	0.014	0.015	0.015	0.020	0.028	0.015	0.014	0.093	0.097
22	0.017	0.012	0.035	0.058	0.054	0.046	0.054	0.049	0.055	0.058	0.036	0.027
23	0.058	0.048	0.026	0.006	0.009	0.002	0.002	0.002	0.007	0.010	0.060	0.082

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

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	-0.187	-0.201	-0.234	-0.232	-0.233	-0.277	-0.280	-0.268	-0.245	-0.245	-0.257	-0.272
1	-0.162	-0.162	-0.172	-0.148	-0.147	-0.197	-0.184	-0.184	-0.160	-0.143	-0.221	-0.236
2	-0.115	-0.120	-0.113	-0.098	-0.123	-0.132	-0.101	-0.105	-0.098	-0.087	-0.156	-0.175
3	-0.074	-0.079	-0.076	-0.072	-0.097	-0.090	-0.057	-0.055	-0.060	-0.056	-0.098	-0.121
4	-0.058	-0.061	-0.057	-0.055	-0.073	-0.065	-0.042	-0.031	-0.036	-0.032	-0.059	-0.073
5	-0.046	-0.042	-0.044	-0.045	-0.056	-0.044	-0.031	-0.024	-0.024	-0.031	-0.047	-0.052
6	-0.035	-0.029	-0.034	-0.040	-0.042	-0.026	-0.025	-0.019	-0.019	-0.027	-0.033	-0.033
7	-0.025	-0.024	-0.023	-0.027	-0.023	-0.023	-0.021	-0.012	-0.019	-0.019	-0.024	-0.024
8	-0.017	-0.012	-0.011	-0.013	-0.010	-0.011	-0.011	-0.010	-0.009	-0.012	-0.020	-0.019
9	-0.026	-0.015	-0.019	-0.020	-0.016	-0.012	-0.012	-0.012	-0.012	-0.017	-0.031	-0.031
10	-0.026	-0.019	-0.019	-0.021	-0.017	-0.027	-0.017	-0.016	-0.022	-0.024	-0.029	-0.031
11	-0.029	-0.022	-0.014	-0.019	-0.009	-0.006	-0.009	-0.014	-0.013	-0.020	-0.026	-0.023
12	-0.012	-0.016	-0.014	-0.017	-0.012	-0.011	-0.007	-0.009	-0.013	-0.022	-0.019	-0.018
13	-0.014	-0.017	-0.013	-0.015	-0.009	-0.014	-0.008	-0.011	-0.010	-0.019	-0.015	-0.016
14	-0.025	-0.012	-0.010	-0.014	-0.015	-0.033	-0.031	-0.019	-0.021	-0.033	-0.017	-0.014
15	-0.024	-0.012	-0.009	-0.010	-0.013	-0.033	-0.028	-0.018	-0.018	-0.028	-0.020	-0.012
16	-0.026	-0.010	-0.008	-0.011	-0.011	-0.015	-0.013	-0.013	-0.016	-0.022	-0.012	-0.014
17	-0.019	-0.008	-0.008	-0.013	-0.011	-0.022	-0.023	-0.026	-0.033	-0.027	-0.012	-0.013
18	-0.015	-0.012	-0.011	-0.013	-0.010	-0.010	-0.008	-0.013	-0.021	-0.018	-0.016	-0.015
19	-0.013	-0.014	-0.010	-0.012	-0.011	-0.010	-0.006	-0.009	-0.017	-0.017	-0.018	-0.017
20	-0.017	-0.008	-0.038	-0.081	-0.074	-0.066	-0.056	-0.066	-0.060	-0.069	-0.022	-0.017
21	-0.017	-0.021	-0.098	-0.187	-0.191	-0.181	-0.184	-0.175	-0.168	-0.199	-0.046	-0.030
22	-0.137	-0.173	-0.193	-0.230	-0.232	-0.263	-0.247	-0.255	-0.225	-0.235	-0.186	-0.214
23	-0.075	-0.120	-0.212	-0.312	-0.314	-0.355	-0.362	-0.344	-0.303	-0.316	-0.164	-0.150

FIGURE C-5: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI SCHOOL PROJECTS

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	0.000	0.000	0.000	0.000	0.001	0.001	0.002	0.000	0.001	0.002	0.001	0.001
1	0.000	0.000	0.000	0.000	0.001	0.002	0.003	0.001	0.002	0.002	0.002	0.002
2	0.000	0.000	0.000	0.000	0.001	0.003	0.004	0.001	0.002	0.002	0.001	0.000
3	0.000	0.000	0.000	0.000	0.003	0.006	0.003	0.001	0.001	0.002	0.001	0.000
4	0.000	0.000	0.000	0.001	0.002	0.003	0.003	0.000	0.001	0.003	0.001	0.001
5	0.000	0.000	0.000	0.000	0.005	0.003	0.003	0.001	0.002	0.003	0.002	0.002
6	0.000	0.000	0.000	0.000	0.011	0.003	0.006	0.005	0.003	0.005	0.016	0.008
7	0.000	0.000	0.000	0.000	0.026	0.009	0.009	0.011	0.007	0.008	0.030	0.017
8	0.000	0.000	0.000	0.001	0.039	0.017	0.015	0.016	0.014	0.012	0.066	0.054
9	0.000	0.000	0.000	0.006	0.042	0.017	0.024	0.027	0.024	0.017	0.102	0.091
10	0.000	0.000	0.000	0.030	0.037	0.024	0.048	0.049	0.042	0.022	0.106	0.090
11	0.000	0.000	0.000	0.001	0.068	0.039	0.059	0.080	0.104	0.114	0.102	0.090
12	0.000	0.000	0.000	0.000	0.132	0.062	0.083	0.113	0.124	0.126	0.062	0.053
13	0.000	0.000	0.000	0.007	0.145	0.122	0.123	0.158	0.180	0.135	0.045	0.030
14	0.000	0.000	0.000	0.013	0.112	0.239	0.190	0.184	0.227	0.135	0.062	0.040
15	0.000	0.000	0.000	0.019	0.095	0.200	0.168	0.202	0.200	0.096	0.074	0.053
16	0.000	0.000	0.000	0.016	0.089	0.182	0.177	0.208	0.178	0.107	0.083	0.060
17	0.000	0.000	0.000	0.016	0.086	0.053	0.056	0.052	0.039	0.142	0.095	0.076
18	0.000	0.000	0.000	0.016	0.101	0.062	0.060	0.061	0.047	0.146	0.120	0.100
19	0.000	0.000	0.000	0.018	0.128	0.066	0.060	0.067	0.057	0.123	0.120	0.114
20	0.000	0.000	0.000	0.015	0.078	0.069	0.056	0.058	0.054	0.064	0.102	0.123
21	0.000	0.000	0.000	0.010	0.027	0.058	0.047	0.039	0.040	0.021	0.052	0.063
22	0.000	0.000	0.000	0.008	0.041	0.029	0.037	0.025	0.023	0.032	0.023	0.022
23	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.027	0.029

FIGURE C-6: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI SCHOOL PROJECTS

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	0.000	0.000	0.000	-0.051	-0.235	-0.322	-0.315	-0.346	-0.366	-0.276	-0.297	-0.240
1	0.000	0.000	0.000	-0.051	-0.205	-0.233	-0.271	-0.254	-0.251	-0.167	-0.262	-0.221
2	0.000	0.000	0.000	-0.042	-0.181	-0.128	-0.111	-0.101	-0.108	-0.119	-0.156	-0.127
3	0.000	0.000	0.000	-0.026	-0.131	-0.075	-0.063	-0.049	-0.064	-0.090	-0.107	-0.098
4	0.000	0.000	0.000	-0.007	-0.091	-0.050	-0.059	-0.041	-0.031	-0.055	-0.069	-0.071
5	0.000	0.000	0.000	0.000	-0.046	-0.038	-0.046	-0.029	-0.009	-0.031	-0.051	-0.047
6	0.000	0.000	0.000	0.000	-0.022	-0.019	-0.029	-0.017	-0.004	-0.017	-0.028	-0.026
7	0.000	0.000	0.000	-0.003	-0.009	-0.006	-0.017	-0.012	-0.003	-0.006	-0.010	-0.017
8	0.000	0.000	0.000	-0.005	-0.003	-0.004	-0.012	-0.009	-0.003	-0.004	-0.009	-0.012
9	0.000	0.000	0.000	-0.004	-0.003	-0.004	-0.010	-0.010	-0.011	-0.016	-0.014	-0.018
10	0.000	0.000	0.000	-0.010	-0.002	-0.004	-0.006	-0.006	-0.015	-0.020	-0.029	-0.026
11	0.000	0.000	0.000	-0.006	-0.001	-0.002	-0.006	-0.003	-0.010	-0.019	-0.027	-0.022
12	0.000	0.000	0.000	-0.002	-0.003	-0.003	-0.005	-0.003	-0.010	-0.018	-0.025	-0.020
13	0.000	0.000	0.000	-0.002	-0.004	-0.003	-0.005	-0.004	-0.009	-0.014	-0.022	-0.019
14	0.000	0.000	0.000	0.000	-0.003	-0.001	-0.005	-0.004	-0.003	-0.003	-0.013	-0.009
15	0.000	0.000	0.000	-0.001	-0.005	-0.004	-0.005	-0.004	-0.006	-0.004	-0.006	-0.005
16	0.000	0.000	0.000	0.000	-0.007	-0.003	-0.005	-0.005	-0.004	-0.003	-0.004	-0.006
17	0.000	0.000	0.000	0.000	-0.015	-0.011	-0.015	-0.032	-0.014	-0.003	-0.002	-0.004
18	0.000	0.000	0.000	0.000	-0.016	-0.005	-0.013	-0.011	-0.006	-0.003	-0.001	-0.005
19	0.000	0.000	0.000	0.000	-0.005	-0.002	-0.009	-0.004	-0.002	-0.004	-0.002	-0.003
20	0.000	0.000	0.000	0.000	-0.034	-0.007	-0.012	-0.009	-0.024	-0.073	-0.013	-0.004
21	0.000	0.000	0.000	0.000	-0.166	-0.098	-0.074	-0.121	-0.129	-0.218	-0.089	-0.062
22	0.000	0.000	0.000	0.000	-0.117	-0.228	-0.187	-0.249	-0.235	-0.186	-0.196	-0.165
23	0.000	0.000	0.000	-0.049	-0.286	-0.371	-0.315	-0.377	-0.372	-0.315	-0.182	-0.143

FIGURE C-7: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI RETAIL PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.014	0.004	0.002	0.011	0.009	0.006	0.004	0.004	0.001	0.005	0.002	0.009
1	0.002	0.005	0.007	0.001	0.008	0.004	0.003	0.003	0.000	0.000	0.006	0.008
2	0.037	0.032	0.003	0.000	0.008	0.003	0.001	0.002	0.000	0.000	0.001	0.006
3	0.033	0.019	0.002	0.001	0.011	0.002	0.003	0.002	0.001	0.000	0.002	0.018
4	0.004	0.002	0.004	0.002	0.025	0.013	0.005	0.008	0.009	0.005	0.002	0.011
5	0.005	0.004	0.009	0.021	0.045	0.017	0.019	0.023	0.032	0.011	0.006	0.013
6	0.055	0.024	0.033	0.025	0.026	0.009	0.012	0.029	0.023	0.007	0.007	0.032
7	0.055	0.028	0.016	0.011	0.026	0.020	0.022	0.038	0.032	0.008	0.006	0.027
8	0.019	0.007	0.006	0.004	0.012	0.020	0.027	0.026	0.015	0.005	0.008	0.010
9	0.017	0.010	0.039	0.041	0.028	0.042	0.047	0.033	0.032	0.034	0.023	0.012
10	0.026	0.038	0.057	0.053	0.064	0.077	0.067	0.072	0.074	0.043	0.058	0.011
11	0.037	0.073	0.054	0.048	0.044	0.075	0.073	0.057	0.075	0.051	0.072	0.015
12	0.050	0.063	0.054	0.048	0.054	0.060	0.082	0.064	0.067	0.055	0.069	0.022
13	0.043	0.073	0.052	0.054	0.066	0.061	0.065	0.056	0.057	0.059	0.075	0.029
14	0.042	0.065	0.051	0.047	0.063	0.065	0.057	0.056	0.057	0.046	0.071	0.029
15	0.035	0.058	0.046	0.041	0.052	0.055	0.044	0.053	0.042	0.038	0.061	0.034
16	0.041	0.055	0.061	0.089	0.035	0.049	0.053	0.052	0.039	0.034	0.074	0.066
17	0.113	0.119	0.061	0.058	0.026	0.039	0.052	0.060	0.053	0.018	0.106	0.088
18	0.098	0.142	0.134	0.117	0.048	0.081	0.076	0.102	0.078	0.018	0.064	0.057
19	0.078	0.104	0.095	0.126	0.102	0.118	0.115	0.123	0.042	0.009	0.036	0.042
20	0.051	0.062	0.048	0.099	0.092	0.081	0.070	0.072	0.026	0.002	0.009	0.024
21	0.018	0.018	0.010	0.019	0.015	0.015	0.012	0.011	0.004	0.000	0.002	0.006
22	0.008	0.006	0.005	0.006	0.008	0.007	0.003	0.006	0.001	0.000	0.003	0.005
23	0.003	0.001	0.003	0.011	0.009	0.010	0.005	0.006	0.001	0.000	0.002	0.007

FIGURE C-8: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI RETAIL PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.022	-0.023	-0.026	-0.025	-0.023	-0.024	-0.024	-0.026	-0.027	-0.027	-0.031	-0.042
1	-0.020	-0.023	-0.025	-0.028	-0.025	-0.026	-0.026	-0.027	-0.027	-0.026	-0.028	-0.031
2	-0.021	-0.026	-0.025	-0.028	-0.025	-0.027	-0.025	-0.026	-0.027	-0.026	-0.028	-0.029
3	-0.020	-0.023	-0.024	-0.025	-0.025	-0.026	-0.025	-0.026	-0.029	-0.025	-0.028	-0.027
4	-0.038	-0.032	-0.024	-0.025	-0.026	-0.026	-0.024	-0.028	-0.029	-0.025	-0.027	-0.027
5	-0.027	-0.025	-0.024	-0.026	-0.028	-0.025	-0.025	-0.027	-0.032	-0.027	-0.027	-0.026
6	-0.019	-0.022	-0.024	-0.025	-0.025	-0.026	-0.024	-0.028	-0.031	-0.027	-0.026	-0.025
7	-0.018	-0.023	-0.025	-0.025	-0.028	-0.028	-0.029	-0.037	-0.032	-0.025	-0.026	-0.026
8	-0.018	-0.024	-0.023	-0.021	-0.023	-0.023	-0.028	-0.031	-0.026	-0.023	-0.025	-0.026
9	-0.027	-0.029	-0.064	-0.105	-0.080	-0.104	-0.092	-0.093	-0.043	-0.024	-0.028	-0.028
10	-0.132	-0.119	-0.083	-0.092	-0.060	-0.101	-0.078	-0.075	-0.043	-0.026	-0.028	-0.028
11	-0.116	-0.128	-0.064	-0.044	-0.040	-0.047	-0.050	-0.041	-0.037	-0.029	-0.033	-0.026
12	-0.074	-0.087	-0.059	-0.045	-0.043	-0.047	-0.049	-0.039	-0.041	-0.033	-0.035	-0.025
13	-0.043	-0.061	-0.052	-0.039	-0.050	-0.049	-0.053	-0.040	-0.047	-0.035	-0.042	-0.026
14	-0.041	-0.049	-0.054	-0.041	-0.057	-0.047	-0.058	-0.049	-0.042	-0.039	-0.041	-0.026
15	-0.044	-0.058	-0.050	-0.046	-0.061	-0.060	-0.055	-0.045	-0.045	-0.035	-0.050	-0.028
16	-0.036	-0.071	-0.047	-0.048	-0.053	-0.061	-0.058	-0.045	-0.042	-0.039	-0.060	-0.030
17	-0.038	-0.063	-0.064	-0.061	-0.052	-0.065	-0.072	-0.059	-0.053	-0.038	-0.048	-0.029
18	-0.049	-0.077	-0.067	-0.071	-0.046	-0.051	-0.064	-0.052	-0.044	-0.035	-0.056	-0.037
19	-0.047	-0.095	-0.066	-0.088	-0.048	-0.041	-0.054	-0.039	-0.036	-0.035	-0.068	-0.038
20	-0.087	-0.093	-0.046	-0.067	-0.073	-0.065	-0.050	-0.052	-0.051	-0.064	-0.076	-0.046
21	-0.112	-0.106	-0.076	-0.079	-0.061	-0.044	-0.081	-0.065	-0.032	-0.029	-0.061	-0.038
22	-0.030	-0.040	-0.030	-0.047	-0.044	-0.037	-0.040	-0.031	-0.030	-0.026	-0.035	-0.036
23	-0.027	-0.024	-0.026	-0.026	-0.024	-0.030	-0.025	-0.026	-0.028	-0.028	-0.028	-0.034

FIGURE C-9: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI RETAIL PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.001	0.002	0.004	0.001	0.000	0.002	0.001	0.005	0.002	0.001	0.002	0.002
1	0.001	0.002	0.008	0.001	0.000	0.001	0.000	0.001	0.001	0.000	0.001	0.003
2	0.000	0.002	0.007	0.002	0.001	0.002	0.001	0.001	0.002	0.001	0.001	0.001
3	0.002	0.002	0.003	0.002	0.001	0.002	0.002	0.000	0.000	0.001	0.001	0.001
4	0.000	0.002	0.004	0.002	0.002	0.005	0.001	0.001	0.000	0.001	0.001	0.003
5	0.001	0.003	0.009	0.003	0.002	0.002	0.002	0.002	0.001	0.001	0.004	0.003
6	0.001	0.003	0.005	0.003	0.001	0.005	0.006	0.007	0.002	0.002	0.003	0.002
7	0.001	0.002	0.010	0.007	0.004	0.007	0.012	0.014	0.009	0.013	0.009	0.006
8	0.003	0.006	0.011	0.011	0.011	0.009	0.015	0.013	0.012	0.012	0.009	0.006
9	0.009	0.009	0.020	0.015	0.020	0.021	0.016	0.025	0.022	0.032	0.015	0.011
10	0.011	0.010	0.030	0.024	0.030	0.029	0.025	0.027	0.030	0.045	0.017	0.018
11	0.014	0.016	0.030	0.030	0.036	0.022	0.038	0.033	0.033	0.029	0.032	0.018
12	0.023	0.029	0.041	0.042	0.035	0.025	0.041	0.046	0.044	0.038	0.042	0.019
13	0.026	0.032	0.039	0.037	0.039	0.026	0.040	0.069	0.048	0.034	0.030	0.018
14	0.035	0.045	0.028	0.053	0.075	0.184	0.183	0.191	0.055	0.035	0.020	0.013
15	0.075	0.039	0.065	0.061	0.089	0.238	0.216	0.235	0.057	0.035	0.032	0.020
16	0.083	0.076	0.072	0.071	0.094	0.266	0.245	0.287	0.051	0.053	0.046	0.042
17	0.091	0.066	0.121	0.182	0.125	0.038	0.053	0.053	0.132	0.107	0.082	0.068
18	0.118	0.081	0.254	0.318	0.241	0.086	0.106	0.108	0.300	0.271	0.202	0.107
19	0.171	0.130	0.310	0.322	0.292	0.099	0.119	0.119	0.326	0.323	0.311	0.221
20	0.156	0.142	0.206	0.096	0.118	0.077	0.074	0.078	0.221	0.227	0.314	0.279
21	0.057	0.058	0.048	0.013	0.021	0.040	0.054	0.069	0.011	0.008	0.145	0.232
22	0.023	0.019	0.027	0.018	0.015	0.021	0.024	0.019	0.042	0.045	0.003	0.007
23	0.040	0.019	0.008	0.001	0.000	0.005	0.003	0.000	0.002	0.002	0.023	0.073

FIGURE C-10: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI RETAIL PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.347	-0.252	-0.283	-0.255	-0.247	-0.305	-0.302	-0.336	-0.302	-0.242	-0.224	-0.209
1	-0.315	-0.218	-0.248	-0.226	-0.216	-0.204	-0.219	-0.277	-0.261	-0.217	-0.223	-0.204
2	-0.207	-0.138	-0.171	-0.150	-0.140	-0.080	-0.091	-0.104	-0.136	-0.173	-0.218	-0.199
3	-0.046	-0.052	-0.095	-0.097	-0.093	-0.045	-0.059	-0.051	-0.086	-0.131	-0.180	-0.191
4	-0.029	-0.027	-0.073	-0.056	-0.067	-0.033	-0.039	-0.033	-0.055	-0.094	-0.114	-0.150
5	-0.025	-0.020	-0.056	-0.040	-0.050	-0.027	-0.029	-0.025	-0.035	-0.056	-0.063	-0.101
6	-0.020	-0.016	-0.042	-0.030	-0.030	-0.023	-0.024	-0.016	-0.022	-0.034	-0.034	-0.067
7	-0.016	-0.014	-0.019	-0.014	-0.011	-0.016	-0.014	-0.011	-0.011	-0.016	-0.026	-0.039
8	-0.006	-0.007	-0.013	-0.014	-0.010	-0.016	-0.014	-0.010	-0.010	-0.013	-0.020	-0.023
9	-0.004	-0.005	-0.012	-0.016	-0.013	-0.012	-0.014	-0.009	-0.008	-0.012	-0.015	-0.020
10	-0.003	-0.007	-0.013	-0.016	-0.013	-0.020	-0.013	-0.011	-0.010	-0.018	-0.015	-0.022
11	-0.005	-0.008	-0.014	-0.014	-0.018	-0.011	-0.009	-0.009	-0.007	-0.020	-0.012	-0.018
12	-0.004	-0.006	-0.015	-0.022	-0.019	-0.007	-0.007	-0.010	-0.007	-0.014	-0.018	-0.017
13	-0.003	-0.005	-0.018	-0.018	-0.013	-0.012	-0.009	-0.012	-0.012	-0.012	-0.022	-0.018
14	-0.003	-0.005	-0.015	-0.013	-0.007	-0.009	-0.011	-0.013	-0.025	-0.009	-0.013	-0.017
15	-0.005	-0.005	-0.012	-0.013	-0.005	-0.006	-0.013	-0.018	-0.017	-0.008	-0.011	-0.015
16	-0.003	-0.005	-0.010	-0.014	-0.005	-0.006	-0.009	-0.008	-0.007	-0.009	-0.014	-0.014
17	-0.002	-0.005	-0.016	-0.014	-0.008	-0.023	-0.021	-0.016	-0.008	-0.008	-0.018	-0.017
18	-0.005	-0.007	-0.021	-0.015	-0.006	-0.007	-0.008	-0.010	-0.006	-0.008	-0.017	-0.022
19	-0.002	-0.005	-0.017	-0.013	-0.003	-0.006	-0.007	-0.008	-0.005	-0.010	-0.026	-0.023
20	-0.002	-0.004	-0.028	-0.017	-0.016	-0.011	-0.012	-0.014	-0.010	-0.006	-0.035	-0.018
21	-0.007	-0.013	-0.051	-0.062	-0.067	-0.062	-0.065	-0.058	-0.091	-0.063	-0.032	-0.028
22	-0.068	-0.070	-0.121	-0.144	-0.139	-0.219	-0.190	-0.211	-0.157	-0.093	-0.087	-0.070
23	-0.088	-0.124	-0.247	-0.255	-0.254	-0.311	-0.311	-0.327	-0.287	-0.247	-0.156	-0.066

FIGURE C-11: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI OTHER PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.064	0.076	0.043	0.014	0.028	0.058	0.057	0.063	0.070	0.066	0.045	0.052
1	0.027	0.033	0.017	0.001	0.003	0.005	0.001	0.003	0.005	0.004	0.047	0.056
2	0.012	0.016	0.006	0.001	0.006	0.002	0.001	0.003	0.004	0.004	0.001	0.005
3	0.013	0.016	0.013	0.002	0.008	0.004	0.000	0.001	0.004	0.012	0.000	0.005
4	0.023	0.020	0.020	0.007	0.013	0.009	0.011	0.002	0.002	0.010	0.002	0.002
5	0.023	0.013	0.026	0.017	0.018	0.009	0.012	0.015	0.015	0.019	0.013	0.010
6	0.067	0.037	0.039	0.027	0.030	0.031	0.028	0.027	0.021	0.017	0.018	0.021
7	0.075	0.043	0.066	0.041	0.057	0.058	0.050	0.054	0.035	0.034	0.032	0.036
8	0.060	0.051	0.053	0.036	0.048	0.042	0.038	0.034	0.028	0.020	0.031	0.032
9	0.065	0.074	0.051	0.051	0.072	0.068	0.055	0.054	0.064	0.045	0.049	0.030
10	0.079	0.050	0.058	0.061	0.075	0.087	0.070	0.072	0.082	0.058	0.062	0.040
11	0.071	0.059	0.064	0.051	0.077	0.089	0.069	0.068	0.068	0.055	0.065	0.043
12	0.090	0.066	0.071	0.063	0.066	0.086	0.075	0.068	0.068	0.057	0.080	0.050
13	0.093	0.076	0.073	0.061	0.068	0.086	0.071	0.071	0.068	0.058	0.062	0.042
14	0.070	0.076	0.081	0.047	0.055	0.059	0.067	0.072	0.055	0.052	0.053	0.027
15	0.072	0.078	0.084	0.043	0.051	0.064	0.055	0.074	0.048	0.044	0.044	0.032
16	0.064	0.068	0.078	0.092	0.053	0.059	0.069	0.062	0.080	0.044	0.067	0.040
17	0.125	0.092	0.084	0.061	0.044	0.068	0.056	0.042	0.048	0.046	0.080	0.066
18	0.095	0.094	0.094	0.078	0.060	0.072	0.060	0.056	0.061	0.049	0.066	0.062
19	0.079	0.082	0.068	0.042	0.036	0.023	0.026	0.022	0.034	0.024	0.053	0.059
20	0.039	0.043	0.045	0.042	0.034	0.041	0.031	0.035	0.041	0.036	0.032	0.026
21	0.025	0.037	0.024	0.018	0.013	0.017	0.018	0.015	0.013	0.014	0.023	0.028
22	0.031	0.033	0.014	0.009	0.009	0.015	0.010	0.011	0.012	0.008	0.016	0.014
23	0.014	0.007	0.041	0.064	0.046	0.062	0.042	0.032	0.046	0.055	0.017	0.012

FIGURE C-12: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR NON-PBI OTHER PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.029	-0.030	-0.039	-0.048	-0.043	-0.060	-0.055	-0.050	-0.061	-0.062	-0.038	-0.027
1	-0.038	-0.044	-0.035	-0.027	-0.028	-0.034	-0.035	-0.034	-0.038	-0.034	-0.054	-0.055
2	-0.028	-0.035	-0.027	-0.026	-0.023	-0.025	-0.024	-0.024	-0.025	-0.025	-0.035	-0.036
3	-0.023	-0.026	-0.026	-0.026	-0.025	-0.024	-0.024	-0.024	-0.026	-0.025	-0.025	-0.024
4	-0.023	-0.026	-0.028	-0.026	-0.025	-0.025	-0.025	-0.024	-0.026	-0.026	-0.025	-0.023
5	-0.025	-0.028	-0.032	-0.028	-0.026	-0.026	-0.029	-0.027	-0.028	-0.030	-0.026	-0.022
6	-0.028	-0.031	-0.033	-0.030	-0.031	-0.029	-0.028	-0.027	-0.028	-0.030	-0.028	-0.027
7	-0.041	-0.036	-0.035	-0.035	-0.035	-0.038	-0.036	-0.035	-0.033	-0.031	-0.030	-0.028
8	-0.031	-0.029	-0.041	-0.034	-0.036	-0.034	-0.035	-0.033	-0.031	-0.028	-0.030	-0.028
9	-0.047	-0.048	-0.045	-0.043	-0.045	-0.044	-0.041	-0.041	-0.034	-0.036	-0.044	-0.042
10	-0.059	-0.051	-0.045	-0.045	-0.053	-0.052	-0.047	-0.050	-0.048	-0.040	-0.045	-0.042
11	-0.057	-0.050	-0.052	-0.051	-0.063	-0.060	-0.056	-0.061	-0.055	-0.050	-0.049	-0.045
12	-0.059	-0.048	-0.049	-0.049	-0.057	-0.066	-0.053	-0.058	-0.058	-0.046	-0.051	-0.045
13	-0.062	-0.049	-0.053	-0.050	-0.054	-0.069	-0.060	-0.056	-0.056	-0.049	-0.058	-0.046
14	-0.065	-0.059	-0.052	-0.051	-0.062	-0.073	-0.067	-0.061	-0.058	-0.042	-0.061	-0.045
15	-0.061	-0.056	-0.053	-0.056	-0.070	-0.073	-0.070	-0.069	-0.060	-0.055	-0.062	-0.041
16	-0.063	-0.062	-0.065	-0.061	-0.073	-0.083	-0.066	-0.072	-0.068	-0.062	-0.061	-0.042
17	-0.065	-0.065	-0.065	-0.058	-0.070	-0.078	-0.086	-0.081	-0.077	-0.059	-0.053	-0.039
18	-0.069	-0.064	-0.066	-0.058	-0.060	-0.072	-0.070	-0.055	-0.052	-0.053	-0.067	-0.045
19	-0.082	-0.076	-0.075	-0.081	-0.054	-0.068	-0.056	-0.052	-0.055	-0.051	-0.082	-0.062
20	-0.085	-0.079	-0.058	-0.050	-0.042	-0.049	-0.043	-0.040	-0.042	-0.042	-0.071	-0.065
21	-0.042	-0.036	-0.035	-0.037	-0.033	-0.031	-0.032	-0.028	-0.035	-0.032	-0.035	-0.034
22	-0.036	-0.041	-0.037	-0.031	-0.034	-0.033	-0.034	-0.029	-0.033	-0.030	-0.038	-0.042
23	-0.030	-0.033	-0.033	-0.033	-0.030	-0.034	-0.034	-0.027	-0.032	-0.031	-0.032	-0.028

FIGURE C-13: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR PBI OTHER PROJECTS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.005	0.006	0.006	0.008	0.002	0.002	0.001	0.002	0.003	0.003	0.001	0.001
1	0.003	0.005	0.006	0.008	0.002	0.002	0.002	0.001	0.001	0.001	0.002	0.003
2	0.003	0.005	0.006	0.009	0.003	0.001	0.001	0.002	0.000	0.001	0.000	0.000
3	0.003	0.005	0.006	0.009	0.003	0.003	0.001	0.002	0.001	0.001	0.000	0.001
4	0.002	0.005	0.006	0.009	0.008	0.006	0.002	0.005	0.005	0.002	0.001	0.002
5	0.013	0.006	0.014	0.015	0.017	0.005	0.013	0.003	0.007	0.004	0.002	0.005
6	0.029	0.060	0.066	0.062	0.059	0.049	0.041	0.046	0.042	0.047	0.043	0.043
7	0.055	0.112	0.091	0.064	0.064	0.045	0.048	0.050	0.042	0.045	0.039	0.036
8	0.058	0.026	0.025	0.036	0.023	0.014	0.017	0.010	0.007	0.008	0.017	0.009
9	0.076	0.063	0.037	0.058	0.027	0.025	0.025	0.012	0.011	0.011	0.034	0.013
10	0.051	0.054	0.030	0.048	0.045	0.041	0.032	0.033	0.027	0.023	0.034	0.016
11	0.017	0.041	0.029	0.071	0.094	0.086	0.071	0.070	0.070	0.059	0.044	0.029
12	0.011	0.024	0.031	0.063	0.081	0.084	0.083	0.081	0.074	0.063	0.049	0.037
13	0.020	0.016	0.030	0.053	0.075	0.085	0.087	0.093	0.089	0.068	0.047	0.036
14	0.026	0.016	0.025	0.036	0.086	0.133	0.134	0.150	0.149	0.120	0.060	0.043
15	0.023	0.021	0.021	0.027	0.093	0.136	0.137	0.160	0.169	0.131	0.072	0.053
16	0.024	0.025	0.033	0.034	0.106	0.117	0.140	0.173	0.178	0.146	0.077	0.064
17	0.041	0.030	0.068	0.078	0.069	0.049	0.064	0.048	0.057	0.113	0.090	0.082
18	0.080	0.080	0.134	0.120	0.116	0.125	0.129	0.093	0.124	0.196	0.144	0.138
19	0.164	0.179	0.174	0.186	0.173	0.184	0.165	0.126	0.157	0.205	0.224	0.235
20	0.203	0.236	0.159	0.138	0.132	0.173	0.138	0.113	0.131	0.121	0.233	0.262
21	0.050	0.053	0.043	0.028	0.035	0.048	0.036	0.034	0.033	0.004	0.087	0.116
22	0.009	0.008	0.025	0.035	0.018	0.037	0.032	0.020	0.022	0.031	0.011	0.007
23	0.024	0.018	0.013	0.008	0.002	0.003	0.003	0.002	0.002	0.001	0.025	0.029

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

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.121	-0.122	-0.127	-0.142	-0.197	-0.230	-0.220	-0.205	-0.215	-0.222	-0.234	-0.245
1	-0.106	-0.108	-0.104	-0.128	-0.145	-0.150	-0.164	-0.148	-0.165	-0.151	-0.202	-0.188
2	-0.074	-0.081	-0.079	-0.101	-0.095	-0.113	-0.112	-0.093	-0.105	-0.082	-0.142	-0.129
3	-0.059	-0.056	-0.056	-0.067	-0.059	-0.072	-0.078	-0.051	-0.052	-0.044	-0.090	-0.092
4	-0.057	-0.038	-0.046	-0.048	-0.041	-0.053	-0.049	-0.031	-0.032	-0.028	-0.058	-0.058
5	-0.039	-0.026	-0.041	-0.040	-0.028	-0.036	-0.038	-0.025	-0.024	-0.020	-0.034	-0.041
6	-0.025	-0.023	-0.038	-0.037	-0.027	-0.031	-0.028	-0.021	-0.023	-0.019	-0.027	-0.028
7	-0.023	-0.025	-0.038	-0.036	-0.031	-0.027	-0.021	-0.021	-0.023	-0.019	-0.027	-0.024
8	-0.018	-0.065	-0.060	-0.056	-0.043	-0.036	-0.034	-0.037	-0.030	-0.031	-0.032	-0.026
9	-0.025	-0.092	-0.083	-0.080	-0.070	-0.058	-0.059	-0.062	-0.051	-0.046	-0.049	-0.042
10	-0.028	-0.047	-0.053	-0.052	-0.055	-0.041	-0.038	-0.041	-0.035	-0.028	-0.035	-0.031
11	-0.029	-0.031	-0.039	-0.032	-0.037	-0.019	-0.018	-0.014	-0.020	-0.023	-0.023	-0.022
12	-0.028	-0.026	-0.032	-0.031	-0.018	-0.014	-0.012	-0.009	-0.013	-0.015	-0.018	-0.021
13	-0.022	-0.022	-0.027	-0.029	-0.016	-0.015	-0.011	-0.009	-0.013	-0.016	-0.017	-0.017
14	-0.024	-0.023	-0.032	-0.025	-0.015	-0.017	-0.015	-0.015	-0.020	-0.023	-0.015	-0.013
15	-0.025	-0.023	-0.035	-0.034	-0.014	-0.016	-0.013	-0.013	-0.022	-0.016	-0.015	-0.011
16	-0.020	-0.024	-0.033	-0.035	-0.014	-0.014	-0.010	-0.014	-0.023	-0.014	-0.013	-0.010
17	-0.015	-0.021	-0.023	-0.021	-0.016	-0.018	-0.022	-0.031	-0.032	-0.028	-0.013	-0.010
18	-0.018	-0.023	-0.020	-0.016	-0.013	-0.019	-0.016	-0.017	-0.015	-0.020	-0.029	-0.015
19	-0.015	-0.016	-0.035	-0.021	-0.011	-0.013	-0.017	-0.021	-0.015	-0.022	-0.027	-0.012
20	-0.040	-0.027	-0.035	-0.040	-0.060	-0.050	-0.051	-0.058	-0.050	-0.071	-0.040	-0.021
21	-0.076	-0.063	-0.043	-0.079	-0.119	-0.124	-0.134	-0.123	-0.123	-0.163	-0.052	-0.031
22	-0.170	-0.166	-0.095	-0.120	-0.192	-0.222	-0.205	-0.215	-0.222	-0.203	-0.198	-0.218
23	-0.094	-0.101	-0.118	-0.162	-0.243	-0.280	-0.256	-0.257	-0.265	-0.259	-0.203	-0.213

FIGURE C-15: AVERAGE HOURLY DISCHARGE (KW) PER REBATED CAPACITY (KW) FOR EV CHARGING STATIONS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	0.005	0.001	0.001	0.001	0.008	0.002	0.002	0.002	0.002	0.002	0.002	0.001
1	0.001	0.001	0.001	0.001	0.010	0.003	0.002	0.001	0.002	0.002	0.000	0.002
2	0.001	0.001	0.001	0.001	0.000	0.001	0.002	0.001	0.003	0.001	0.001	0.001
3	0.002	0.001	0.001	0.000	0.001	0.001	0.002	0.000	0.001	0.002	0.001	0.000
4	0.001	0.001	0.001	0.001	0.002	0.003	0.001	0.002	0.000	0.002	0.000	0.000
5	0.011	0.001	0.002	0.003	0.008	0.008	0.005	0.003	0.003	0.007	0.005	0.001
6	0.030	0.001	0.005	0.004	0.012	0.021	0.018	0.016	0.009	0.010	0.007	0.002
7	0.043	0.005	0.023	0.052	0.033	0.037	0.051	0.050	0.043	0.047	0.029	0.006
8	0.077	0.039	0.031	0.083	0.043	0.039	0.046	0.029	0.032	0.040	0.039	0.022
9	0.104	0.113	0.049	0.100	0.057	0.051	0.074	0.059	0.049	0.050	0.080	0.070
10	0.064	0.103	0.056	0.094	0.058	0.060	0.066	0.063	0.046	0.046	0.084	0.082
11	0.028	0.099	0.064	0.085	0.107	0.114	0.118	0.124	0.086	0.072	0.080	0.108
12	0.028	0.073	0.067	0.061	0.105	0.109	0.138	0.133	0.086	0.086	0.073	0.085
13	0.034	0.043	0.054	0.057	0.098	0.104	0.123	0.117	0.085	0.084	0.045	0.066
14	0.049	0.042	0.032	0.055	0.133	0.161	0.168	0.156	0.152	0.136	0.034	0.064
15	0.080	0.036	0.066	0.068	0.121	0.154	0.153	0.138	0.136	0.146	0.051	0.058
16	0.089	0.073	0.076	0.065	0.114	0.131	0.159	0.148	0.122	0.171	0.068	0.060
17	0.086	0.062	0.047	0.072	0.054	0.037	0.051	0.037	0.045	0.109	0.068	0.067
18	0.052	0.033	0.048	0.073	0.057	0.055	0.068	0.057	0.060	0.124	0.104	0.084
19	0.061	0.045	0.034	0.066	0.072	0.063	0.072	0.060	0.056	0.125	0.179	0.136
20	0.070	0.036	0.040	0.049	0.069	0.071	0.055	0.051	0.039	0.084	0.184	0.159
21	0.026	0.016	0.011	0.010	0.031	0.023	0.026	0.018	0.011	0.008	0.069	0.075
22	0.019	0.014	0.013	0.032	0.034	0.025	0.025	0.017	0.012	0.017	0.015	0.008
23	0.046	0.012	0.005	0.001	0.009	0.005	0.006	0.001	0.003	0.003	0.016	0.027

FIGURE C-16: AVERAGE HOURLY CHARGE (KW) PER REBATED CAPACITY (KW) FOR EV CHARGING STATIONS

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.273	-0.242	-0.185	-0.185	-0.209	-0.254	-0.253	-0.210	-0.166	-0.219	-0.290	-0.311
1	-0.248	-0.184	-0.140	-0.113	-0.143	-0.153	-0.164	-0.152	-0.102	-0.108	-0.196	-0.189
2	-0.174	-0.121	-0.083	-0.054	-0.106	-0.104	-0.103	-0.091	-0.058	-0.058	-0.097	-0.114
3	-0.088	-0.056	-0.035	-0.033	-0.069	-0.045	-0.064	-0.047	-0.033	-0.027	-0.045	-0.070
4	-0.081	-0.028	-0.022	-0.021	-0.056	-0.024	-0.033	-0.020	-0.026	-0.021	-0.028	-0.031
5	-0.054	-0.022	-0.019	-0.017	-0.039	-0.022	-0.031	-0.015	-0.022	-0.018	-0.022	-0.019
6	-0.030	-0.017	-0.020	-0.017	-0.027	-0.022	-0.033	-0.017	-0.020	-0.021	-0.018	-0.015
7	-0.023	-0.021	-0.019	-0.014	-0.014	-0.016	-0.020	-0.017	-0.014	-0.012	-0.016	-0.010
8	-0.013	-0.018	-0.013	-0.013	-0.004	-0.006	-0.010	-0.022	-0.016	-0.018	-0.014	-0.007
9	-0.015	-0.025	-0.019	-0.024	-0.010	-0.010	-0.023	-0.032	-0.028	-0.027	-0.027	-0.012
10	-0.019	-0.034	-0.023	-0.021	-0.012	-0.020	-0.024	-0.033	-0.031	-0.038	-0.038	-0.021
11	-0.015	-0.020	-0.012	-0.017	-0.010	-0.008	-0.014	-0.018	-0.026	-0.036	-0.036	-0.021
12	-0.011	-0.012	-0.007	-0.012	-0.004	-0.005	-0.008	-0.009	-0.013	-0.031	-0.035	-0.028
13	-0.007	-0.005	-0.007	-0.012	-0.007	-0.010	-0.007	-0.009	-0.019	-0.028	-0.023	-0.024
14	-0.009	-0.004	-0.005	-0.010	-0.006	-0.005	-0.009	-0.008	-0.011	-0.020	-0.019	-0.016
15	-0.008	-0.004	-0.006	-0.008	-0.004	-0.004	-0.012	-0.009	-0.010	-0.016	-0.015	-0.011
16	-0.003	-0.003	-0.008	-0.015	-0.004	-0.005	-0.009	-0.005	-0.006	-0.008	-0.008	-0.008
17	-0.002	-0.002	-0.007	-0.017	-0.007	-0.011	-0.018	-0.011	-0.010	-0.010	-0.005	-0.009
18	-0.005	-0.004	-0.004	-0.010	-0.011	-0.020	-0.015	-0.008	-0.007	-0.007	-0.008	-0.008
19	-0.003	-0.002	-0.004	-0.006	-0.008	-0.014	-0.010	-0.007	-0.004	-0.005	-0.005	-0.012
20	-0.002	-0.002	-0.026	-0.079	-0.073	-0.074	-0.078	-0.087	-0.064	-0.080	-0.018	-0.009
21	-0.017	-0.034	-0.050	-0.134	-0.152	-0.143	-0.152	-0.150	-0.126	-0.198	-0.071	-0.043
22	-0.109	-0.134	-0.095	-0.137	-0.180	-0.219	-0.240	-0.226	-0.193	-0.240	-0.235	-0.265
23	-0.086	-0.126	-0.157	-0.277	-0.308	-0.336	-0.362	-0.310	-0.270	-0.356	-0.242	-0.221

FIGURE C-17: BILL IMPACTS – PG&E PBI TOU ENERGY ONLY RATE (N=9)

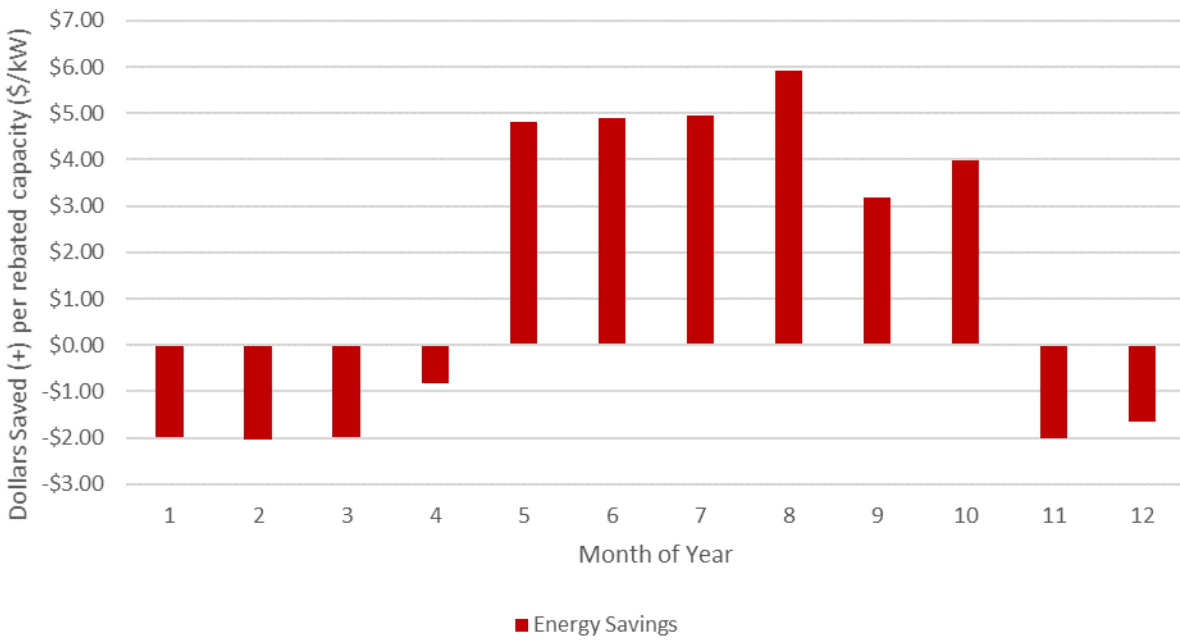

FIGURE C-18: BILL IMPACTS – PG&E NON-PBI TOU WITH MONTHLY DEMAND ONLY (N=4)

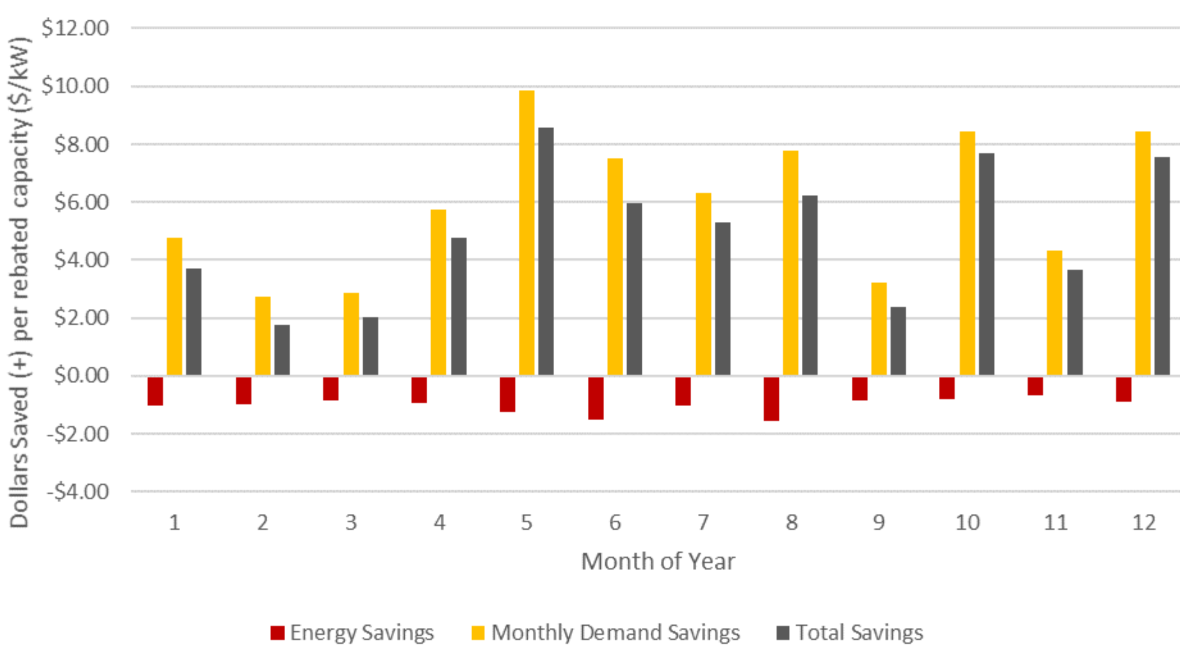

FIGURE C-19: BILL IMPACTS – PG&E PBI TOU WITH MONTHLY DEMAND ONLY (N=6)

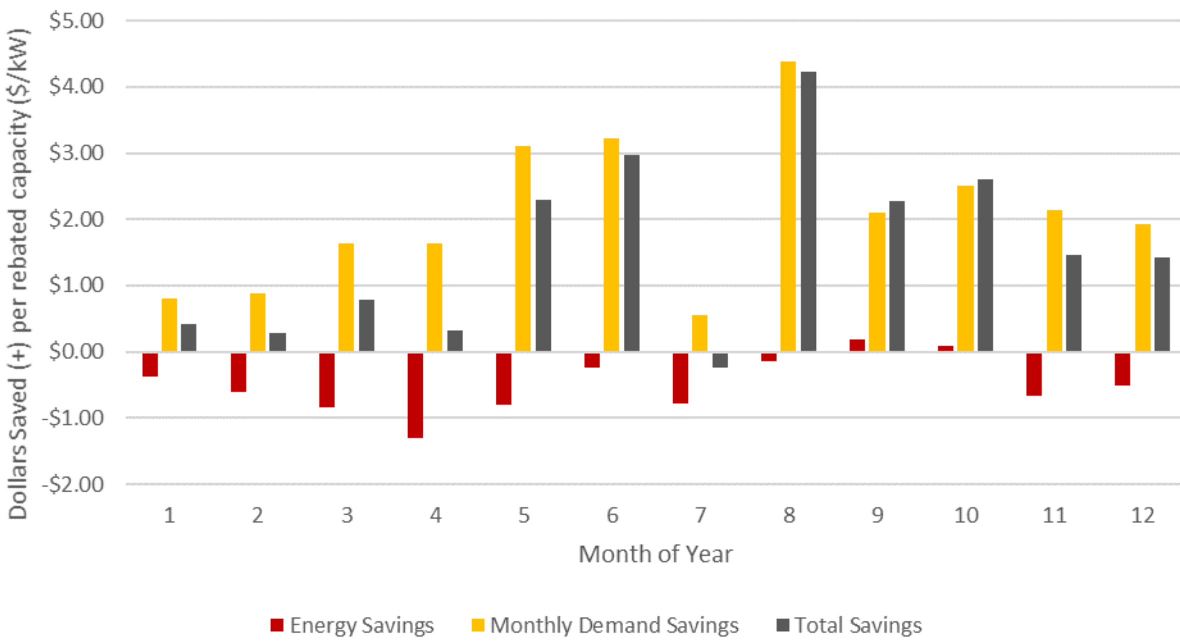

FIGURE C-20: BILL IMPACTS – PG&E NON-PBI TOU WITH MONTHLY AND PEAK DEMAND (N=75)

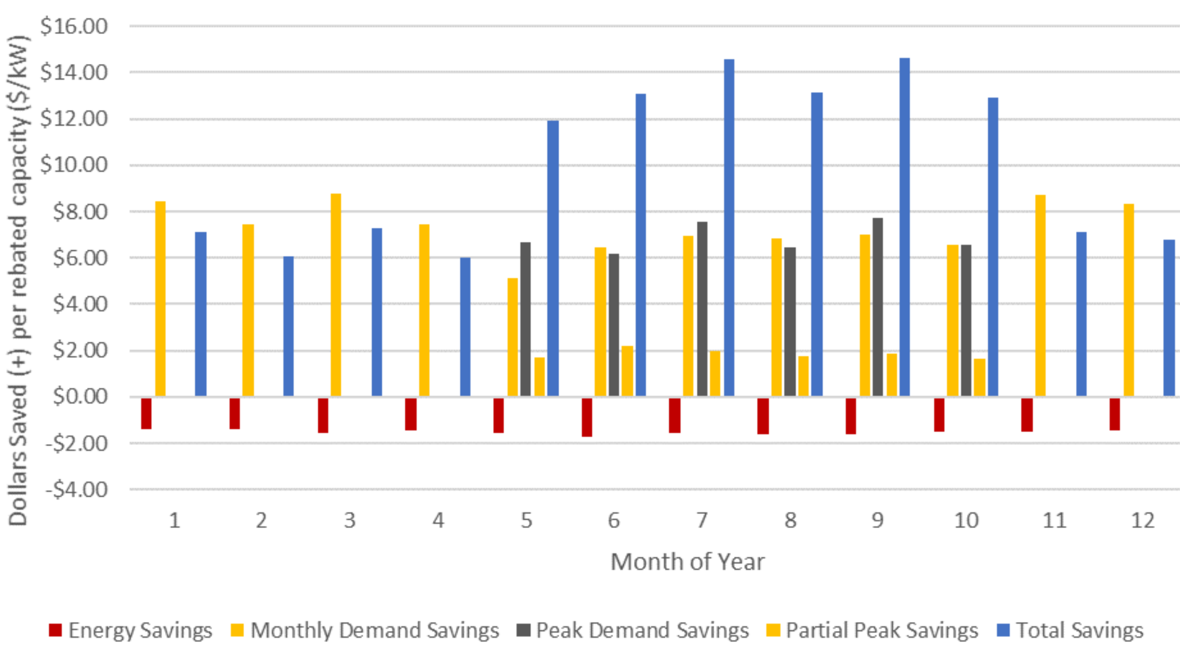

FIGURE C-21: BILL IMPACTS – PG&E PBI TOU WITH MONTHLY AND PEAK DEMAND (N=18)

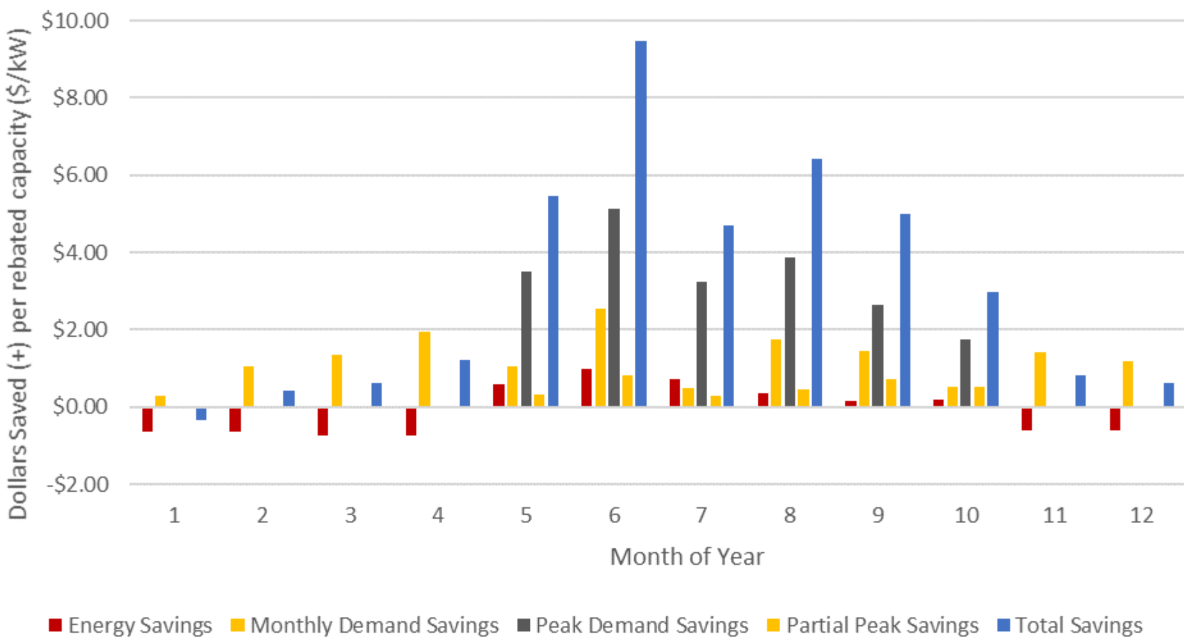

FIGURE C-22: BILL IMPACTS – SCE NON-PBI TOU WITH MONTHLY AND PEAK DEMAND (N=18)

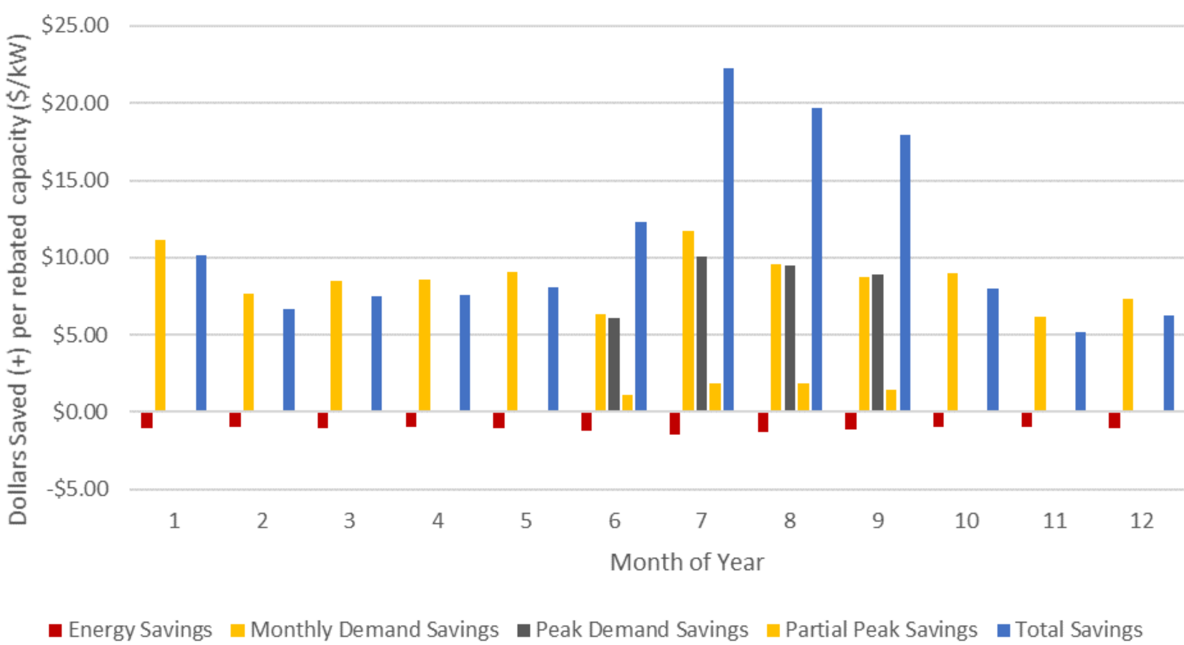

FIGURE C-23: BILL IMPACTS – SCE PBI TOU WITH MONTHLY DEMAND ONLY (N=2)

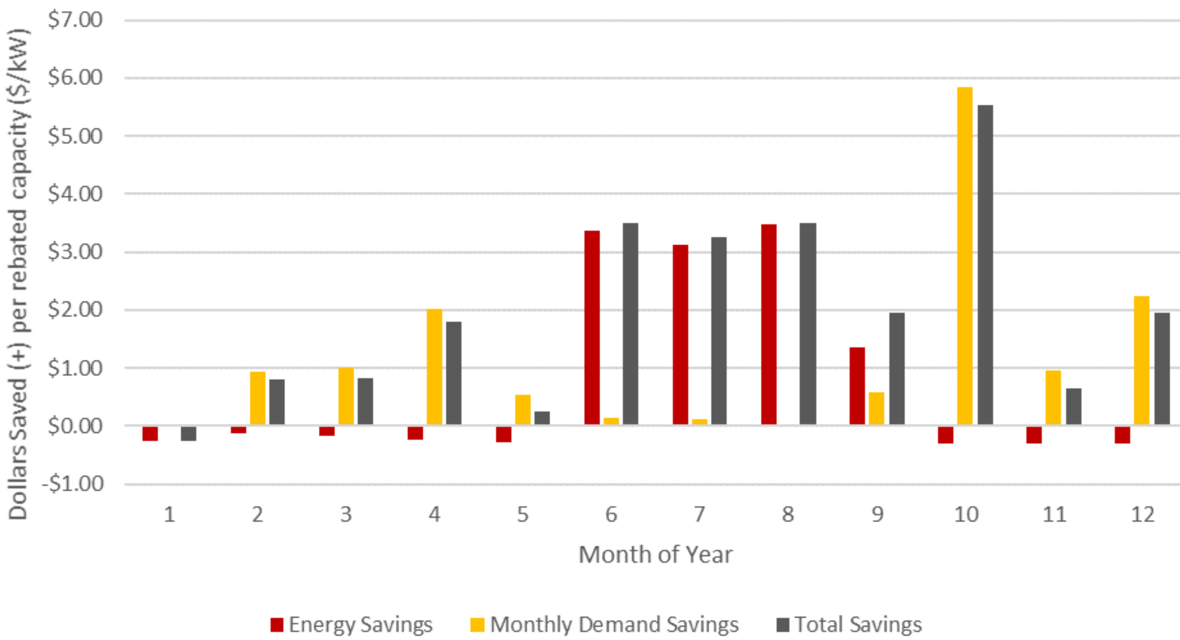

FIGURE C-24: BILL IMPACTS – SCE PBI TOU WITH MONTHLY AND PEAK DEMAND (N=25)

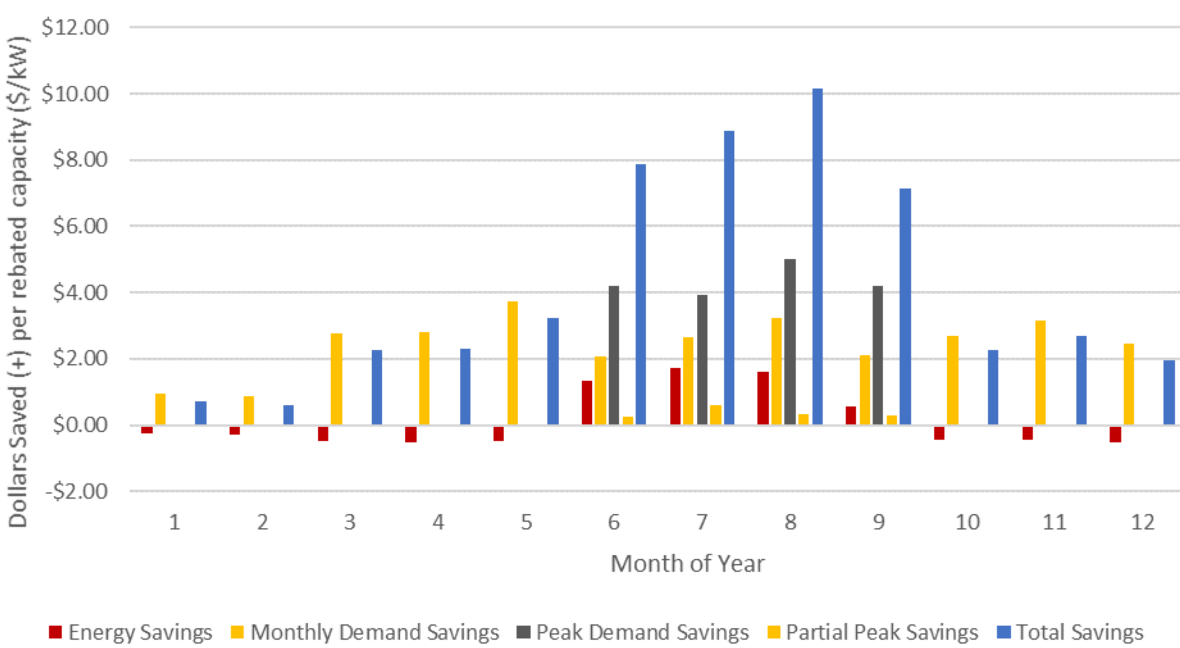

FIGURE C-25: BILL IMPACTS – SDG&E NON-PBI TOU WITH MONTHLY DEMAND ONLY (N=1)

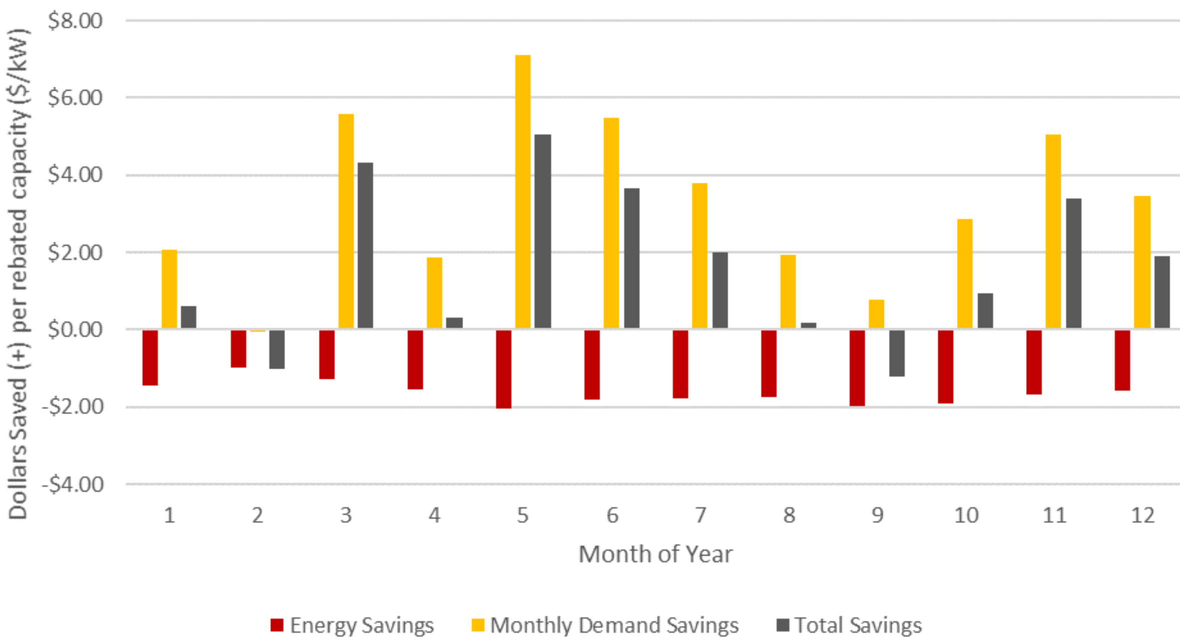

FIGURE C-26: BILL IMPACTS – SDG&E NON-PBI TOU WITH MONTHLY AND PEAK DEMAND (N=53)

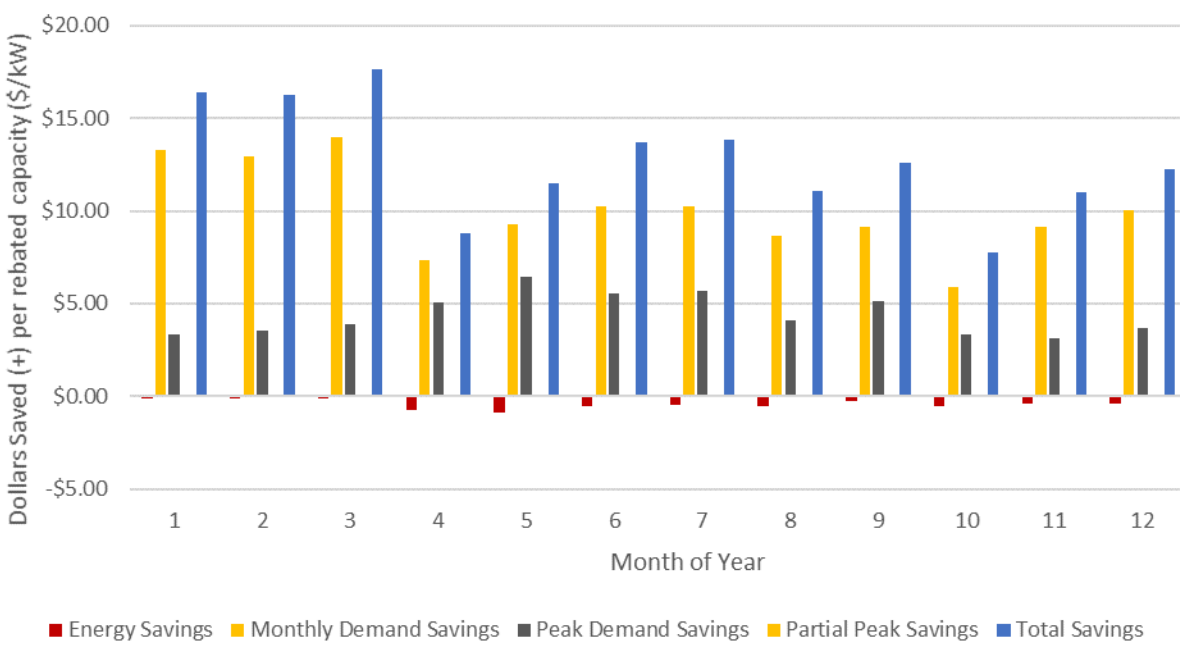

FIGURE C-27: BILL IMPACTS – SDG&E PBI TOU WITH MONTHLY AND PEAK DEMAND (N=11)