California Solar Initiative
Research, Development, Demonstration, and
Deployment Program

Baseline Report

PV AND ADVANCED ENERGY STORAGE FOR DEMAND REDUCTION

Priority Area 2.2

Improved PV Production Technologies

Prepared For:

California Public Utilities Commission & Itron

Prepared by:

SunPower Corporation

In collaboration with:

KEMA
Sandia National Laboratories

Storage Manufacturer Vendors:

Prudent Energy
Ice Energy
ZBB Energy

Advisory Partner:

Pacific Gas & Electric

January 13, 2012

Table of Contents

EXECUTIVE SUMMARY **3**

BACKGROUND **4**

METHODOLOGY & APPROACH **5**

ASSUMPTIONS 5
MAXIMUM VALUE APPROACH 5
DETAILED MODELING APPROACH 8
SITES MODELED 9

OUTCOMES & OBSERVATIONS **10**

IMPACT OF PV ON DEMAND CHARGES, AND IMPLICATIONS FOR ENERGY STORAGE 10
MAXIMUM VALUE APPROACH RESULTS 12
DETAILED MODEL RESULTS 13
RISK FACTORS IMPACTING DELIVERED VALUE 18
OTHER FACTORS 20

INITIAL CONCLUSIONS & RECOMMENDATIONS **22**

NEAR-TERM COMMERCIAL VIABILITY OF COMBINING PV AND ENERGY STORAGE 22
RATE DESIGN 22
DEMONSTRATION SITE SELECTION 23

APPENDIX A – REPORT REQUIREMENTS FROM SOW **24**

TASK 2: ESTABLISH BASELINE 24

TABLE OF TECHNICAL TERMS **25**

Disclaimer

This report was prepared as an account of work sponsored by CPUC and administered by Itron. Neither the CPUC, Itron nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product or, process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Executive Summary

This report summarizes the results of an initial estimate of economic benefits to the customer by combining photovoltaic (PV) with energy storage to manage time-of-use, demand charge rates.

These results were obtained by modeling the impact of different energy storage systems on customer utility bills, using actual facility load and time-coincident PV output data. A thorough review and discussion of the modeling methodology and results, benchmarked against public studies of energy storage value in similar applications, is provided. Additionally, a number of other important considerations such as siting, permitting, PV and load profile variability, system sizing, reliability, incentive policy, utility regulations and additional market opportunities for storage are discussed.

The key finding of this preliminary report is that under current market conditions, and with allowances for some variability between individual energy storage technologies, energy storage costs appear to substantially exceed the benefits that can be captured by the end user in this application. However, in some cases, the availability of incentives should allow customers to achieve a positive return on investment for this application today. Broadly speaking, the report's conclusions suggest that there is a significant amount of work ahead for the project and its vendors in order to prove out the commercial viability of a combined PV and energy storage value proposition. Further research is required before a final analysis can be made and this document should provide an indication of where that work should be directed as the project moves forward.

Two key recommendations are provided. First, the results reaffirm the need to operate energy storage systems in this particular application in order to gain a more comprehensive view of both economic and technical performance under real-world conditions. Second, rate design is a crucial determining factor for the economics in this application. We note time-of-use energy rates would likely better incent the deployment of energy storage than time-of-use demand rates.

Background

On September 2nd 2010, the California Public Utilities Commission (CPUC) approved SunPower's grant application entitled, "PV and Advanced Energy Storage for Demand Reduction," a demonstration[1] project to test if the integration of PV and energy storage could be of higher value than either technology alone.

This project falls under the rubric of the CPUC's California Solar Initiative (CSI) Research, Development, and Deployment (RD&D) program and is designed to help build a sustainable and self-supporting industry for customer-sited solar in California. To achieve this, the legislature authorized the CPUC to allocate $50 million of the California Solar Initiative budget to focus on:

- Reducing technology costs and increasing system performance
- Focusing on issues that directly benefit California
- Filling knowledge gaps to enable wide-scale deployment of distributed solar
- Supporting the integration of distributed power into the grid

This CSI project includes tasks to increase demand reduction and verify benefits of solar coupled with energy storage, and also to assess the reliability and performance of three different storage technologies. The storage options include an innovative thermal energy storage technology and two advanced electrochemical storage technologies.

The specific goals of this research project are to:

1. Determine if the combined value of PV and energy storage is of higher value to the commercial customer and utility than either one alone, and,
2. Assess storage capabilities, reliability and potential degradation of the technologies to assess lifetime characteristics.

This baseline report is intended to provide a detailed, initial assessment of the interaction of photovoltaic (PV) and energy storage (ES) systems relative to time-of-use (TOU) utility tariffs which include demand charges. This type of rate structure is the most common for commercial electricity customers in California.

The report is based on preliminary modeling of the technical and economic performance of proposed energy storage systems at several large commercial retail sites, using actual facility load and PV production data. The results of this modeling are discussed in detail. In addition, we discuss the implementation experience to date and provide recommendations on how to best incentivize customers to deploy energy storage behind the meter in conjunction with PV.

[1] Activities which bring promising technologies closer to market by demonstrating their real-world feasibility to manufacturers.

Methodology & Approach

Assumptions

For all analysis performed in this study, the following base assumptions were used:

Financial		
Discount (hurdle) rate	5%	
Base Utility Rate	PG&E E19S - March 2011	
Utility rate escalator	2%	per year
Federal tax rate	30%	
State tax rate - CA	8.80%	
Federal tax depreciation - PV	5 year MACRS	
Federal tax depreciation - Storage	Straight line over asset life	
State tax depreciation - PV	12 year straight line	
State tax depreciation - Storage	12 year straight line	
Incentive - PV	Federal ITC	
Incentive - Storage	None	
PV Specific		
O&M Cost	$0.01 / W	annually
System Life	30	years
Inverter Replacement Interval	Years 10 and 20	
Inverter Replacement Cost	$0.10 / W	

Table 1: Baseline Model Assumptions

For the vendor-specific modeling performed, fairly detailed assumptions were utilized. These inputs were provided by the vendors, under NDA, and have not been independently verified. The assumptions include detailed efficiency data, including how efficiency varies as a functional of operational state; cycle life vs. depth of discharge; O&M costs; and the vendor-supplied dispatch protocol. While the bulk of the vendor data used in the model is confidential, the basic attributes of each system are as follows:

Vendor	Power	Energy	Average RT efficiency	Operational Life	Technology Type	Notes
Ice Energy	107 kW	642 kWh	100%	25 Years	Thermal	Based on 14 units
ZBB Energy	125 kW	500 kWh	65%	10 Years	Zn-Br Redox	
Prudent Energy[2]	200 kW	600 kWh	65%	10 Years	V Redox	

Table 2: Basic System Attributes

Maximum Value Approach

To provide context for the value of energy storage in this application, it is important to understand the maximum possible value for the system under the tariff. This value is independent of the facility

[2] The Prudent Energy system modeled is larger than the planned system for the pilot, as this smaller demonstration system is disproportionally more costly to install.

load and PV generation (if any) and is simply a reflection of the unconstrained revenue generation potential of the asset.

The maximum possible value of an energy storage system on a TOU demand rate can be easily determined. This is done by assuming that the ES system reduces peak (and potentially part-peak) demand by the nameplate power rating each month. Additionally, it is straightforward to compute the arbitrage value by assuming the maximum allowable charge (on off-peak) and discharge (on part-peak or peak) for every available day there is a rate spread.

A basic calculation of this maximum possible annual value is expressed by the following equation:

$$(P_s)(R_{PD})(M_{PD}) + (E_S)(R_{PE} - R_{OPE}/\eta_{RT})(D_{PE})$$

(eq. 1)

Where:

P_s = Storage power rating (kW)

R_{PD} = Peak demand rate ($/kW)

M_{PD} = Number of months with peak demand rate per year

E_S = Storage energy rating (kWh)

R_{PE} = Peak energy rate ($/kWh)

R_{OPE} = Off-peak energy rate ($/kWh)

η_{RT} = Round-trip efficiency

D_{PE} = Number of days with peak energy rate per year

In this equation, we ignore all part-peak demand and energy periods both in the summer and in the winter. Analysis shows that, under the PG&E E19 rate, the additional energy storage (kWh) needed to completely cover part-peak periods (summer and winter) does not appear to be worth the gain achieved by doing so, given relatively low demand charges and small rate spreads. All-hours demand charges are also ignored in this simple formulation. Reduction or increase of these all hours demand charges may occur, dependent on load shape, dispatch strategy, and system sizing.

As an example, we can calculate the value of an incremental kW and kWh on the E19 tariff for a system with 65% round trip efficiency.

Using:

P_s = 1 kW

R_{PD} = $12.11 / kW

M_{PD} = 6

E_S = 1 kWh

R_{PE} = $0.1458

R_{OPE} = $0.0861

η_{RT} = 65%

D_{PE} = 128

We find the following:

Maximum Value (Year 1)	
Demand Savings (per incremental kW per year)	$72.66
Energy Arbitrage (per incremental kWh per year)	$1.71

Table 3: Incremental Value of Energy Storage

Clearly, the bulk of the value obtained under this tariff is based on avoiding summer demand charges; the value of energy arbitrage is small. This is because the efficiency of the battery results in a near-zero rate spread. That is, the off-peak rate of $0.0861 divided by 65% = $0.1325, for an effective arbitrage spread of $0.013 per kWh of storage per day. For efficiencies below about 59%, the value of summer energy arbitrage is negative. For higher efficiencies, and as the energy to power ratio increases, the relative value of energy arbitrage to demand savings becomes progressively more significant. The differences between technologies, including efficiency, are reflected in Table 2 (page 5).

It is useful to model the value proposition of a generic, ideally operated energy storage system to separate the impacts of financial modeling – such as tax implications, discount rate, etc. – from the proprietary vendor-specific characteristics including efficiency curves, dispatch protocol, and so on.

As an example, we model a representative energy storage system with the following characteristics and assume that it is ideally dispatched to achieve the maximum possible value. The goal is to model the Break-Even Net Present Value (B/E NPV) of the system – that is, the installed cost which results in just meeting the hurdle rate.

Financial assumptions are as above. For technical assumptions, we use the following basic inputs:

- Nameplate Charge / Discharge Power: 100 kW
- Nameplate Energy: 400 kWh usable
- η_{RT} = 65%
- O&M cost: $1000 per year
- Asset life: 10 years
- Summer operation only

Based on these inputs, per the above, the year-1 value provided by the system is $7949. The B/E NPV of this hypothetical system is then $54,882. This equates to an installed cost of $549/kW, or $137/kWh. As a comparison, using similar methodology and PG&E E19 rates, but different

economic assumptions and an 80% efficient device, Sandia National Laboratories in their 2010 "Electric Energy Storage Technology Options" estimated a value of $582 / kW for a 6-hour system, or $97 / kWh.

Detailed Modeling Approach

While the very simple approach outlined above is quite useful in establishing an upper bound to the potential value of an energy storage system given a particular rate tariff, to determine the value of a specific technology at a specific site, a much more detailed model is needed.

SunPower previously developed such a model. It is based on a time-series analysis of 1 year, 15-minute resolution load (demand) and PV production data.

The model can very flexibly incorporate the nuanced operational differences between different energy storage systems, as it calculates the "state" of the system in each time step based on energy flow into and out of the storage system, including efficiency losses. For instance, charging efficiency and discharging efficiency are treated separately in the calculation because charging and discharging occur at different times (and at different prices). If the input parameters affecting this energy flow are not independent, this also can be modeled. Different dispatch approaches also can be incorporated which can operate based on load, PV output, the combination (net load), time-based dispatch, and other factors as needed. Of course, the model also incorporates the constraints of the system such as charge and discharge power, minimum allowable state of charge, and so on to ensure that the model does not predict storage operation which cannot physically occur.

The model calculates the cost of utility service in each time step, based on the specific rate tariff. It calculates separate energy ($ per kWh) and demand ($ per peak monthly kW) charges across multiple time of use periods, including weekend and holiday exceptions to these periods. The components of the utility bill - energy, demand, and fixed charges - are calculated separately for a base case, a PV-only case, or a PV plus storage case. Different rate structures can be assigned to each case. This results in a "year 1" utility cost for each case.

The single-year results from this model are passed to a cash flow model which is used to determine NPV and IRR for each case given the expected operational life of the PV system and energy storage system. The cash flow model incorporates O&M costs for the PV and storage systems as well as changes over time in both systems, such as efficiency, output power, or energy capacity where these occur and data is available. The cash flow model also incorporates federal and state tax considerations, including depreciation. For this application California state taxes were assumed.

With the energy storage system size set to zero, this model was validated against the economic model used by SunPower sales analysts and was demonstrated to achieve nearly identical results. Investigation of the differences found that these stemmed from the use of a 15 minute time increment in this model (versus an hourly increment in the standard model), which impacts demand charges.

Modeling proceeded somewhat differently for Ice Energy. Because the performance of that system is dependent on building HVAC load, which increases as a function of rooftop ambient air temperature, Ice Energy provided the output from their proprietary model and this was used instead of the operational submodel within the SunPower tool.

Sites Modeled

The original host sites planned for this project were properties of a major big-box retailer located in hot summer climates within PG&E service territory. The three stores were in the cities of Gilroy, Stockton, and Clovis. Each of these sites also has a PV system previously installed by SunPower. SunPower has 15 minute interval PV production data for each site, and 15 minute interval meter data was provided by PG&E for the Gilroy and Stockton locations. Unfortunately, PG&E was unable to provide interval data for the Clovis store, so this facility is excluded from the analysis.

Because the meter data was net of PV production, the PV production data had to be added back to the meter data to reconstruct facility load. This required minor data manipulation, specifically "lining up" timestamps, and a negligible amount of interpolation in the few instances where data points were missing. This resulted in a successful reconstruction of facility load. Data from 2010 was used, and in addition data from 2008 was used for the Gilroy store. The 2008 Gilroy data set did not include sufficient meteorological data to model the performance of the Ice Energy system.

Some relevant statistics for each site are shown below:

	Stockton (2010)	Gilroy (2010)	Gilroy (2008)
Maximum peak period load (kW)	497	446	464
Average annual load (kW)	255	192	225
PV nominal system rating (kWp, DC)	370	381	381
PV maximum output (kW, AC)	309	327	314

Table 4: Site Characteristics

Outcomes & Observations

Impact of PV on Demand Charges, and Implications for Energy Storage

The basic premise of combining PV and energy storage is that the PV system reduces demand across much of the peak period, but energy output is significantly reduced towards the end of the period so the actual impact on the demand charge is limited. In addition, reductions in PV output (for instance, from passing clouds) could reduce output at any time in the day, impacting demand charges. Figure 1 shows a fairly typical case, where peak demand is dominated by the afternoon roll-off of PV generation despite some partly-cloudy conditions mid-day.

The data analyzed in this study does show meaningful reduction in facility demand charges based on PV alone, though the magnitude of this reduction can vary significantly. This can be readily visualized in Figure 1, which illustrates a day where PV achieves 65 kW of demand reduction with a peak AC output of about 250 kW.

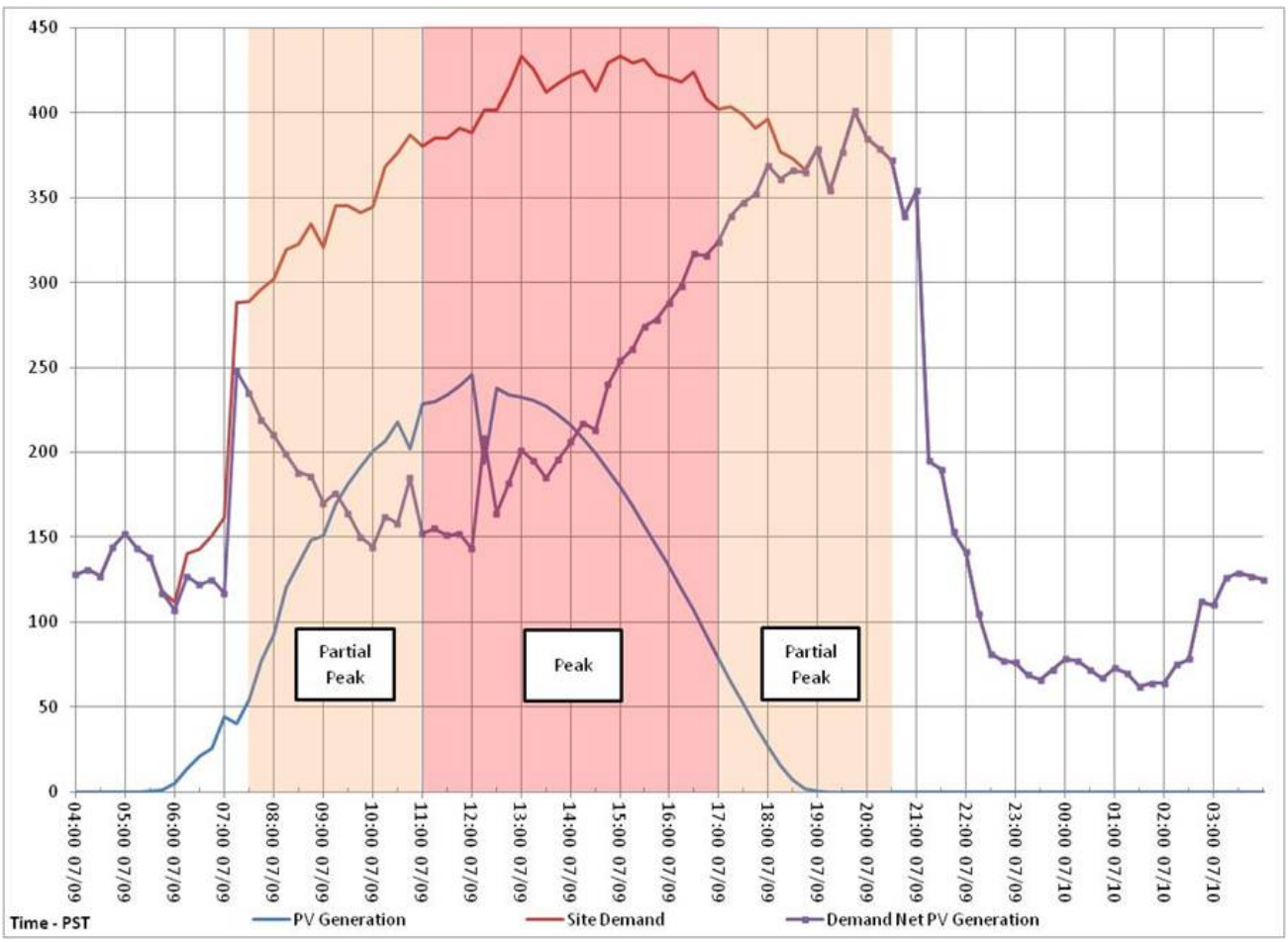

Figure 1: Impact of PV on facility demand and load shape – July

Although the output of the PV system contributes little to reduce demand in the final 15-30 minutes of the peak demand period, by late afternoon facility demand has also dropped from its peak. Also observe that partly cloudy conditions on this day, causing depressions in output mid-day, have no impact on the demand reduction. Observation of the data used for this analysis indicate that short-duration depressions in output due to this kind of fair-weather clouds does not generally cause large

increases in demand relative to a clear day, because over a 15 minute averaging period it is rare for such reductions in power to exceed 50%; this is not enough to set the demand charge. However, extended cloudy conditions which depress output for a significant portion of the day, such as overcast conditions, can impact demand charges. Another important point relates to PV system reliability. The limited demand reduction observed at Stockton was primarily due to PV system outages during the summer which resulted in inverters occasionally being turned off for several hours; this occurred in most of the summer months[3]. Similarly, in the Gilroy 2010 data, the contribution of PV to reducing demand charges was limited in June due to a single day in that month where the PV system was offline.

A more complete analysis of the "natural" demand reduction of PV systems at the sites included in this study is shown in Figure 2, which shows that across the three sites / years analyzed, PV consistently achieved demand reductions ranging from about 5% to 46% of the nameplate DC rating, including the outages discussed.

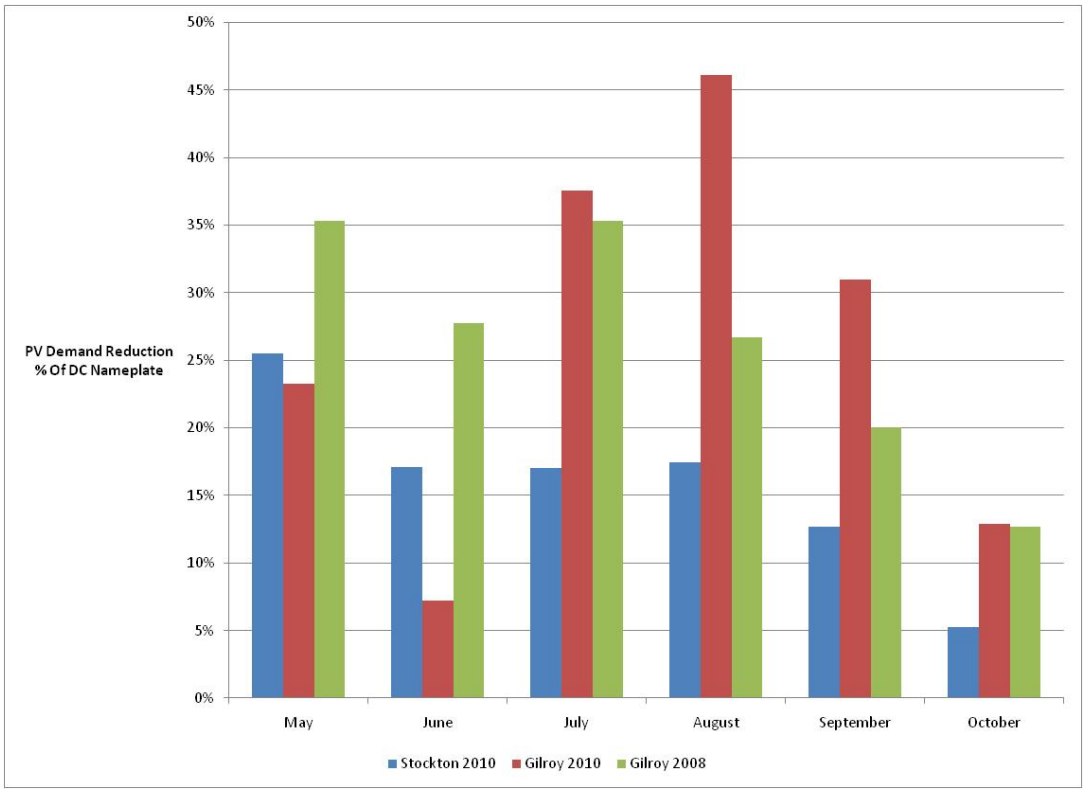

Figure 2: PV system summer peak demand reduction.

Adding energy storage has the potential to further improve the value of the PV system by "covering" facility demand during periods when the PV system is not producing enough power to impact the demand charge. Conversely, the presence of the PV system means that the amount of energy stored to ensure that demand is reduced can be reduced considerably. As discussed above, this has a significant impact on the cost of energy storage, particularly as expressed on a $/kWh basis.

[3] The particular make and vintage of inverters deployed at this site, from one of the major inverter suppliers at the time, have demonstrated systematic reliability issues. Market share of this manufacturer has plummeted accordingly; SunPower has not used products from this manufacturer for many years and PV system reliability / availability is normally much higher.

In effect, the presence of the PV system makes the resulting load extremely "peaky". The more "peaky" the load shape, the more demand reduction impact can be achieved per kWh of storage deployed. As an example, for one site the facility peak to average load ratio during the peak billing period was 1.3, a fairly flat load shape, versus 2.1 with PV installed. Therefore, in principle, a situation with a significant amount of PV onsite represents the best case scenario for storage economics in a behind the meter, demand charge reduction scenario; particularly where system costs are strongly influenced by storage duration.

The primary implications for pairing energy storage with PV are:

- Load profiles with PV in place are much more "peaky" with a steep pick-up in load over the final hour of the peak demand period.
- "Fair weather" clouds do not typically impact demand charges in the PV only case, and will likely have limited impact on demand charge reduction with storage in place, given the kW rating of the storage devices considered here. As storage system power ratings increase relative to the PV system rating, short duration reductions in PV output due to fair weather clouds become an increasingly more significant factor.
- Overcast conditions can significantly reduce PV output for many hours and can impact demand charges, however, facility loads are also generally lower under these conditions which mitigates the impact. In other words, the presence of the PV system can result in the peak demand day for the month being shifted from a clear day to an overcast day, with attendant reduction in demand charges.
- Reliability and uptime of both the PV and energy storage system is critical to achieve demand reduction. This is discussed in detail below.

Maximum Value Approach Results

The theoretical maximum possible value for each system, computed per Equation 1 from basic publically available performance characteristics, O&M cost estimates provided by the vendors, and the financial assumptions given previously, is:

Technology	Year 1 Avoided Utility Cost	$ B/E NPV[4]	B/E NPV - $/kW	B/E NPV - $/kWh
Ice Energy	$12,676	$176,767	$ 1653	$275
ZBB	$9,936	$66,800	$534	$134
Prudent Energy	$15,556	$75,364	$377	$126

Table 5: Theoretical Maximum Values

This is an idealized benchmark for a system with these basic characteristics. This benchmark does not include many critical factors, which are discussed in detail in this report. It is important to note that since the vast majority of the value is provided by demand reduction, achieving the same demand reduction with less energy onboard the battery significantly increases the value on a $/kWh basis. That is, a system that could manage to achieve ideal demand reduction with only 2 hours of energy would be worth nearly twice as much on a $/kWh basis. This is the basic premise of combining the two systems.

[4] Includes O&M costs

Detailed Model Results

The results from the model are shown in the following table.

	Stockton (2010) B/E NPV		Gilroy (2010) B/E NPV		Gilroy (2008) B/E NPV		Average	
Technology	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh
Ice Energy	1193	199	1071	179			1132	189
ZBB	247	62	202	50	295	74	248	62
Prudent Energy	<0	<0	<0	<0	44	15	N/A	N/A

Table 6: Model Results

Clearly, these values are significantly lower than the maximum value. In the cases where B/E NPV is less than zero, it is because the benefit (avoided utility costs) from operating the system in this application and configuration are less than the variable costs to operate the system. The reason for this is related both to dispatch strategy utilized by the systems, and the power and energy configuration of the systems, which was chosen prior to detailed analysis. More optimized sizing and dispatch could lead to benefits more consistent with the maximum value analysis. Additional value streams, as discussed below, may also significantly improve energy storage system economics.

For this reason, the specific financial results for these particular system configurations are not necessarily representative of what would be expected in a commercial deployment. They should not be used to evaluate the potential economic benefits of a particular vendor's solution.

However, the modeling exercise does provide significant insight into why these results occur, and what the implications are for combining PV and energy storage in this application. In particular, it is possible to gain insight into how closely actual operating results could match the maximum value that is calculated strictly from the potential tariff benefit.

The results are strongly influenced by year-1 performance, which is dictated but the power and energy rating of the system, the PV and load profiles, and the dispatch strategy. The B/E NPV further considers O&M costs, tax costs and benefits, the service life of the system, and changes over time including the utility rate escalator and any performance degradation.

Note, however, that the PV generation and load shape do not change from year to year in the model; the impact of this is significant and is addressed in the following section.

Value and Cost

The main question raised by this analysis is whether the technologies considered in this pilot have a clear pathway to commercial viability in this application within the next 2-3 years. This is crucial because the premise of the pilot was to demonstrate the technical and economic viability of near-commercial energy storage solutions combined with PV to achieve synergistic energy cost reduction; a successful demonstration of feasibility is expected to lead to a commercial offering of such a system.

The analysis presented above provides some data to assess this. However, while the detailed modeling results are useful in understanding the financial performance of the specific systems on each site, it is not necessarily representative of the performance of a system optimized for the PV plus storage application. As discussed previously, the storage systems could have been sized to capture the same demand reduction value with less energy, and thus at a higher value per kWh. However, this analysis indicates that the achievable gains are limited. While it may be possible to

size the system perfectly for a set of conditions in a model, actual operating conditions (e.g. net load) will vary over time. To a greater or lesser extent, this leads to either under- or over-sizing in any given operational year, and the consequence of both under- and over-sizing storage is a reduction in net value. In the case of over-sizing, this is simply because the additional cost per kWh, added on top of the minimum required to achieve maximum demand charge reduction, achieves little incremental additional value. That is, the $/kW value remains constant but the $/kWh value decreases proportionally. If undersized the storage system will run out of energy prematurely and thus maximum demand charge reduction will not be achieved. Even slightly under-sizing the system or discharging it in such a way that energy is not available when needed to reduce demand, can have a very detrimental effect on value. If undersized, the value on a $/kW basis drops because the level of energy on board does not allow the full power of the system to be utilized.

To illustrate this, a case study was performed with a 100 kW battery system that was optimally sized based on historical Gilroy 2008 PV and load data, then "operated" using a model dispatch algorithm against Gilroy 2010 data. This system was modeled with very similar characteristics to the ZBB and Prudent technologies, but with simplified operational details (e.g. fixed 65% round trip efficiency) to facilitate faster computational iterations. The main goal was not to model a particular vendor's technology, but rather to understand the variance in performance from year to year at the same site for the same system.

For this exercise, the optimal baseline battery size was found to be 1.7 hours, which in the baseline year delivered an avoided cost of $6530, amounting to 99.6% of the theoretical maximum value. If this level of performance was maintained over the 10-year life of the system, the B/E cost of the system would be expected to be $516/kW or $187/kWh. As expected, the PV and storage systems combined offset essentially the full kW capacity of the storage system over the full 6 hour demand period - while requiring less than 30% of the onboard energy which would have been needed to achieve the same demand reduction without PV in place.

In 2010, however, the same system would have actually delivered an avoided cost of $4400, just over 67% of the baseline value. If we consider this performance to be more typical of the "norm" – that is, representing an operational year that differs "typically" from the data used for sizing - the 10-year B/E cost would be $345/kW or $203/kWh. Overall, in 2010, the facility net load and peak demand in each month was reduced substantially (about 20%-30%) compared to 2008. However, the reduction in value in 2010 was actually due to under-sizing of the storage system. In these months, as illustrated in Figure 2, the PV system delivered relatively little demand reduction in 2010 as compared to 2008, which in turn impacted the ability of the storage system to deliver demand reduction because insufficient energy was available. Note that this lack of demand reduction had little effect on the PV system's financial performance, because demand savings make up a relatively small amount of the PV value proposition in the first place; the PV system value in 2010 was 95% of the 2008 baseline.

What these results demonstrate is that in practice, the actual value that energy storage can achieve in this application may be less than might be assumed by just looking at the peak reduction and energy arbitrage potential.

Based on these results, one could generalize towards two strategies. The first would be to minimize the amount of energy in the storage system, maintain dependence on the PV system performance and accept the tradeoff of a lower $/kW value in exchange for a relatively higher $/kWh value. For example, if you make the reasonable assumption that 2 hours of storage will be sufficient to reduce demand most of the time, the value of storage over the life of the system in this application might be

reasonably approximated as $350/kW or $175/kWh. This represents a preliminary estimate of priced-in risk based on the modeling done to date. Conversely, the energy storage system could be sized to reduce demand in all cases, regardless of PV performance. To eliminate any risk of not achieving kW nameplate demand reduction, six hours of storage would be required. In this case the theoretical maximum value could likely be achieved, approximated at $520/kW or $87/kWh for the flow batteries. This effectively eliminates the risk by over-sizing the system, but results in a much lower $/kWh value so again "pricing in the risk".

The Ice Energy system is designed specifically for facility demand reduction and, as such, has a 6 hour duration – in essence the latter strategy above. The operation of the system is such that it shifts the facility demand curve downward; the amount of reduction is a function of outside air temperature (OAT), with more reduction at higher OAT. In this application, where a large PV system is in place, the system is oversized. Because the PV system is operating during mid-day and significantly reducing demand, the demand offset achieved by the Ice system typically has no impact on demand charges until late afternoon, when facility demand has started to decline. Additionally, in some cases the peak demand with PV in place is set on partly cloudy days, when PV output is consistently depressed. These conditions are associated with cooler ambient temperature, leading to reduced demand reduction from the thermal storage system compared what would have been achieved on a hot, sunny day with no PV in place. The net effect is that the Ice Energy system achieves a lower value with the PV system in place than if no PV system had been in place. For example, in Gilroy 2008 the B/E value of the system would have been $1406/kW with no PV, versus $1071/kW with PV, a 24% reduction. Conversely, for Stockton the reduction in value is just 7% - the longer duration provided by the solution ensures coverage of demand for the unusual number of PV system dropouts discussed previously. A more PV specific dispatch strategy and/or a reduction in storage duration would be needed to making the combined application of technologies more synergistic.

Naturally, it is important to consider a full range of potential customer benefits. While not within the scope of the current pilot, it is worthwhile to discuss potential stacked benefits. To estimate the value of these benefits, we reference recent studies by the Electric Power Research Institute (EPRI)[5] and Sandia National Laboratories[6].

It is worth noting that there are numerous potential value streams for distributed storage than have been widely discussed, including benefits which accrue to the utility that are not necessarily fully reflected in the customer's avoided costs (such as T&D investment deferral) and future value streams (such as providing ancillary services). At this time, it is unclear how or if these values will be quantified and made available to the customer to monetize, and in some cases it is unclear when or if it will be technically feasible to achieve these benefits. As such, these value streams are essentially speculative and outside the scope of this discussion.

Both Sandia and EPRI identify two additional value streams for commercial, behind the meter storage that can be monetized today. These are reliability - providing back-up power in the case of an extended outage, including bridging power for uninterrupted service during an outage - and power quality - correction of power quality issues from the utility including short duration or

[5] "Electricity Energy Storage Technology Options", December 2010, Rastler, D.
[6] "Energy Storage For The Electric Grid: Benefits and Market Potential Assessment Guide", February 2010, Eyer J. and Corey, G.

"momentary" power outages. These additional value streams are only relevant to the battery-based systems, not the Ice Energy system.

For reliability service, at least 15 minutes of energy and possibly as much as an hour would need to be held "in reserve" at all times, since in the demand reduction application the expectation is that all available energy will be discharged each day. Additionally, the power output of the system would have to be equal to or greater than that required for at least "critical loads", which might impact the kW sizing of the system. While increasing the energy on board the system certainly would be expected to have a lower incremental cost than having an energy storage system solely for the purpose of back-up power, the value of this back-up capability cannot be double-counted. The EPRI and Sandia white papers document a wide range of estimates for the value of this benefit, from $47 - $978/kWh. At the lower end of this range the additional value is almost certainly less than the capital investment required to hold incremental energy in reserve. At the upper end, the incremental energy could improve the value proposition of the system substantially. These benefits are derived from several sources, primarily research into the economic impacts of outages on customers. The high end of the estimate ($978/kWh) is based on the avoided cost value of a 1-hour standalone UPS system, which are typically only used where even momentary outages are unacceptable and power quality is critical (e.g. data centers).

For power quality, little additional energy is needed but the system must be sized and configured to protect a set of critical loads. Provision of power quality services may or may not be possible while performing the primary demand reduction function of the system. In the EPRI and Sandia reports, there is a similarly broad range of estimates for the value of power quality – between $19 and $978/kWh (assuming a 1 hour system). Again, the higher number is the "avoided cost" for a stand-alone UPS system so it cannot be added to the reliability number. Therefore, $978/kWh (or /kW) can be viewed as the upper bound of allowable cost for the combination of reliability and power quality, assuming that the customer would be willing to make the alternate investment into a stand-alone UPS and the solution would provide identical functionality, in addition to demand charge reduction.

In both cases, some additional installation costs are anticipated. First, at a minimum the storage inverter would need to be capable of running in both a grid-tied and grid-independent mode, which may increase the cost of this component. The premise may also need to be electrically reconfigured with a dedicated load panel that is suitable for stand-alone (islanded) operation, and locked out from the utility.

What is most relevant in this case is the willingness of the customer to pay for incremental energy storage capacity and/or configuration to meet reliability and power quality goals. In the case of the customer in this study, each site was already equipped with natural gas fueled back-up generation, but was not equipped with a UPS or devices to correct power quality issues (such as harmonics or low power factor). This is likely typical for this class of big box retail customer. It is therefore clear that the "avoided cost" for standalone UPS or PQ correction systems is not a reasonable comparison. It also seems unlikely that a significant number of customers in this class have PQ issues aside from outright short-duration outages, since they are probably relatively insensitive to the quality of utility service. Therefore, in this brief treatment, the focus is on outages and in particular short term outages which could occur between loss of utility service and gen-set start. The Sandia report uses an estimate of $5/kW of avoided cost per outage, and 10 outages per year, to derive a value of $50/kW/yr and an associated NPV of $359/kW. While this seems like a reasonable "placeholder" value for additional benefit, the willingness to pay for this capability will certainly vary by customer.

For the purpose of discussion, then, we find that including these benefits could potentially increase the value of the original generalized system. For customers that are willing to pay for these additional services, the value could be estimated as $710/kW or $315/kWh, for a 2.25 hour system (with the additional energy held in reserve for the reliability service requirement).

How does this compare to installed costs for these systems? The EPRI white paper provides public cost data on energy storage solutions (including data presented originally in the Sandia paper) and is helpful in this assessment. The EPRI document covers two of the three technology types included in this project, Zn/Br Redox (ZBB) and Vanadium Redox (Prudent). The estimated installed costs published in this document are at large scale (50 MW) and for system with a generally higher energy to power ratio than considered here. Therefore while they can't be used directly, they could be considered as an optimistic and forward-looking proxy for pricing in smaller scale applications such as proposed here. These values, shown in the table below, are not necessarily representative of those disclosed by each vendor under NDA. The values shown for Ice Energy were provided by them for comparison purposes.

Technology	Benchmark Power	Benchmark Hours	$/kW	$/kWh
Zn/Br Redox	50 MW	5	$1450 - $1750	$290 - $350
V Redox	50 MW	5	$3100 - $3700	$620 - $740
Ice Energy[7]	8 kW	6	$2500 - $3000	$417 - $500
Ice Energy[8]	50MW	6	$1500 - $2200	$250 - 367

Table 4: EPRI Benchmark Costs

Comparing the value to these costs and to confidential installed cost data provided by the vendors, it is clear that all three systems must achieve significant cost reduction to profitably capture the currently available value streams in this application. Reduction in O&M costs may also be an important factor in meeting these goals. It is expected that the demonstration phase of this project will provide the vendors with an opportunity to address these challenges.

Each vendor does have a roadmap for cost reduction and/or improving the value of the technology (for instance by eliminating the PV inverter). If successfully executed, these roadmaps will help to close the gap between current installed costs and the value achieved in the application. In some cases, the vendors control the roadmap (e.g. manufacturing costs) while in others, achievable cost reductions may be lower than present expectations (e.g. the avoided cost of a separate PV inverter may be less than expected).

A related question is whether California's $2000/kW Self-Generation Incentive Program (SGIP) incentive is sufficient to achieve economic viability for these technologies in the application. For the electrochemical batteries, if the vendor's cost roadmaps are executed successfully and the technology is used in applications where reliability benefits can be monetized, this incentive is likely sufficient to achieve successful commercialization in this context. Ice Energy's technology appears to be viable at current installed costs, in this application given the incentive.

A final consideration related to the cost and value is related to the magnitude of cost savings. Even if the basic economic metrics are achieved, the total cost savings of the ~100 kW systems discussed in this application are calculated to be less than $10,000 per year and in some cases less than $5000

[7] Cost benchmark representative of installed costs for a single site (typically comprising ten or more units).
[8] Cost benchmark is representative of its utility scale projects where the capacity is purchased by the utility as a deferred or avoided cost alternative for generation, distribution, and reserve margin resource planning requirements.

annually. For a customer that could accommodate an energy storage system of this size, bills can approach $200,000 annually, even after the installation of a PV system – which, given the amount of roof space typically available, might provide an order of magnitude higher annual bill savings than storage. This is an issue because gaining the attention of corporate energy managers and other decision makers required to evaluate and approve relatively small projects can be difficult – particularly where the project economics and technologies are complex to understand. Bundling energy storage and PV projects together could be helpful to overcome this issue. This approach is commonly used with energy efficiency measures, where individual measures providing a significant ROI but small absolute benefit must be bundled into a larger project to gain traction. Increasing the size (kW) of the energy storage project would also help, though there are limitations to doing so. Principally, the limitation is that available demand offset may be limited. In the case of Ice Energy, available demand offset may be significantly lower than for the electrochemical technologies because the system only offsets HVAC loads. Other limiting factors, such as available space to accommodate the systems, may also be relevant.

Risk Factors Impacting Delivered Value

As discussed above, one important result of this modeling exercise is to illustrate that the value of the energy storage system changes significantly depending on the load and PV profiles, both across sites and year to year at the same site. It is worthwhile to discuss why this occurs in more detail.

Changes in load profile over time, or in unexpected weather conditions resulting in lower PV output (either momentarily or for more extended periods), are certainly two important components of risk. What has not been yet been discussed is that this risk could be exacerbated by the way in which systems are likely to be sized. Generally energy output from PV systems is modeled based on "typical" weather conditions, or a year of weather data that has a 50% probability of occurrence any given year. Energy generation will vary from year to year from this prediction – typically by 1-2% - but this variance increases further as the timeframe decreases. Therefore, PV output in a given 15 minute period in any given year could be much different from what was originally modeled. This is not generally an issue with PV systems because performance is rarely assessed over a period of less than a year, and because ultimately any underperformance in a given year would be compensated by over-performance in another year[9]. Additionally, in some cases there may not be usable load data for the facility, or it may only be available for a limited period. In this case it is likely that generic load shape data, such as eShapes, would be used. This is simply another area of risk that must ultimately be priced into the value that is presented to the customer.

Another significant risk factor in this application is technical in nature. If both the PV system and energy storage system are depended upon to achieve demand reduction – because the energy storage system is sized accordingly – this means that an extended period of unavailability of either device can cause the demand for the month to be set at, or close to native peak load levels. In the worst case, just a few minutes of unavailability in a month at the wrong time, for either system, can eliminate or significantly reduce all demand reduction for the month. For PV systems, while having one or more inverters go offline is infrequent, it does occur – most typically due to an event which trips the inverter offline and requires a reset. This typically results in a PV system outage lasting at least an hour. For this reason, it is typical to assume 98% availability (i.e. the system will produce 98% of the kWh it could have produced if operating perfectly), in PV performance predictions.

[9] Moreover, for commercial customers – and increasingly for residential customers as well – PV providers will often offer a performance guarantee which provides assurance that the system will perform as expected.

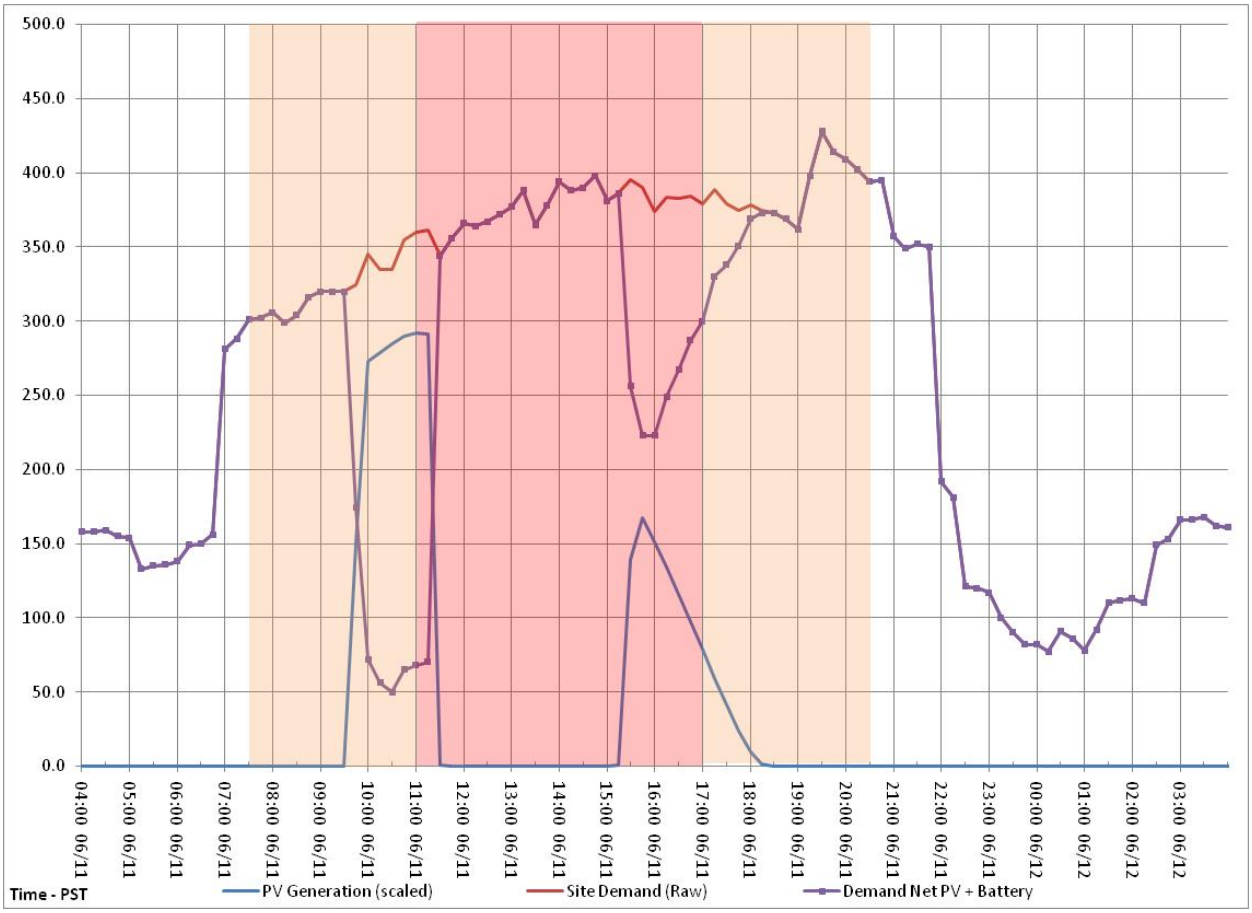

Figure 3: A 3.5 hour PV system outage during June peak. Such events, while infrequent, pose significant economic risk where demand charge reduction is the primary driver of value.

Because reliability and availability metrics are driven by the inverter, it is reasonable to assume that any inverter-based energy storage systems will have similar performance. PV industry experience has shown that inverter manufacturers in general, and new products in particular, have to be vetted carefully for reliability; inverters have long been known as the "Achilles heel" of PV systems and SunPower expends a great deal of effort to qualify this component of our systems. In this range of inverter sizes, there is currently no overlap between well-vetted PV inverters with a strong field track record and the inverters being used by storage vendors. In fact, the inverters used by storage providers are largely from a different set of manufacturers altogether, so this is a particularly important consideration. Experience from the PV industry does suggest that system uptime can be significantly improved when the system is serviced under an O&M program which includes real-time monitoring and management. While this does not eliminate the risk of system outages entirely, it appears that an active O&M service for both the PV and storage systems may be crucial to achieve the desired economic returns. Again, for PV systems where the consequence of any outage is primarily lost kWh, an occasional need to reset an inverter will not have an enormous economic impact, even if the outage lasts several hours. For an energy storage system or for the two systems combined, reliability of both systems becomes much more crucial.

It is also important to note that in some cases, inverter trips are both unavoidable and mandatory. For instance, in the case of a sufficiently deep voltage depression on the utility system – which, should it occur, is most likely under hot, heavy load conditions – all inverter based resources,

including energy storage and PV systems, are required to trip offline until voltage returns to the normal range and remain offline until the voltage at the point of interconnection is within normal range for at least five minutes. Such an unavoidable circumstance poses the risk of lost revenue because this tripping behavior is designed to occur prior to loss of utility service – so the net result of such a trip is a net demand spike.

Altogether, the optimized combination of PV and energy storage may present a very different risk profile to the customer - and in turn the developer - than either system alone. These risks of underperformance must be considered carefully, and dealt with at the outset either by offering a lower installed price, by increasing the amount of energy onboard, or some combination.

Other Factors

Aside from cost, the experience gained thus far in the pilot has been valuable in highlighting other factors which may affect a decision to install energy storage in this particular application.

The first, and perhaps most important is the ability of a site to accommodate a particular energy storage system. In the case of the flow battery systems, the physical space required to accommodate them is significant – ranging from 400 to 1000 square feet. For the sites originally selected for the pilot, all of which were located in shopping malls, this requirement constrained site availability. Of the five sites considered, only two were capable of accommodating equipment of this size and siting was only straightforward at one of the two locations. Another issue that was encountered related to permitting. In the course of this project, the team had an opportunity to meet with the authority having jurisdiction (AHJ) for one of the sites. The experience demonstrated that approval of such a system will be subject to a high level of scrutiny considering the innovative nature of these installations and therefore the lack of many permitting precedents. From a plan checker's perspective, what they are faced with approving is a large piece of equipment containing large quantities of liquid electrolyte, mechanical components, and high voltage electrical equipment, sited in a retail mall. Unsurprisingly, this raises a number of additional questions. These matters range from the expected – such as requiring a hazardous materials response plan – to the unexpected – such as considering requirements that the enclosure meet architectural standards such as having exterior stucco to match the mall's aesthetics. The storage vendor did an excellent job in being responsive to these questions and addressing them with the AHJ, but the experience highlighted that permitting, if not managed proactively, can become a significant project risk in terms of timeline, project team bandwidth, and potentially the final installed cost. Although the project has not yet proceeded to the point of gaining utility interconnection approval, it is likely that this process will still require significant effort to resolve all questions. Again, this scrutiny is expected for new and unusual projects and is likely to abate over time as successful installations are achieved. As has been seen in the PV industry, intensive and ongoing education of both AHJs and industry is necessary to achieve more streamlined permitting and avoid excessive "soft costs" that can hinder adoption of newer technologies.

The Ice Energy system encountered the fewest barriers. The systems are typically roof located; they are very similar to HVAC equipment that AHJs are familiar with; and they do not directly interact with the utility grid. Ice does have to perform an analysis to ensure that the roof meets structural requirements. In the case of PV systems, weight limitations are often encountered which in some cases constrain the maximum system size that can be accommodated. This issue would likely be exacerbated if additional rooftop equipment, like Ice Bears, is contemplated; in some cases however the Ice Bear units can be ground mounted. Another potential limitation is that Ice Bear units may

not be directly compatible with some existing HVAC equipment, possibly requiring modifications that can add cost. Overall, though, these potential barriers appear to be well managed by Ice Energy. One positive outcome of the experience gained to date with Ice was finding that the Ice Bear units could typically be located directly south of existing HVAC units and within their "shade pies", thus mitigating the risk that the equipment could restrict available roof space for the PV system.

Finally, the analysis performed for this report illustrates that it may be difficult for a stakeholder to confidently predict the value proposition of energy storage in this application. Selling this type of combined system will require development of expertise in the specifics of both PV and storage and how the systems interact relative to utility rate tariffs. Doing this across an organization and gearing up to serve customers over the system's life cycle will require an upfront investment that must be justified by a clear and sustained market opportunity.

As the project moves forward, these factors must be considered in the context of the relatively small economic benefit that is provided on an absolute basis and the opportunity cost involved in resolving them. Adoption may suffer if the customer acquisition, permitting, and installation process are not achievable with minimal transaction costs across a broad served available market.

Initial Conclusions & Recommendations

Near-Term Commercial Viability of Combining PV and Energy Storage

Based on the above preliminary analysis and careful consideration of input from the vendors and from recent 3rd party reports and white papers, there appear to be several challenges for the near-term commercial prospects for combining PV with the investigated electrochemical energy storage systems at these or similar sites. While the Ice Bear system does appear to achieve viable economics today when combined with PV, results indicate that doing so may not achieve the desired synergistic value proposition. However, Ice Energy indicates that a new release of their CoolData controller, which is a part of an Ice Bear unit, may allow for more dynamic interoperability with a PV system by controlling overall HVAC unit cycling behavior. In essence this combines storage with demand response.

It is important to note that this initial conclusion is predicated on presently available value streams and incentives, as well as current vendor cost structures. As each vendor drives down their cost roadmap and/or more opportunities to monetize energy storage benefits are made available to end customers, the economic incentives to combine PV and energy storage in these applications could improve significantly. This highlights the need for the CPUC to continue to consider the benefits of distributed energy storage and PV, particularly in combination, and work with stakeholders to improve the ability of customers to internalize those benefits.

Additionally and as is anticipated in the implementation phase of this project, these modeled results reaffirm the need to operate energy storage systems in the planned application conditions to gain a more comprehensive view of both economic and technical performance under real-world conditions, including validation of the vendor-provided input assumptions. The learnings from the modeling performed thus far provide important insight to the project participants into how the energy storage systems can be better sized and dispatched to achieve more optimal results.

Rate Design

It is important to note that many of the risk issues and other barriers identified here are a direct result of the structure of demand charges in PG&E territory, which are similar to those in other California utilities. Fundamentally, these demand charges pose a challenge to deploying energy storage behind the meter because of the difficulty to characterize the nonlinear, stochastic risk of “missing” any 15 minute period in a month.

Wide rate spreads on time of use energy charges, on the other hand, mitigate these issues. By simply providing an arbitrage opportunity, even if the full potential amount of energy is not shifted from the peak to the off-peak period, the penalty is directly proportional to “missed” arbitrage opportunity. This creates a risk profile that is very similar to that of PV, as discussed earlier. Of course, it would be possible to oversize a system both on power or energy relative to such a tariff, and building a smaller than possible system may result in somewhat higher costs, but this is also true of PV systems and is comparatively easy to manage.

Unfortunately, the existing TOU energy rates, for example PG&E’s A6, is not sufficient to address the issue. As an example, the maximum value that can be achieved under A6 for a 65% efficient device, at low risk, is 68% of the maximum value under E19. On a risk-priced basis, we could expect value to be approximately at parity between the two rate structures. Depending on the PV system size and customer use patterns, the PV economics also can be less attractive under A6 than

E19. This is partially due to relatively high off-peak rates, which also negatively impact storage economics – at a fixed rate spread, the higher the off-peak rate, the lower the effective rate spread.

Ultimately, the goal of pairing energy storage with PV behind the meter is to incentivize provision of firm capacity (in aggregate across the IOU) across the day and into the evening shoulder load hours. Given the disincentives that demand charges can create, it may make sense to instead create a short duration "super peak" energy rate which covers the late afternoon and early evening – for instance, 4-6 pm. This could be a voluntary "super-peak" version of existing TOU energy rates. If the rate spread is adequate, and the economics compelling compared to alternate rate options, this would provide a clear price signal for the deployment of high-value energy storage. It might be necessary to allow larger customers who are currently ineligible for TOU energy rates to participate in such a rate in order to drive a sufficiently large market.

Another approach which may be interesting to explore is that of providing a higher incentive for PV generated energy which is consumed on the premise, rather than net exported through the meter to the utility distribution system. A sufficient delta could incentivize energy storage, as well as other energy management approaches to achieve load and PV shape alignment. This approach has been implemented as part of the German feed-in tariff design, largely to facilitate high penetration of distributed PV while minimizing grid upgrade requirements.

Therefore, our second key recommendation relates to considering rate structure changes that would better incentivize combining PV with energy storage in order to achieve the goal of more effective demand reduction than either technology can offer alone. If implemented, these changes could significantly improve the economics of this type of project.

Demonstration Site Selection

With the withdrawal of the planned site host partner from this project, SunPower is prepared to engage with current customers to identify alternative pilot sites. Based on the experience to date, several attributes of these customers will be critical for project success:

- Forward-looking and empowered energy management team who can champion project implementation at the specific host site location.
- Agreement to proposed "no-cost EPC" contract provisions.
- A large ratio of PV generation to summer peak demand (ideally >85%); most likely in a hot inland climate.
- No issues with excessive PV system forced outage rates – customer managed under a SunPower O&M services agreement for duration of project.
- Sufficient physical space and siting flexibility; for Ice Energy, compatible HVAC equipment.
- Industrial customer / zoning preferred to avoid some permitting hurdles.

Appendix A – Report Requirements from SOW

The following was taken directly from the statement of work as agreed to between SunPower and Itron and serves as a reference for the purpose of this report.

Task 2: Establish Baseline

Purpose

The purpose of this task is to establish the baseline usage and load data in order to estimate the value proposition offered by the solar-storage system. Commensurate with this task and working closely with Target, SunPower and its partners will identify and select appropriate sites for each storage vendor and will use site load data, known PV output, energy storage data, and other operational parameters to generate the expected performance outcomes over time. The baseline report will provide the backdrop against which each ES system's actual performance will be measured over the course of this project.

Key Personnel: Carl Lenox, Rick Fioravanti

Subtask 2.1 Baseline Project Economics

Baseline economics will be identified through the development of survey for the energy storage manufacturer that covers data on all relevant technical performance parameters of their systems, including dispatch behavior. To these performance parameters, we will factor in at least 1 year of 15 minute interval net load data (and consumption data, if available) obtained from Target and/or PG&E for each of the demonstration sites. This data will be aggregated, error checked, and time-synchronized for each site. Additionally, we will analyze current rate tariffs and review potential alternate tariffs and their impacts on project economic valuations. Combining all related inputs, we will generate a baseline economic model for each site. This step also requires us to run, validate, and iterate the model multiple times in order to find maximum economic benefit for customer and associated break-even NPV for each energy storage device. A determination will be made for the best fit between net load profile and technology attributes, and will be used as a factor in deciding where each technology will be deployed.

Table of Technical Terms

Term	Definition
AC	Alternating Current
AHJ	Authority Having Jurisdiction
B/E	Break-Even
DC	Direct Current
EPC	Engineering, Procurement & Construction
EPRI	Electric Power Research Institute
ES	Energy Storage
eShapes	Itron database of load profiles for electricity and gas customers
HVAC	Heating, Ventilation and Air Conditioning
IRR	Internal Rate of Return
MACRS	Modified Accelerated Cost Recovery System (depreciation)
NDA	Non-Disclosure Agreement
NPV	Net Present Value
O&M	Operations and Maintenance
OAT	Outside Air Temperature
PQ	Power Quality
PV	Photovoltaic
RT efficiency	Round-trip efficiency
SGIP	Self-Generation Incentive Program
T&D	Transmission and Distribution
TOU	Time of Use
UPS	Uninterruptable Power Supply
V	Vanadium
W or kW	Watt or 1000 Watts
Wh	Watt-hour
Zn-Br	Zinc-Bromide