

California Solar Initiative

# RD&D

- Research, Development, Demonstration
- and Deployment Program

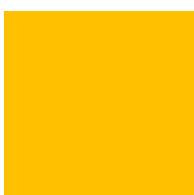


Final Project Report:

## PV Integrated Storage: Demonstrating Mutually Beneficial Utility-Customer Business Partnerships

Grantee:

Energy and Environmental  
Economics, Inc. (E3)



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# Preface

The goal of the California Solar Initiative (CSI) Research, Development, Demonstration, and Deployment (RD&D) Program is to foster a sustainable and self-supporting customer-sited solar market. To achieve this, the California Legislature authorized the California Public Utilities Commission (CPUC) to allocate **\$50 million** of the CSI budget to an RD&D program. Strategically, the RD&D program seeks to leverage cost-sharing funds from other state, federal and private research entities, and targets activities across these four stages:

- Grid integration, storage, and metering: 50-65%
- Production technologies: 10-25%
- Business development and deployment: 10-20%
- Integration of energy efficiency, demand response, and storage with photovoltaics (PV)

There are seven key principles that guide the CSI RD&D Program:

1. **Improve the economics of solar technologies** by reducing technology costs and increasing system performance;
2. **Focus on issues that directly benefit California**, and that may not be funded by others;
3. **Fill knowledge gaps** to enable successful, wide-scale deployment of solar distributed generation technologies;
4. **Overcome significant barriers** to technology adoption;
5. **Take advantage of California's wealth of data** from past, current, and future installations to fulfill the above;
6. **Provide bridge funding** to help promising solar technologies transition from a pre-commercial state to full commercial viability; and
7. **Support efforts to address the integration of distributed solar power into the grid** in order to maximize its value to California ratepayers.

For more information about the CSI RD&D Program, please visit the program web site at  
[www.calsolarresearch.ca.gov](http://www.calsolarresearch.ca.gov).

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# Abstract

This report describes the distribution grid impacts and economic benefits of behind-the-meter PV integrated energy storage deployed at residential customer sites in the Sacramento Municipal Utility District (SMUD). The novel contributions of this California Solar Initiative (CSI) funded demonstration project are: 1) directly dispatching customer owned distributed storage from a utility demand response management system (DRMS) with open automated demand response (Open ADR) protocols, 2) quantifying grid impacts of 34 Sunverge distributed energy storage systems over 17 events in 2015 using 1-minute interval data with participant and non-participant control groups, 3) quantifying the operational and distribution planning benefits of customer and utility dispatched PV integrated storage with powerflow (OpenDSS) and integrated distributed energy resources (iDER) models and 4) using these results to design utility sponsored programs that can incentivize retail customers to deploy energy storage with maximum net benefits for utilities and their ratepayers.

With support from the US Department of Energy and the California Energy Commission, Pacific Housing Incorporated (PHI) installed 34 Sunverge Solar Integration System (SIS) units at the innovative 2500 R Street zero net-energy community development in the Sacramento midtown district in 2013. Each residential unit has 2.25 kW of PV and a 4.5 kW/11.7 kWh energy storage system that charged only from PV for this demonstration, though it is technically feasible to charge from the grid. A portion of the storage is reserved to provide backup power to a customer's critical loads in case of a grid outage, and the remainder is available to discharge during on-peak load hours.

In 2015, 17 customers enrolled in the SMUD Time-of-Use Critical Peak Pricing (TOU-CPP). On CPP event days, 1.8 kWh of the battery was reserved for customer backup power leaving 8.2 kWh available for dispatch over a 3 hour period. For nine critical peak pricing (CPP) events from June to September the combined solar and storage systems provided a an average of 2.2 kW and 6.5 kWh of load reduction (80% of the available energy storage). In October and November, SMUD initiated eight demonstration events with varying levels of advanced notice and duration. For these events, 3.5 kWh of the battery was reserved for backup power, leaving 6.5 kWh available for dispatch. The average load reduction across 20 participants was 1.4 kW and 5.6 kWh (88% of the available energy storage).

OpenDSS modeling of SMUD's Waterman/Grant Line feeder with Rocky Mountain's EDGE tool found that PV both with and without storage provided similar operational benefits, primarily in reducing the hours of capacitor bank operation. Integrated Distributed Energy Resource modeling performed by Energy and Environmental Economics for SMUD's Jackson/Sunrise feeders finds that energy storage dispatched for utility and customer benefits provides local distribution deferral benefits of \$148/kW-yr. (vs. no deferral value when dispatched for customer benefits only). For the conditions and locations included in this study, the total grid benefits of distributed energy storage are \$251/kW-yr. In a local capacity constrained area such as the LA Basins, the total value could be \$433/kW-yr. or higher.

With a high distribution deferral value, the \$251/kW-yr. in total benefits when dispatched for utility and customer benefits (with a reservation for customer backup power) are \$182/kW-yr. higher than when dispatched for customer benefit only, an increase of nearly 2.5 times. A program including dispatch for utility as well as customer benefits or a dynamic Full Value Tariff is technically feasible and potentially attractive for customers. Furthermore, such a program provides significantly more value to the utility and its ratepayers than programs that provide incentives for installing storage that is dispatched for the customer's benefit only.

# 1 Executive Summary

## 1.1 Policy Context

Interest in distributed energy resources (DER) broadly and photovoltaic (PV) and energy storage in particular are being driven by a number of California's policy and market transformation initiatives seeking to increase deployment of renewable generation and reduce greenhouse gas (GHG) emissions. Governor Brown signed SB 350 in October 2015, increasing California's renewable portfolio standard to 50% by 2030. California AB 327 requires California investor owned utilities (IOUs) to consider DERs as part of their distribution system planning process for deferment of traditional infrastructure projects and the California Public Utilities Commission (CPUC) has initiated Integrated Distributed Energy Resource (IDER) and utility distribution resource planning (DRP) proceedings.<sup>1</sup> In addition, California AB 2514 requires all three CA IOUs to procure a combined storage capacity of 1.325 GW by 2020, of which 200 MW must be customer sited.

Customer adoption of behind-the-meter (BTM) PV is also expected to continue to grow. In January 2016, the California Public Utilities Commission (CPUC) issued a decision continuing net-energy metering (NEM). With the extension of NEM and the Federal Investment Tax Credit (ITC) and declining cost of PV, the NEM Public Tool developed by Energy and Environmental Economics for the CPUC projects forecasts 17 to 21 gigawatts (GW) of BTM PV adoption by 2025 (as compared to 3.8 GW today). (Energy and Environmental Economics, 2015).

Energy storage is one of several strategies that can support regional and local utility grids as penetration of intermittent renewable generation increases. Storage can also provide peak load reductions in locally constrained areas where siting of new generation and transmission assets is especially difficult. For example, Southern California Edison (SCE) acquired more than 250 MW of energy storage to meet local capacity requirements in the Western LA Basin and Moorpark sub-areas.

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<sup>1</sup> R. 14-10-003 and R. 14-08-013

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The goals of the California Solar Initiative Research, Development, Demonstration and Deployment Program (CSI RD&D) is to help build a sustainable and self-supporting industry for customer-sited solar in California. This CSI RD&D-funded project supports this goal by demonstrating how PV integrated storage can be dispatched for utility and customer benefits to greater effect than either technology alone.

## 1.2 Project Objectives

This project is designed to demonstrate and quantify the value that BTM PV integrated storage can provide for the utility and its ratepayers. The objectives of this project are to:

- + Translate demonstration of high penetration distributed PV integration into tangible policy and planning recommendations
- + Document performance with high resolution metering of PV production, customer loads, energy storage dispatch
- + Demonstrate dispatch of customer-owned energy storage for customer and grid benefits with a utility's Demand Response Management System (DRMS)
- + Develop robust estimates for local distribution system operational benefits, supported by OpenDSS power flow modeling
- + Overcoming near-term cost barriers by demonstrating simultaneous customer and utility benefits for BTM energy storage with iDER modeling
- + Develop tariffs and incentives, program designs and customer outreach strategies for BTM energy storage

## 1.3 Project Approach

In 2009, the Sacramento Municipal Utilities District (SMUD) received a Smart Grid Investment Grant from the US Department of Energy (DOE) to help fund SmartSacramento, one of the Nation's most comprehensive smart grid rollouts (Section 3.1). As part of that project, SMUD partnered with 2500 R Group, LLC, a joint venture between Sunverge and Pacific Housing, to implement the 2500 R Midtown smart home demonstration. 2500 R Midtown is a 34-unit, single family development in midtown Sacramento located at 2500 R Street. The development consists of 28 two-story houses and six three-story houses, ranging in size from 1,251 sqft. to 1,828 sqft. With DOE Advance Research Projects Agency – Energy (ARPA-E) funding, SMUD and Sunverge conducted a demonstration project dispatching SIS units

to reduce peak loads (Section 3.2). This CSI RD&D funded project extends the study of the 34 SIS units at 2500 R Midtown with a 2015 demonstration.

Each of the development's 34 homes contains its own Sunverge Solar Integration System (SIS) – a 2.25 kW PV system integrated with a 4.5kW/11.7 kWh battery. The batteries have 8.8 kWh (1.2 kWh additional is reserved for backup) of total usable battery capacity, providing about 2 hours of power at maximum continuous output. On regular TOU days, 3.5 kWh of the battery is reserved for customer backup power. The backup power reservation is reduced to 1.8 kWh during Critical Peak Pricing (CPP) event days. Though SIS units can charge from PV generation and the utility grid, the SIS units were charged only from PV during the demonstration project.

The 2015 demonstration focused on using SMUD's DRMS to dispatch the existing SIS units at 2500 R Midtown (Section 3.3). The 2015 Demonstration includes:

- Nine Critical Peak Pricing (CPP) events in June-September for 17 customers enrolled in SMUD's TOU-CPP rate. Customers were sent day-ahead e-mail and text notifications by SMUD.
- Eight additional test demand response (DR) events in October-November with 20 customers' SIS units dispatched by the Sunverge Software Control Platform as an automated response to SMUD's DRMS demand response event signals. These tests were of varying durations and advanced notification times.

The project team defined and evaluated energy storage use cases providing backup power and bill reduction for the customer and system peak load reduction, distribution peak load reduction and predictable dispatch for the utility grid (Section 3.4). To implement these use cases, Sunverge worked with SMUD to integrate dispatch of SIS units with SMUD's Lockheed-Martin SEEload Demand Response Management System (DRMS) via Open Automated Demand Response 2.0a (OpenADR 2.0a) protocol (Section 3.5). Comparing participant and non-participant groups, Energy Solutions quantified the performance distributed energy storage for the use cases studies using 1 minute meter data provided by Sunverge (Section 4.1).

The Rocky Mountain Institute (RMI) worked with SMUD to export distribution system models from Synergi to OpenDSS and model three feeders on SMUD's Waterman-Grantline substation (Section 4.2) RMI used the Electricity Distribution Grid Evaluator (EDGE) model, a MATLAB-based simulation tool, for evaluating

and optimizing the net value proposition of DERs. With the distribution system operations module of the EDGE model, RMI performed quasi-static time series power flow simulations of circuit operations for a full year at 15-minute intervals. RMI modeled the three feeders with current and high penetrations of PV and with and without PV integrated energy storage.

Using CPUC adopted DER avoided cost and cost-benefit methods (Section 5.1), the project participants designed and conducted a simulation based case study for SMUD's Jackson-Sunrise and Waterman-Grantline feeders (Section 5.2). System and local distribution costs and benefits benefits from customer adoption of SIS units were quantified using E3's Integrated Distributed Energy Resource Model (iDER) (Section 5.3). The distribution network investment deferral and operational benefits of PV with and without integrated storage are investigated in detail for the two feeders (Sections 5.4). We then performed cost-benefit analysis to quantify the net benefits of PV integrated storage from customer, regional and utility ratepayer perspectives (Sections 5.5 – 5.6) . E3 analyzed the benefits under three cases: PV only, PV integrated storage for customer benefits, and PV integrated storage for utility benefits. Finally, we calculated the maximum ratepayer neutral incentive that could be paid by utilities to encourage the dispatch of energy storage for utility as well as customer benefits (Section 5.7). All cost and benefit results in this report are presented in \$/kW-yr. on the basis of rated kW output of the Sunverge SIS units, which is 4.5kW nominally and 6kW when considering the larger new model.

Energy Solutions surveyed utility customer focused energy storage programs and worked with SMUD to develop program design recommendations (Section 6). We summarized existing storage incentive programs (Section 6.1) and described progam design considerations and components (Sections 6.2 – 6.4). We then described three example programs, including utility sponsored, midstream focused and a dynamic Full Value Tariff (Section 6.5).

The conclusions and recommendations from our study are presented in Section 7.

## 1.4 Project Outcomes

The project team successfully completed the integration of SMUD's SEEload DRMS with Sunverge SIS Cloud using OpenADR 2.0a and monitored the performance of the SIS units over 17 events in 2015. The DRMS integration, load impacts and RMI EDGE modeling outcomes are described below. The following

Section 1.5 Ratepayer Benefits and Program Design summarizes the cost-benefit results and program design recommendations.

#### 1.4.1 DRMS INTEGRATION

SMUD's DRMS, Lockheed-Martin's SEELoad, does not currently have built-in capability to integrate with Sunverge's SIS Control Platform to provide distribution level monitoring and controls to automate dispatch of distributed energy storage resources. SMUD is planning a DRMS upgrade that may not be backward compatible with the existing energy storage module in SEELoad. For these reasons, SMUD elected not to invest resources into validating and testing with the existing energy storage module in SEELoad.

SMUD and other utilities in California have been using OpenADR as a standard protocol to dispatch demand response resources. SMUD and Sunverge determined that using OpenADR to dispatch SIS units would be the most expedient path to demonstrating DRMS integration to dispatch of customer owned energy storage in 2015 (OpenADR Alliance, 2012). SMUD implemented OpenADR 2.0a, the 'simple' version of the OpenADR protocols.<sup>2</sup> OpenADR is a comparatively simple protocol for utilities to easily automate communication with third party distributed energy storage system (DESS) control software. Given SMUD's prior experience using OpenADR, implementation was relatively straightforward.

SMUD and Sunverge successfully completed eight test demand response events in October-November 2015 using OpenADR, with varying durations and advance notification signals, including day-ahead and day-of, two events on the same day, and multiple notifications given on the same day.

With the simpler OpenADR 2.0a, the Payload field that defines a use case can only be set to four numbers (0-3). This limits the SIS units to only four types of response, which must be determined prior to sending the event signal. Although the SIS units collect data at several metered points, OpenADR 2.0a does not allow feedback regarding performance to be sent back to the utility. This limits the functionality and use cases that can be implemented. Integration of the DRMS with the more advanced OpenADR 2.0b version or directly with a storage vendor's application programming interface (API) would enable more dynamic

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<sup>2</sup> The OpenADR 2.0 profile specification is divided into two parts. Profile A: Is designed for resource-constrained, low-end embedded devices that can support basic DR services and markets. Profile A is well suited to support standard DR programs. Profile B: Is designed for high-end embedded devices that can support most DR services and markets. Profile B includes a flexible reporting mechanism for past, current and future data reports.

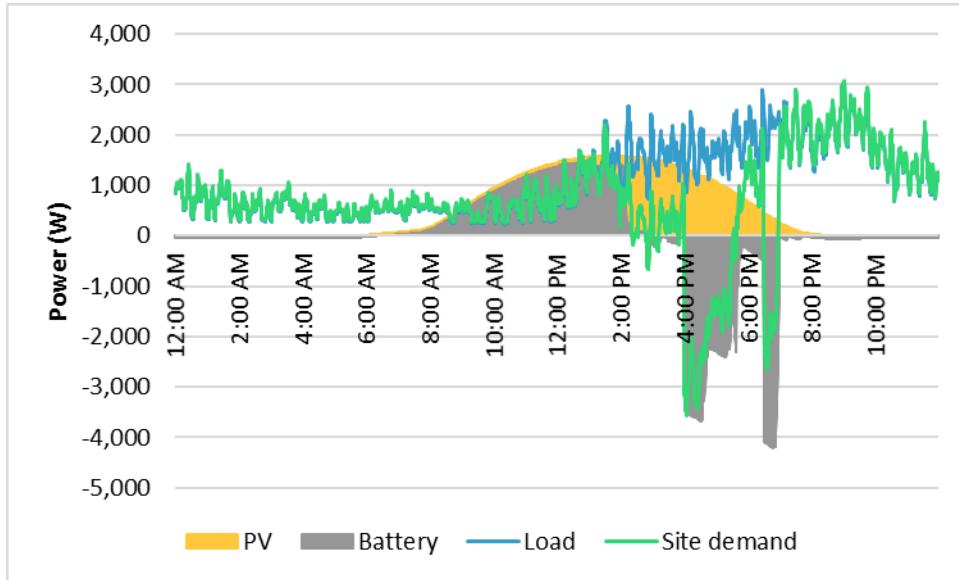
response than is feasible with OpenADR 2.0a. For example, the DRMS could request a specific MW dispatch, and Sunverge could communicate back whether this capacity is available and dispatch available resources accordingly.

#### **1.4.2 2015 DEMONSTRATION LOAD IMPACTS**

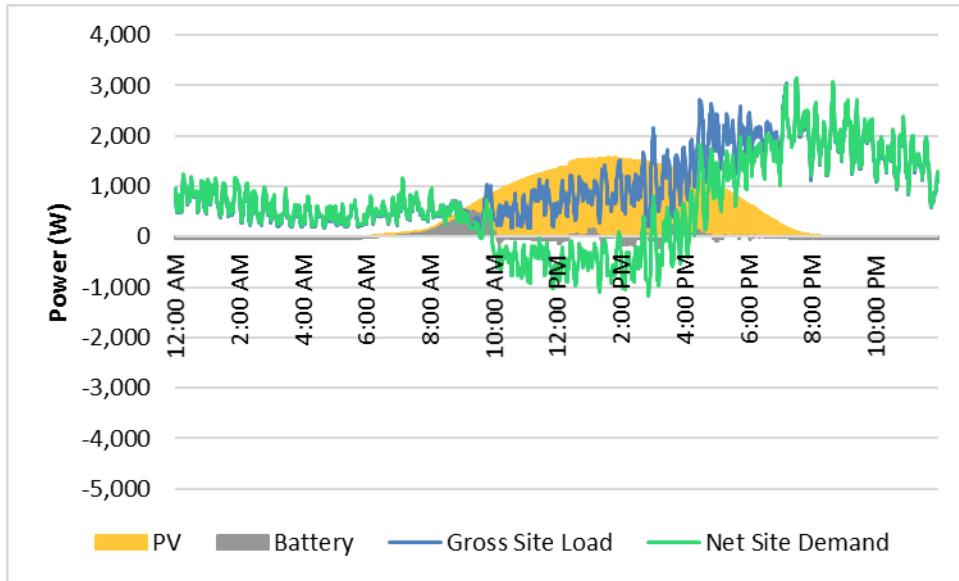
Sunverge provided minute interval data on gross household load, PV production, storage charging and discharging, and net site import or export at the point of interconnection with the utility grid. We evaluated the impacts of SIS dispatch on net site load for nine DR events during SMUD's summer TOU-CPP program and for eight simulated DR events in the fall DRMS demonstration tests. For our baseline, we calculated the net site load based on PV production and gross household load, as if no energy storage system was installed. For our impacts, we calculated the reduction (or increase) in net site load with the SIS units for both non-participating customers and for participating customers that have opted-in to SMUD's summer TOU-CPP rate. On CPP event days, the customer backup power reservation is reduced from 3.5kWh to 1.8kWh capacity, leaving 8.2 kWh available for dispatch. For the Summer TOU-CPP events, non-participants exhibited slight load increases relative to stand-alone PV, though within the margin of metering error. This can be attributed in part to stand-by load of the SIS units.

The storage dispatch and net site demand for participating and non-participating customers are illustrated in Figure 1-1 and Figure 1-2 for the TOU-CPP event on June 26<sup>th</sup>, 2015. The charts show the average of 1-minute meter data for all the customers either participating or not participating in SMUD's TOU-CPP program. The participants charge the batteries from PV generation until the batteries are full at around 2 pm in the afternoon. The storage is then discharged at the start of the CPP event at 4 pm. Note that irregularities in the dispatch of storage were addressed in subsequent programming updates discussed further in Section 3.5. The non-participants operate under a standard volumetric rate without defined TOU periods. The battery tops off with generation from solar PV before 10 am, but thereafter the solar generation is providing maximum value by serving customer loads and exporting to the grid, providing bill credit at retail rates through net energy metering.

**Figure 1-1. Average TOU-CPP Program Participant Power Flows on June, 26<sup>th</sup> 2015.**



**Figure 1-2. Average Non-Participant Power Flows on June, 26<sup>th</sup> 2015.**



During the summer TOU-CPP events, participants provided an average load decrease ranging from 1.8 to 2.4 kW and 5.5 – 7.2 kWh over 3 hours from 4 – 7 pm (Table 1-1). Over the nine events, the average load reduction is 2.2 kW and 6.5 kWh (79% of the available energy storage). For the Fall DR events, SMUD initiated 8 demonstration events with varying levels of advance notice and duration. For these events, 3.5kWh of the battery is reserved for customer backup power, leaving 6.5 kWh available for dispatch.

Load reductions ranged from an average of 0.6 – 1.7 kW and 2.7 – 5.2 kWh.<sup>3</sup> The average load reduction across 20 participants was 1.4 kW and 5.6 kWh (86% of the available energy storage). On all event days but one, the PV generation available to charge the battery exceeded the available battery capacity.

**Table 1-1. Average Battery Discharge Across All Events**

<b>Participation</b>	<b>Summer TOU CPP</b>		<b>Fall OpenADR Events</b>	
	kW	kWh	kW	kWh
Non-participants	(0.11)	(0.31)	0.29	1.10
Participants	2.17	6.50	1.38	5.64
Difference	2.27	6.82	1.09	4.54
Available Battery Capacity		8.20		6.50
Participant kWh discharged as % of Available Battery Capacity		79%		86%

#### **1.4.3 GRIDEDGE DISTRIBUTION MODELING FOR SMUD'S WATERMAN-GANTLINE FEEDERS**

Although Synergi provides capability to export models to OpenDSS format, extensive review and manual modifications were required to validate that OpenDSS models were accurately calibrated. This limited our distribution operations modeling to a single feeder on SMUD's system. The only mechanically-switched equipment on the Waterman-Grantline circuit are three line capacitors, limiting the operational benefits that could be shown with distributed energy storage. The PV systems did reduce annual energy losses by 0.5-1.2% and reduced the hours of capacity switching operation by 50%. However these results were achieved with PV alone, and adding energy storage did not significantly increase the benefits to this feeder. RMI uses a hypothetical case to demonstrate that energy storage could resolve under-voltage issues if they were present and defer a line voltage regulator for a benefit of \$84/kW-yr.

## **1.5 Ratepayer Benefits and Program Design**

### **1.5.1 COST-BENEFIT ANALYSIS**

We perform a cost-benefit analysis using E3's Integrated Distributed Energy Resource (iDER) model. The avoided costs have over a 10-yr. procedural history in evaluating the cost-effectiveness of distributed

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<sup>3</sup> Excluding the one hour, 10 minute ahead notification event, which provided 0.6 kWh of discharge.

energy resources at the California Public Utility Commission (CPUC). E3's method provided values in the middle of other published Value of Solar studies.

Table 1-2 provides a brief overview of the avoided costs of supplying marginal energy from the utility's perspective. These costs are avoided if energy consumption is reduced or DERs produce energy and increased if consumption is increased or DERs consume energy, and can have time varying values.

**Table 1-2. Utility's Avoided Cost of Energy Components.**

Component	Description
Avoided Energy Cost	Hourly wholesale value of energy
Avoided Generation Capacity Cost	The avoided cost of building new generation capacity to meet system peak loads
Avoided Ancillary Services Cost	The avoided marginal costs of providing system operations and reserves for electricity grid reliability, assumed to be 1% of energy cost
Avoided Losses	The avoided cost of increased resistive transmission and distribution losses due to an increase in end users load
Avoided Emissions	The avoided abatement cost of carbon dioxide (CO <sub>2</sub> ), nitric oxide, and nitrogen dioxide (NO <sub>x</sub> ) emissions associated with the marginal generating resource
Avoided RPS	The avoided purchases of required renewable generation at above-market prices required to meet a renewable portfolio standard
Distribution Deferral Value	The time value of money when the peak distribution network load is reduced, and an investment in distribution capacity can be deferred
Distribution Operations	Avoided mechanical wear on distribution equipment such as tap changing transformers or switching capacitors

Table 1-3 describes the costs and benefits that a utility customer faces when deciding to adopt a DER such as the SIS.

**Table 1-3. DER Adopting Customer's Costs and Benefits.**

Component	Description
Federal Tax Credits	Federal Solar Investment Tax Credit
SGIP Incentive	California Self Generation Incentive Program payment from a utility company to a distributed generation adopting customer
Utility Bill Savings	Customer's retail electricity bill savings during the useful life of a DER
Ancillary Services Revenue	Revenue earned from DER participation in CAISO ancillary services markets that is passed on to the customer
Customer Reliability Value	Reliability value that an SIS adopting customer gains from using the SIS as an uninterruptable power supply (UPS) during a blackout
Total Storage System Cost	Purchase cost of the entire SIS battery energy storage system
Total PV Cost	Purchase cost of rooftop PV associated with the SIS unit.

Though we list it here, our cost-test results do not include customer reliability value. This is because there is an extremely wide range of customer value of service or interruption costs in the available literature. We do separately calculate a reliability benefit for using a portion of the battery (2 hours of duration) for customer reliability ranging from \$1.20/kW-yr. for residential customers to \$126/kW-yr. for commercial customers in Section 5.6.9. The SIS units studied here can provide 2 hours of storage at a maximum output of 4.5 kW.

Table 1-4 shows the sizing and cost values used for this study. Solar PV costs are taken from E3's NEM Successor Public Tool and energy storage system costs were provided by Sunverge. The 2500 R SIS model is used in the base case of this study and represents the units installed in the 2500 R Street demonstration. The New SIS model represents a potential future Sunverge design. SIS Storage System costs do not include installation, permitting, or initialization costs.

**Table 1-4. SIS Equipment Cost and Sizing.**

SIS Model	Solar PV Cost (\$)	Storage System Cost (\$)	Total SIS Cost (\$)	Solar Size (kW)	Max Battery Power (kW)	Max Battery Energy (kWh)
2500 R	8,899	11,000	19,899	2.25	4.5	11.64
New	17,798	15,000	32,798	2.25 <sup>4</sup>	6	19.64

### 1.5.2 LOCAL DISTRIBUTION BENEFITS OF SOLAR INTEGRATED STORAGE

SMUD identified two substations as potential distribution investment deferral candidates based on SMUD's 2015 Distribution Investment Plan. The Jackson-Sunrise requires an upgrade of a 6.25 MVA transformer to the next size of 12.5 MVA in 2017 due to a large customer moving from 69 kV to 12 kV service. The Waterman-Grantline substation has a single 20 MVA transformer serving three feeders whose combined peak load is expected to grow to 33 MVA in the next 10 years, requiring a second 20 MVA transformer in 2020-2021.

We model the SIS units on each feeder, assuming the battery has an 85% maximum depth of discharge. Although SIS units are rated for a 20 year life, annualized costs and benefits are calculated using a 15 year modeling horizon. We compare three scenarios: stand-alone PV without energy storage, customer dispatched storage to maximize bill reductions and utility dispatched storage to maximize utility benefits.<sup>5</sup> Cost-tests representing regional, ratepayer and participant perspectives are calculated for each scenario (described further below).

PV alone does not defer the Jackson-Sunrise upgrade, because the feeder load peaks late in the day after PV generation has declined. However, 34 SIS units with utility dispatch can defer the upgrade for 5 years. The annualized benefit for a five-yr. deferral is \$148/kW-Yr for each kW of SIS energy storage.

On the Waterman-Grantline feeders, one year of deferral is realized by PV without storage, and adding storage does not increase the years of deferral or total deferral value to the utility. Because of the rapid load growth on this part of the distribution network, over 1,000 SIS units with PV would be required to achieve more than 1 year of deferral. Avoided capacitor replacement cost due to lower mechanical

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<sup>4</sup>The size of the PV array can technically be sized up to 7kW, but depends on the configuration at the site.

<sup>5</sup>Note that the customer and utility scenarios represent different perspectives, but the customer and utility benefits are additive.

stresses was also analyzed for Waterman-Grantline. The value ranged from \$1.19/kW-yr. to \$10.40/kW-yr., depending on assumptions, but was the same whether customers adopted only PV or PV with SIS units.

### 1.5.3 COST-EFFECTIVENESS TEST RESULTS

The cost-effectiveness of SIS adoption was evaluated for the participant cost test (PCT), the total resource cost test (TRC), and the ratepayer impact measure cost test (RIM) perspectives using the iDER model. Table 1-5 shows how the cost and benefit components are used to compute the cost tests.

**Table 1-5. Costs and Benefits from Each Cost Test Perspective.**

Benefit and Cost Component	TRC	RIM	PCT
Federal Tax Credits	+		+
SGIP Incentive		-	+
Utility Bill Savings		-	+
Ancillary Services Revenue	+		+
UPS Reliability Value	+		+
Total Battery Cost	-		-
Total PV Cost	-		-
Distribution Deferral Value	+	+	
Avoided Energy Cost	+	+	
Avoided Generation Capacity Cost	+	+	
Avoided Emissions Cost	+	+	
Avoided Losses Cost	+	+	
Avoided Ancillary Services Cost	+	+	
Avoided RPS Cost	+	+	
Avoided Capacitor Operation Costs	+	+	

Figure 1-3 shows the PCT results for SIS adoption at both distribution network locations and under utility and customer dispatch. The participant costs include the full cost of the PV and storage systems. The benefits include the federal tax incentive, the California SGIP incentive, and the customer bill savings. The

results show a net PCT cost in all 4 situations. Utility bill savings are smaller under utility dispatch than under customer dispatch. The feeder on which the storage is located does not effect on PCT results under customer dispatch and has very little effect on PCT results under utility dispatch.

Note that these benefits do not include the value of customer reliability because of the wide range of values in available literature. We do separately calculate a reliability benefit for SIS units under utility dispatch that ranges from \$1.20/kW-yr. for residential customers to \$126/kW-yr. for commercial customers. Many early adopters of energy storage are clearly willing to pay well over \$100/kW-yr. for an energy storage device whose primary benefit is providing backup power.

**Figure 1-3. Base Case PCT Results.**

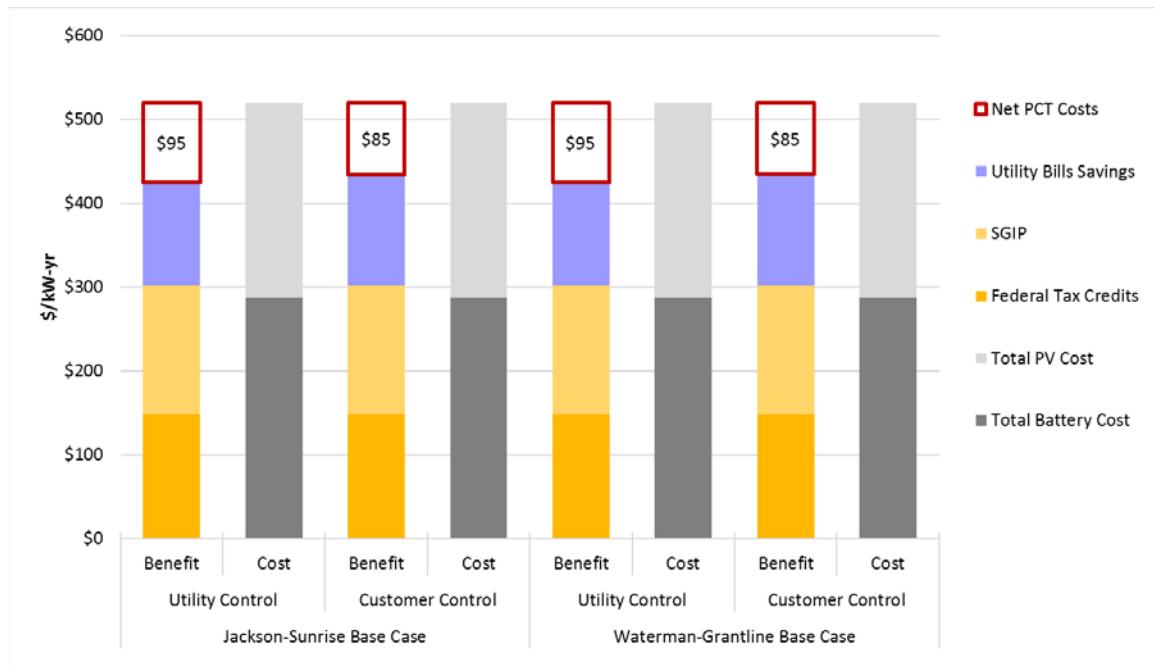


Figure 1-4 shows the TRC for SIS adoption at both distribution network locations and under both utility and customer dispatch. The TRC benefits include the federal investment tax credit. All cases show a net TRC cost. TRC benefits are larger under utility dispatch than under customer dispatch. On the Jackson-Sunrise feeders, there is no distribution deferral value under customer dispatch but \$148/kW-yr. of distribution deferral value under utility dispatch. The SIS does earn some distribution deferral value on the Waterman-Grantline feeders under customer dispatch, but not as much as when under utility dispatch. SIS adoption on the Jackson-Sunrise feeders has a net TRC cost \$58/kW-yr. lower than adoption on the Waterman-Grantline feeders mainly due to differences in distribution deferral value. On the

Jackson-Sunrise Feeders with the higher deferral value dispatching storage for utility and customer benefits increases the total TRC benefits from just over \$200/kW-yr. to \$400/kW-yr.

**Figure 1-4. Base Case TRC Results.**

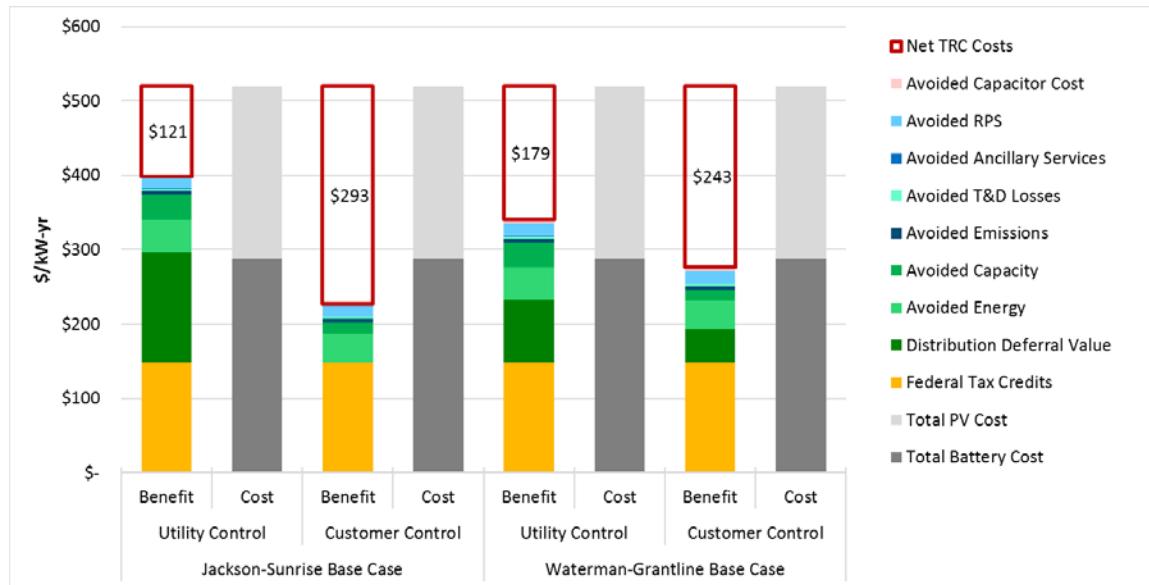


Figure 1-5 shows the RIM cost test results for SIS adoption at both distribution network locations and under both utility and customer dispatch. Unlike the TRC, the RIM benefits do not include the Federal investment tax credit. In all cases, there is a net RIM cost, meaning SIS adopting customers shift costs that must be borne by other non-participating ratepayers. The RIM cost is lowest under utility dispatch and on the Jackson-Sunrise feeders, the case where the distribution deferral value is greatest. Lower bill savings and greater distribution deferral value result in a smaller RIM cost under utility dispatch than under customer dispatch. Note the significant increase in benefits with dispatch for utility and customer benefits on the Jackson-Sunrise feeders, from \$75 to \$250/kW-yr.

**Figure 1-5. Base Case RIM Results.**

Table 1-6 summarizes the main cost-effectiveness results from the sensitivities studied. The studied scenarios are defined in Section 5.2.1. For each sensitivity, the net cost or benefit of each cost test is provided, with net costs shown in red. The PCT results are given assuming customer-benefiting dispatch, while the others are shown assuming utility-benefiting dispatch. SIS adoption generally results in a net cost from all cost effectiveness perspectives. The only scenario where customers would find SIS adoption to be cost effective is under the PG&E TOU rate. The only scenario where there is a TRC benefit from SIS adoption is when generation capacity is valued at \$250/kW-yr. SIS adoption benefits ratepayers without SIS units in the large SIS units, PG&E demand charge rate, and high capacity value sensitivities. When the SIS unit is under customer dispatch, the positive RIM and TRC benefits become costs.

**Table 1-6. Sensitivity Case Cost Tests (\$/kW-yr.).**

Case	Feeder	RIM	TRC	PCT
<b>Base Case</b>	<b>JS</b>	<b>-\$26</b>	<b>-\$121</b>	<b>-\$85</b>
	<b>WG</b>	<b>-84</b>	<b>-179</b>	<b>-85</b>
<b>High DER</b>	<b>JS</b>	<b>-33</b>	<b>-128</b>	<b>-85</b>
	<b>WG</b>	<b>-127</b>	<b>-223</b>	<b>-85</b>
<b>TOU + CPP</b>	<b>JS</b>	<b>-14</b>	<b>-121</b>	<b>-66</b>
<b>Larger SIS Units</b>	<b>JS</b>	<b>15</b>	<b>-70</b>	<b>-79</b>
<b>Ancillary Services</b>	<b>JS</b>	<b>-24</b>	<b>-95</b>	<b>-24</b>
<b>2016 SMUD TOU</b>	<b>JS</b>	<b>-40</b>	<b>-121</b>	<b>-60</b>
<b>PG&amp;E TOU Rate<sup>6</sup></b>	<b>JS</b>	<b>-117</b>	<b>-121</b>	<b>9</b>
<b>PG&amp;E Demand Charge Rate<sup>7</sup></b>	<b>JS</b>	<b>-86</b>	<b>-121</b>	<b>-34</b>
<b>\$250/kW-yr. Capacity Value</b>	<b>JS</b>	<b>156</b>	<b>61</b>	<b>-85</b>

Cost-effectiveness tests were also performed for the case of customers adopting only solar PV and not an SIS unit. Table 1-7 shows how the different cost tests compare for the adoption of SIS units instead of only adopting solar PV of the same size. A green cell with a plus sign indicates that cost-effectiveness result improved when customers adopt SIS units instead of only adopting solar PV. A red cell with a minus sign indicates that the cost-effectiveness result worsened by moving from solar PV only to an SIS unit. The RIM and TRC are compared with utility dispatch of SIS units, while the PCT is compared under customer dispatch of SIS units. On the Jackson-Sunrise feeders, SIS unit adoption has a better RIM result than solar PV alone. The TRC improves with SIS adoption in the scenarios where SIS units are larger and where SIS units can offer ancillary services into the CAISO market. The PCT improves under SMUD's TOU + CPP retail

<sup>6</sup> PG&E E-TOU Rate<sup>7</sup> PG&E A-10 Rate

tariff, under PG&E's A-10 retail tariff with a demand charge, and when SIS units can offer ancillary services to the CAISO market.

**Table 1-7. Comparison of PV Only and SIS Cost-Effectiveness.**

Case	Feeder	RIM	TRC	PCT
<b>Base Case</b>	JS	+	-	-
	WG	-	-	-
<b>High DER</b>	JS	+	-	-
	WG	-	-	-
<b>TOU + CPP</b>	JS	+	-	+
<b>Larger SIS Units</b>	JS	+	+	-
<b>Ancillary Services</b>	JS	+	+	+
<b>2016 SMUD TOU</b>	JS	+	-	-
<b>PG&amp;E TOU Rate</b>	JS	+	-	-
<b>PG&amp;E Demand Charge Rate</b>	JS	+	-	+
<b>\$250/kW-yr. Capacity Value</b>	JS	+	+	-

In addition to the cost tests, we calculated the largest possible incentives that could be given to SIS adopting customers without increasing costs to other ratepayers. Assuming utility dispatch of SIS units, Table 1-8 lists the value of utility benefits and customer bill savings created by SIS adoption. The difference between the utility benefits and customer bill savings is the maximum incentive that can be given by the utility to SIS adopting customers without shifting costs to customers without SIS units. Currently, SIS adopting customers are eligible for the California SGIP, which has a levelized value of \$154/kW-yr. There are three sensitivity cases where the maximum ratepayer neutral incentive is greater than the SGIP incentive: with larger SIS units, under the PG&E Demand Charge Rate (A-10), and when generation

capacity has a value of \$250/kW-yr. The rightmost column in Table 1-8 shows the PCT without the SGIP incentive payment. The only case where the maximum ratepayer neutral incentive is larger than the net participant cost of adoption SIS units is when generation capacity is valued at \$250/kW-yr (representing a local capacity constrained area such as the LA Basin).

**Table 1-8. Maximum Ratepayer Neutral Incentives for Adoption of SIS Units Under Utility dispatch. (\$/kW-yr.)**

Case	Feeder	Utility Benefits	Customer Bill Savings	Maximum Incentive	PCT w/o SGIP
<b>Base Case</b>	JS	\$251	\$123	<b>\$128</b>	<b>-\$248</b>
	WG	193	123	<b>70</b>	<b>-248</b>
<b>High DER</b>	JS	244	123	<b>121</b>	<b>-248</b>
	WG	149	123	<b>26</b>	<b>-248</b>
<b>TOU+CPP</b>	JS	251	110	<b>141</b>	<b>-261</b>
<b>Larger SIS Units</b>	JS	265	96	<b>169</b>	<b>-239</b>
<b>Ancillary Services</b>	JS	250	119	<b>131</b>	<b>-225</b>
<b>2016 TOU</b>	JS	251	137	<b>114</b>	<b>-234</b>
<b>PG&amp;E TOU Rate</b>	JS	251	227	<b>24</b>	<b>-144</b>
<b>PG&amp;E Demand Charge Rate</b>	JS	251	183	<b>68</b>	<b>-184</b>
<b>\$250/kW-yr. Capacity Value</b>	JS	433	123	<b>310</b>	<b>-248</b>

#### 1.5.4 COST-EFFECTIVENESS SUMMARY

We investigated the value of customer adoption of SIS units from many perspectives and in many sensitivities in the case study above. Most scenarios studies had a net TRC cost, but distributed energy storage dispatched for utility and customer benefits could have net TRC benefits in a local capacity constrained area with high capacity value. On the Jackson-Sunrise feeders with high deferral value, adding energy storage with utility dispatch reduced the RIM cost compared with adopting PV alone, but without utility dispatch, the net RIM cost increased significantly. In most cases, the maximum ratepayer neutral incentive that a utility can provide to customers purchasing an SIS unit is less than the SGIP incentive.

Distribution upgrade deferral can account for more than half of the value of an SIS unit to the utility when distributed energy storage can defer upgrades. However, distribution feeder peak loads are not necessarily well aligned with the system loads around which TOU rates are designed. On the Jackson-Sunrise feeders, distribution deferral is not achieved with TOU rates alone, but only by allowing the utility some ability to dispatch the storage based on local conditions.

- ⊕ Storage is not cost-effective for customers under SMUD TOU-CPP rate with NEM, which only has TOU periods during the summer. Annualized costs of \$520/kW-yr. exceed the bill savings by \$85/kW-yr. Under the PG&E E-TOU Rate with NEM, which has TOU periods all year, the bill savings do exceed the costs by \$9/kW-yr. However, the net participant benefit with storage is lower than with PV alone (\$50/kW-yr.). This is an expected result, as PV generation falls predominately in on-peak TOU periods..
- ⊕ PV system costs of \$220/kW-yr. exceed Total Resource Cost (TRC) benefits by \$91/kW-yr. on Jackson-Sunrise and by \$68/kW-yr. Adding storage increases the total cost to \$500/kW-yr. On the Jackson-Sunrise feeders, customer dispatched storage provides a TRC benefit of \$226/kW-yr. resulting in a net TRC cost of \$294/kW-yr. On the Waterman-Grantline feeders, the TRC benefit is slightly higher at \$277/kW-yr. for a net TRC cost of \$243/kW-yr. Utility dispatch increases the TRC benefits by \$160/kW-yr. (71%) on Jackson-Sunrise and by \$60/kW-Yr. (22%) on Waterman-Grantline, to a total \$386/kW-yr. and \$337/kW-yr. respectively, still lower than the costs of \$520/kW-yr. .
- ⊕ Including the SGIP incentive, under customer dispatch, Ratepayer Impact Measure (RIM) tests are also negative at a net cost of \$209/kW-yr. and \$158/kW-yr. respectively to non-participating ratepayers on the Jackson-Sunrise and Waterman-Grantline feeders. With utility dispatch, the net RIM cost is decreased significantly, but still negative: \$27/kW-Yr. and \$84/kW-yr. With customer dispatch, the RIM cost is higher than with PV alone and with utility dispatch, the RIM cost is lower than with PV alone.
- ⊕ With utility dispatch, we find the maximum ratepayer neutral incentive is \$116/kW-yr. and \$65/kW-yr. for Jackson-Sunrise and Waterman-Grantline respectively (as compared to SGIP incentive of \$150/kW-yr. that does not require utility dispatch). With larger bill savings under the PG&E rate, we find the maximum ratepayer neutral incentive would be \$26/kW-yr. with utility dispatch providing a deferral value similar to the Jackson-Sunrise feeders.

### 1.5.5 PROGRAM DESIGN

The research outlined in this paper demonstrates that there is a value to the utility for residential behind-the-meter PV integrated with storage systems. The storage industry is in the early commercialization phase for the residential sector where upfront costs of the technology can be a barrier to adoption. To fully harness the value of a PV integrated storage system and to overcome the storage technology cost barrier, properly designed utility programs that stack the customer and utility value streams together are needed to transform the market. The utility first needs to consider a variety of factors before choosing the program components that best fit the specific utility's goals. We described the various program factors to review and recommend narrowing down priorities before designing a program. We then described the use case, benefits and drawbacks of two major components of a program: incentive options and ownership models.

Finally, we described three example program configurations. The first example shows how the real world use case of SMUD, analyzed earlier in this report, fits into the program design process. The second example uses the program design framework but in a hypothetical use case to show how the framework operates under a different set of circumstances. Finally, in our third example we described how a dynamic Full Value Tariff (FVT) can encourage customers to dispatch BTM storage to maximize grid benefits without direct utility dispatch.

## 1.6 Conclusions and Recommendations

- + Sunverge successfully integrated SIS units with SMUD's demand response management system to automate DR events. The communication and subsequently, the functionality has limitations due to the communications protocol (OpenADR 2.0a), but can be overcome with the more robust OpenADR 2.0b protocol or direct communications with Sunverge's Control Software.
- + Only modest local distribution operational benefits are demonstrated for this case study. The results affirm findings from prior studies that operational benefits from DERs are highly location specific.
- + Under the assumptions modeled, PV plus storage as applied in this pilot project is not cost-effective under the TRC at near-term projected prices. Distributed storage can still be cost-effective in local capacity constrained areas or on distribution feeders with high deferral value.
- + We do find, however, that adding storage to PV can provide incremental benefits that exceed the cost of the storage system. Stated alternatively, the total cost of PV and storage exceed the TRC

benefits, but the incremental TRC benefits of storage can exceed the cost of the storage system in some cases.

- + Combining customer and utility benefits is a promising business case for storage. The stack of benefits from the customer and utility perspective cannot simply be added together as some are mutually exclusive. Still, enabling utility dispatch (or providing dynamic rate signals) during certain high-value hours could combine the high value customer benefits (reliability and bill reduction) and utility benefits (local capacity and distribution deferral) in one application.
- + Storage that is dispatched on the customer's behalf to maximize bill savings does not provide benefits that exceed the loss of revenue to the utility under any scenario studied. The NEM cost-shift to non-participating ratepayers with storage is higher than with PV alone.
- + With utility dispatch or a dynamic Full Value Tariff, the benefits realized increase substantially relative to customer dispatch under a standard TOU or TOU-CPP rate. For the Jackson-Sunrise feeder in this case study, the total TRC benefits when storage is dispatched to meet both utility and customer objectives are up to 2.5 times higher when dispatched for customer benefit only under a TOU-CPP rate.
- + A CPP rate called based on system peak loads will result in load reductions that may not coincide with local distribution peak loads on many feeders.
- + The benefits of distributed storage are higher for feeders that peak later in the day after PV generation declines, and under higher penetrations of PV on the feeder, that push net load peaks to later in the day.
- + Allowing the utility to dispatch storage to charge from the grid in the morning on high load, low PV generation days would increase the reliable system and distribution peak load reductions more than when storage is limited to charge from PV alone.
- + A program including dispatch for utility as well as customer benefits or a dynamic Full Value Tariff is technically feasible and potentially attractive for customers. Furthermore, such a program provides significantly more value to the utility and its ratepayers than programs (such as California's Self Generation Incentive Program) that provide incentives for installing storage that is dispatched for the customer's benefit only.
- + A utility sponsored storage programs can be developed around three primary motivators: 1) utility drivers and concerns, 2) customer drivers and 3) storage industry barriers. The report describes program incentive and ownership options that can be designed around these primary motivators.

## 2 Introduction

### 2.1 Policy Context

Interest in distributed energy resources (DER) broadly and photovoltaic (PV) and energy storage in particular are being driven by a number of California's policy and market transformation initiatives seeking to increase deployment of renewable generation and reduce GHG emissions. Governor Brown signed SB 350 in October 2015, increasing California's renewable portfolio standard to 50% by 2030. Storage can support the addition of intermittent renewables and support grid reliability. California AB 327 requires California investor owned utilities (IOUs) to consider DERs as part of their distribution system planning process for deferment of traditional infrastructure projects and the California Public Utilities Commission (CPUC) has initiated Integrated Distributed Energy Resource (IDER) and utility distribution resource planning (DRP) proceedings.<sup>8</sup> California AB 2514 requires all three CA IOUs to procure a combined storage capacity of 1.325 GW by 2020, of which 200 MW must be customer sited.

In January 2016, the California Public Utilities Commission (CPUC) issued a decision continuing net-energy metering (NEM) or behind-the-meter (BTM) PV. Today there is 3.8 gigawatts (GW) of BTM PV. With the extension of NEM and declining cost of PV, the NEM Public Tool developed by Energy and Environmental Economics for the CPUC (Energy and Environmental Economics, 2015) projects 17 to 21 GW of BTM PV adoption by 2025.

Energy storage is one of several strategies that can support regional and local utility grids as penetration of intermittent renewable generation increases. Storage can also provide peak load reductions in locally constrained areas where siting of new generation and transmission assists is especially difficult. For example, Southern California Edison (SCE) acquired more than 250MW of energy storage to meet local capacity requirements in the Western LA Basin and Moorpark sub-areas.

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<sup>8</sup> R. 14-10-003 and R. 14-08-013

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## 2.2 Project Objectives

This project is designed to demonstrate and quantify the value that BTM PV integrated storage can provide for the utility and its ratepayers. The objectives of this project are to:

- + Translate demonstration of high penetration distributed PV integration into tangible policy and planning recommendations
- + Document performance with high resolution metering of PV production, customer loads, energy storage dispatch
- + Demonstrate dispatch of customer-owned energy storage for customer and grid benefits with utility's Demand Response Management System
- + Develop robust estimates for local distribution system operational benefits, supported by OpenDSS power flow modeling
- + Overcoming near-term cost barriers by demonstrating simultaneous customer and utility benefits for behind-the-meter energy storage with Integrated Distributed Energy Resource modeling
- + Develop tariff and incentives, program designs and customer outreach strategies for behind-the-meter energy storage

# 3 Project Approach

## 3.1 2500 R Midtown Project<sup>9</sup>

In 2009, SMUD received a Smart Grid Investment Grant from the US DOE to help fund SmartSacramento, one of the Nation's most comprehensive smart grid rollouts. The project intended to establish the smart grid infrastructure and begin building out the extended smart grid capabilities in order to better serve SMUD customers. While the groundwork was laid in the early years of the project, customer programs weren't complete and evaluated until September 2014. SMUD partnered with 2500 R Group, LLC, a joint venture between Sunverge and Pacific Housing Incorporated, to implement the 2500 R Street smart home demonstration.

**Figure 3-1. Arial Rendition of 2500 R Midtown Homes.**



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<sup>9</sup> Much of the following section is taken directly from the "2500 R Street Integrated Energy Management Use Case Report", December 2014, Prepared by ADM Associates. DOE Award Number OE000214

**Figure 3-2. 2500 R Midtown Units.**



2500 R Midtown is a 34-unit single family development in midtown Sacramento located at 2500 R Street. The development consists of 28 two-story houses and six three-story houses, ranging in size from 1,251 sqft. to 1,828 sqft. Each of the development's 34 homes contains its own Sunverge Solar Integration System (SIS)—an innovation that makes solar energy more grid friendly than ever before. It not only generates solar energy through photovoltaic (PV) cells, but also stores this energy in lithium-ion batteries so that it may be held in reserve and consumed when energy demand is the most critical. The SIS is one component of the Integrated Energy Management Solution (IEMS), a comprehensive package that also consists of a programmable communicating thermostat (PCT) and remotely switchable outlets called “modlets” supplied by ThinkEco. The system also gives residential homeowners secure online access to their personal energy profile through a SIS web portal, which allows them to track and manage their electricity use and generation.

### **3.1.1 PV AND SUNVERGE INTEGRATED STORAGE SYSTEMS AT 2500 R ST**

The Sunverge integrated energy management solution employed for this project consisted of three components which were installed in all 34 houses. They are:

1. Sunverge's SIS consisting of solar PV panels, lithium-ion battery storage, inverter, and integrated controls. The PV panels are rated at 2.25 kW output, inverter maximum output is rated to 4.5 kW, and the battery storage at 11.7 kWh<sup>10</sup>.
2. Programmable Communicating Thermostat (PCT): Carrier ComfortChoice® Touch with Zigbee communication protocol to a ThinkEco Ethernet gateway.
3. Modlet: a remotely controllable 120V wall outlet dual receptacle with Zigbee communication protocol to a ThinkEco Ethernet gateway.

**Figure 3-3. 2500 R Midtown Development.**



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<sup>10</sup> SIS units come in different configuration options with 4.5kW and 6.0 kW inverters and batteries ranging from 7.7kWh to 19.4kWh.

**Figure 3-4. Sunverge SIS Unit at 2500 R St. Home (SIS on right, AC unit on left).**



### 3.2 2014 Demonstration Project at 2500 R Midtown

Implemented in 2014, this demonstration project was designed to provide a benchmark in determining whether or not combined energy storage, distributed generation, and demand response could be controlled and aggregated in extremely energy efficient homes to provide grid management resources. The project evaluated whether these distributed energy resources could effectively be simultaneously used to manage electricity use and minimize costs. The value propositions associated with distributed assets such as these had not been proven within the utility industry and the project sought to answer some of the many unanswered logistical and operational questions. The 2500 R Street project allowed SMUD to implement, evaluate, and advance these technologies as part of its broader SmartSacramento initiative.

The objective of the 2014 Demonstration was to verify that the SIS and IEMS could be controlled to provide energy flow to the customer and the grid in pre-defined modes of operation that are beneficial to the utility and the customer. The various modes are classified as use cases and include: Customer Backup Power, Customer Bill Reduction and Peak Load Reduction. Sunverge also tested the capability of the SIS units to provide PV Firming.

Of the 34 homes in the new development, 10 customers signed up to be on a special rate that allows them to take advantage of lower rates outside of on-peak hours. These 10 customers participated in SMUD-announced conservation days by taking advantage of the automated advanced controls available through the SIS and IEMS. This included optimizing the use of solar PV generation and reducing demand. In the residential sector, load shifting on conservation days is an approach to demand reduction. Load shifting also occurred on non-conservation weekdays in the summer, but to a lesser extent. Load reduction combined with time-shifting of solar PV generation through use of the battery maximized each homes' response on conservation days. A variety of metering was installed to verify the operation of the IEMS and to quantify the demand savings and other use case benefits of the system. The non-participating customers were on SMUD's default residential rate, a seasonal, two-tiered flat rate with higher rates in the summer season.

SMUD customers on the default residential non-electric heating rate paid a flat rate of \$0.1033/kWh for the base amount up to 765 kWh/month during the summer months. Over that base amount, they paid \$0.1836/kWh. Customers that live in this development and sign up for a special time of use rate paid only \$0.064/kWh for the base amount and \$0.161/kWh above the base amount during the summer months. However, on non-holiday weekdays during the 4:00 pm-7:00 pm on peak hours the rate was \$0.28/kWh and jumped to \$0.75/kWh on conservation days called by SMUD.

**Table 3-1. Demonstration Participant and Non-Participant Rates.**

Participants		Non-participants		Participants and Non-participants		
Rate	Residential Smart Pricing Pilot Optimum Off-Peak Plan (1-R-SPO)	Standard Residential Nonelectric Heating (RSGH)	1-R-SPO and RSGH			
Season	Summer	Summer	Fall, Winter, Spring			
Year	2014	2015	2014	2015	2014	2015
<b>Monthly fixed charge (\$)</b>	14	16	14	16	14	16
<b>On-peak conservation day (¢/kWh)</b>	75	75	-	-	-	-
<b>On-peak (¢/kWh)</b>	28	28	-	-	-	-
<b>Off-peak base usage (¢/kWh)</b>	6.40	6.50	10.33	10.76	9.55	9.98
<b>Monthly base usage threshold (kWh)</b>	700	730	765	835	690	770
<b>Off-peak base-plus usage (¢/kWh)</b>	16.10	16.40	18.36	18.70	17.71	18.05

Load shifting and time-shifting of solar PV generation on conservation days at the participating homes was achieved through the following series of activities:

- + Using the SIS to store PV power during mid-day and sending this power to the grid during the high value on-peak period
- + Lowering the cooling set point prior to the on-peak period to pre-cool the house
- + Raising the cooling set point during the on-peak period to reduce air conditioning use
- + Using the modlets to turn off power to selected plug loads.

### 3.2.1 FINDINGS

ADM Associates produced the “2500 R Street Integrated Energy Management Use Case Report” in December 2014 summarizing the findings from the 2014 demonstration (ADM Associates, 2014). ADM installed independent metering on a sample of 8 homes in order to verify data being collected by the SIS, PCT, and modlets.

In the 2014 demonstration, the SIS response on non-conservation weekdays provided 1.35 kW of savings on average from the IEMS. The average incremental IEMS demand savings peaked at 2.80 kW during the first hour and averaged 1.31 kW for the entire on-peak period on conservation days compared to non-conservation weekdays for the participating houses. The average total IEMS load shifting on conservation days compared to no IEMS peaked at 4.38 kW and averaged 2.66 kW for the entire on-peak period. The peak and average demand savings during the on-peak period for different day types per control strategy are presented in Table 3-2. These assessments were made using standard demand response M&V evaluation techniques which may not fully capture the value provided by combined load reduction and distributed energy generation systems.

**Table 3-2. Average Demand Savings On-Peak Period by Control per House (kW).**

	Non-Conservation Weekday Demand Savings	Incremental Conservation Day Demand Savings	Total Conservation Day Demand Savings <sup>11</sup>
IEMS, Maximum	1.68	2.80	4.38
IEMS, Average	1.35	1.31	2.66
SIS & PV, Maximum	1.49	2.27	3.87
SIS & PV, Average	1.26	1.07	2.47
PCT, Maximum	na	1.16	1.16
PCT, Average	0.09	0.35	0.19
Modlet, Maximum	0.00	0.003	0.004
Modlet, Average	0.00	0.003	0.004

Fleet operation was confirmed, as all 10 participating customers were operated as a fleet. Analysis showed that they all contributed to the average load shifting savings on conservation and non-conservation days (ADM Associates, 2014).

A critical load panel in the house is wired so the SIS can maintain power to some of the homeowner's loads in the event of a grid power failure. Confirmation of the SIS units' capabilities as an uninterrupted power source was achieved through a simulated outage at one home and an actual grid disconnection at another home. Sunverge's SIS units have provided over 8,800 hours of backup power to residential customers over the past several years.

The SIS is functioning according to Sunverge's algorithm to provide PV firming. The current control settings provide firming on the time frame of one minute. Users are able to set a maximum deviation in power

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<sup>11</sup> The sum of maximum demand savings from non-conservation and incremental conservation days may not equal the total conservation day value because they occur on at different times during the on-peak period. The averages on the total conservation day may not equal the sum of the other two day types since incremental conservation day demands are referenced to the highest 3 of 10 non-conservation weekdays whereas the non-conservation weekday demands are averaged across all days of that type.

output from the system that should be allowed to occur during each 1-minute period. The battery is used to either discharge energy to support gaps in solar PV generation or to charge to smooth out spikes.

Individual unit and fleet regulation testing was completed as well and showed very promising results. The response time of the SIS units during testing was less than four seconds and the responses were within 100 W of the requests.

Many of the SIS use cases have competing resources or goals. For the purposes of this evaluation, testing for each use case was conducted independently. The SIS does have the capability to operate multiple use cases simultaneously through layering of programs based on priority and the ability to reserve portions of the battery for different use cases. When establishing the operation of the SIS, a strategy must be developed to identify which modes are the most important or financially rewarding to the invested party.

### **3.3 2015 Demonstration at 2500 R Midtown**

The CSI RD&D Round 4 grant funded a second demonstration in 2015 using Sunverge SIS units to demonstrate PV integrated energy storage use cases. The proposal funded by CSI included the deployment of 10 new SIS units to existing SMUD customers in Sacramento. The project team made a concerted effort in late 2014 and early 2015 to design and implement a program to deploy the 10 SIS units but due to a number of challenges, was not successful. Therefore, the demonstration was redesigned to use the 34 existing units at 2500 R Midtown. The 2015 demonstration includes two distinct periods. In June through September 2015 SMUD implemented its TOU-CPP rate, similar to the 2014 program described above. For this CSI funded project, we also conducted additional demand response test events in October and November, after the SMUD TOU-CPP rate tariff was no longer in effect.

#### **3.3.1 2015 Demonstration Program Redesign**

The project initially intended for SMUD, Sungevity and Sunverge to deploy 10 SIS to existing SMUD customers. The 10 units were purchased by SMUD in 2014 and are stored in a SMUD warehouse. Sungevity was to recruit 10 customers and install a new PV system integrated with a Sunverge SIS unit.

We encountered several challenges over the course of the project that prevented the deployment of the 10 SIS units to retail customers.

There were administrative challenges around transferring ownership of the SIS units between SMUD and Sungevity. There were legal complications around warranty transfers, and SMUD's ability to sell or transfer ownership of capital equipment; the accounting, billing and contractual approval processes for doing so would have to be specially created just for these 10 SIS units. SMUD had purchased the Sunverge units for this project, but for accounting and liability reasons, it was not reasonable for SMUD to resell them directly to customers either.

Furthermore, Sungevity and Sunverge entered into exclusive business partnerships that limited their ability to pair Sungevity PV systems with Sunverge SIS units for this project. Despite mutual interest in the project, the exclusive business partnerships made it difficult for Sunverge and Sungevity to share sensitive information about their respective technologies and for Sungevity to take on customer support for the full lifetime of the Sunverge SIS units beyond the demonstration project period. In addition, Sungevity's financing partners did not allow storage to be co-sited (even with a separate inverter) with the PV system. Sungevity explored alternative financing options and found that Property Assessed Clean Energy (PACE) financing is available for PV systems integrated with energy storage. SMUD also proposed that the utility could provide financing options to customers, though the PACE interest rates were more attractive. The project team therefore decided to focus on demonstration at the SIS units already installed at the 2500 R St. site. This delay shortened the available time for demonstration in 2015.

## 3.4 PV Integrated Energy Storage Use Cases Demonstrated

### 3.4.1 USE CASES DEMONSTRATED

#### 3.4.1.1 *Customer Backup Power*

A portion of the SIS energy storage capacity is always reserved for customer backup power, but the exact capacity can depend on how much is reserved for other use cases. In the 2500 R St. demonstration project, Sunverge reserved at least 30% of storage capacity (3.5kWh) during non-conservation days, and at least 15% of storage capacity (1.8kWh) during conservation days for backup power after the peak period. The backup power reservation ensures that customers' critical loads are supplied during a grid outage or disturbance. The duration of backup power varies based on available PV, stored energy and power drawn from critical loads. For example, with 3.5kWh available battery, a 1.5kW load can be supplied for 2.33 hours with battery alone, but longer if solar is available to supply the loads and recharge the battery.

#### 3.4.1.2 ***Customer Bill Reduction***

The portion of the battery not reserved for customer backup power is used to maximize bill savings for the retail customer. For customers on a TOU CPP rate, the SIS unit is charged from PV before the on-peak TOU period. During the on-peak TOU period both PV generation and energy stored in the SIS unit are used to offset customer loads and export net power to the grid. For regular (non CPP) TOU days, Sunverge targeted dispatch was at least 50% of the battery's capacity, plus any net PV generation. For CPP days, Sunverge targeted dispatch was at least 75% of the battery's capacity plus net PV. On CPP days, the strategy was to maximize the amount of energy dispatched during the higher rate peak period, so customers would see higher bill reductions and SMUD would be supplied with capacity for demand response events.

#### 3.4.1.3 ***System Peak Load Reduction (SMUD TOU-CPP Rate)***

For customers enrolled in the TOU-CPP rate, the SIS unit was programmed to reduce the customer's impact on system peak load. The operation of the SIS unit is designed to reduce loads on the utility grid during on-peak TOU periods and provide additional load reductions/grid exports during CPP events. This operation is designed to both benefit the system peak as well as assist customers in bill management by reducing their overall electric bill.

#### 3.4.1.4 ***Distribution Peak Load Reduction***

This use case is functionally the same as system peak load reduction, but dispatches storage to shift local distribution system peak loads. SMUD's current implementation of Synergi does not yet facilitate DRMS dispatch based on local conditions. We therefore use the results of the system peak load reduction events as proxies for how the SIS units would respond to utility dispatch for local distribution peak load reductions. We use RMI and E3 models to simulate storage dispatch in response to feeder loads and quantify the operational impacts and economic benefits.

#### 3.4.1.5 ***Predictable Dispatch***

SMUD wanted to demonstrate that the SIS units could provide a predictable level of dispatch. In 2014, SMUD and Sunverge observed sudden changes in net-load sometimes occurred as the battery reached its

minimum state of charge (SOC) limit and immediately changed its dispatch from full to zero discharge. The goal for predictable dispatch is not to provide a strictly flat net-load, but to graduate the storage discharge over the full event period to avoid sudden changes in the net load observed by the utility. Additionally, Sunverge ‘flattened’ the net-load (net energy exported from SIS unit to utility grid) in order to provide SMUD with a more predictable net load over the course of each event. Establishing a steady, flat net load forecasts increases the attractiveness of using energy storage as a resource and more closely mimics the predictable attributes of generation when considering individual homes as part of the fleet. The primary purpose of flattening the load profile is not to reduce the customer bill savings.

To provide predictability for SMUD, Sunverge sent out aggregated forecast capacity reports prior to several events, which showed a target power dispatch level for the fleet with a tolerance band. Although storage behind the meter can be used to serve utility grid needs, it is necessary to provide the utility with a confidence level and statistical range of expected PV and SIS performance for a given event. The forecasts were created based on a model that factored in estimated PV, total load demand, and available energy capacity in the fleet of batteries, adjusted for daily conditions. This strategy laid the foundation to create an automated program that factors changing real time conditions and solar forecasting to more accurately determine total available battery capacity.

### 3.4.2 USE CASES CONSIDERED BUT NOT EVALUATED

#### 3.4.2.1 *Limited Ramping*

The team considered adding a ramp up and ramp down period for dispatching energy at the beginning and end of DR events, intended to make it easier for grid operators to plan for net load and maintain balance. This was initially tested, but deemed to not be of high value to SMUD, and dropped as an operational goal for later tests.

#### 3.4.2.2 *PV Smoothing*

SMUD considered PV smoothing a lower priority need for residential solar at today’s market penetration compared to larger scale solar. Residential solar on a distribution feeder when at a low penetration (a fraction of the PV hosting capacity limit) has a relatively low variability that is diversified with the load consumption. However, for larger scale solar or feeders with a high penetration of PV, the generation

variability may be high enough to pose challenges with power quality (voltage) and at a very large scale with system balancing.

#### 3.4.2.3 *Backflow Prevention*

This use case was deemed a low priority because current penetrations of PV on the SMUD system do not pose significant backflow problems. Backflow occurs when PV generation on the local distribution system exceeds load and power flows ‘backward’ or upstream through transformers on to other feeders or up to the substation. The project team developed an approach to use SIS units to prevent backflow of PV generation from the feeder to the substation. This use case is technically feasible for the SIS units, an OpenADR command could be sent by SMUD during periods when low customer loads coincide with high PV generation and present the potential for backflow. The demonstration of backflow prevention will be of more interest when SMUD has developed more advanced DRMS capability to automatically send location specific signals based on individual feeder conditions.

#### 3.4.2.4 *Frequency Regulation*

Frequency regulation is an important need for utilities as the contribution of variable renewable generation increases. However, frequency regulation requires a high bandwidth connection and more sophisticated interface than the peak capacity use cases demonstrated here with OpenADR 2.0a. The project team explored demonstrating frequency regulation, with assistance of Customized Energy Solutions (CES). CES described how its SecureNet service could provide actual or simulated frequency regulation signals to the Sunverge SIS Cloud Server or to each SIS unit individually. Though technically feasible, we determined that such a demonstration was not possible with the available time and budget for this project.

## 3.5 Demand Response Management System (DRMS) Integration

Utilities are exploring the benefits of distributed energy storage (DES) as an additional resource for their demand response portfolio. In particular, residential DES is more valuable to utilities, including SMUD, when these technologies are seamlessly integrated into the utility’s grid operations. Integration enables increased flexibility, quick response time, and convenience from having energy readily available at the distribution level. The SIS provides grid operators with remote control to aggregate a fleet of behind-the-

meter energy storage systems into virtual power plants that can be dispatched for grid services, such as reducing network peak loads during constrained periods.

For this project, Sunverge created a new module in its SIS control software, the Sunverge Software Platform that allows it to integrate with SMUD's demand response management system (DRMS) using Open Automated Demand Response (OpenADR) communication protocol. The Sunverge system polls the SMUD DRMS every minute looking for a demand response event notification. When the Sunverge system registers a DR event the SIS units to dispatch energy according to the event specifications. This Sunverge module and integration was tested using the SIS units at 2500 R Midtown.

SMUD and Sunverge were mutually excited to partner on a project that tested the automation capabilities of dispatching energy from a fleet of SIS units for demand response. The primary goal was to demonstrate the functionality of the Sunverge Software Platform to accept and translate DRMS signals to provide demand response capacity. The demonstration also provided an opportunity to test ancillary goals, which included capacity forecasting for SMUD, algorithm optimization for Sunverge, and shaping the exported load to the grid.

### 3.5.1 OPENADR IMPLEMENTATION

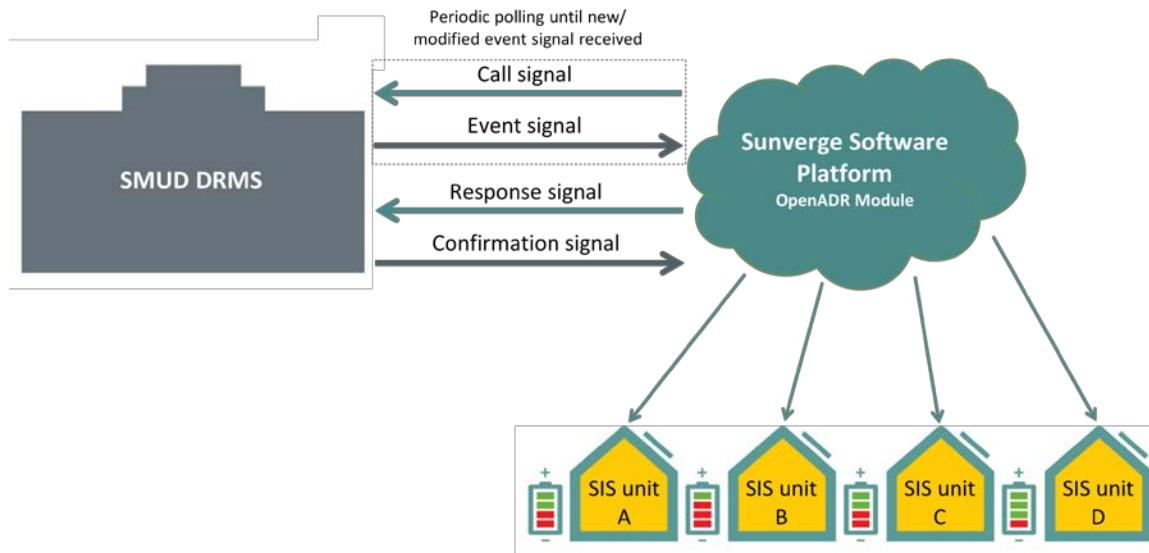
SMUD uses SEEload by Lockheed Martin as their DRMS and the OpenADR 2.0a communications protocol to integrate with third party control systems. OpenADR was developed by a consortium of industry stakeholders to provide a standardized model to communicate data for automated DR programs and other ancillary grid services over various DRMS platforms and data architectures. Sunverge developed the OpenADR module based on the technical profile specifications of the protocol and designed to SMUD's specific implementation of OpenADR 2.0a. SMUD provided examples from other integrations to assist Sunverge in developing a module that could receive SMUD-specific event signals.

SMUD has been using OpenADR to dispatch DR programs since 2013. Utilizing OpenADR allowed SMUD to work with a protocol that they were already familiar with and implementing, minimizing integration work necessary from SMUD. Also SMUD determined that dispatching the SIS units via OpenADR, instead of using the existing energy storage module within SEEload, was preferable. The SEEload energy storage module was jointly developed by Lockheed Martin and Sunverge in 2012 to dispatch and manage SIS units for demand response. The energy storage module in SMUD's version of SEEload had not previously been

activated, however, and the IT resources required to verify the functionality were not available to support the project. Additionally, SMUD was planning to upgrade to a DRMS that may not be backwards compatible. Furthermore, SMUD's current application of SEEload does not include the distribution-level performance monitoring and controls needed to automate use cases at the distribution level. SMUD would not be able to use the DRMS to identify constrained resources on the grid (such as feeders) and dispatch DR signals to relieve those resources.

The diagram below illustrates how SMUD's DRMS communicates with Sunverge's Software Control Platform through various OpenADR signals. This back and forth communication allows SMUD to call DR events, and Sunverge to operate a fleet of SIS units using the OpenADR 2.0a standard protocol.

**Figure 3-5. OpenADR 2.0a Protocol Communication Diagram.**



The OpenADR module in the Sunverge Software Platform accepts standard XML Event Signals that provide the details on the requested DESS operation and the event timeline. The event signal fields include:

- + Signal payload - This is a numerical code that describes the level of the event (0=normal; 1=moderate; 2=high; 3=special). In this demonstration, the number corresponded to a use case that was pre-determined by SMUD and Sunverge. (See "SIS programming and response" for more information on these use cases.)
- + Start time – The time (in UTC) at which the DR event will occur.
- + Duration – The length of time, in days, hours, minutes, and seconds that the DR event will occur.

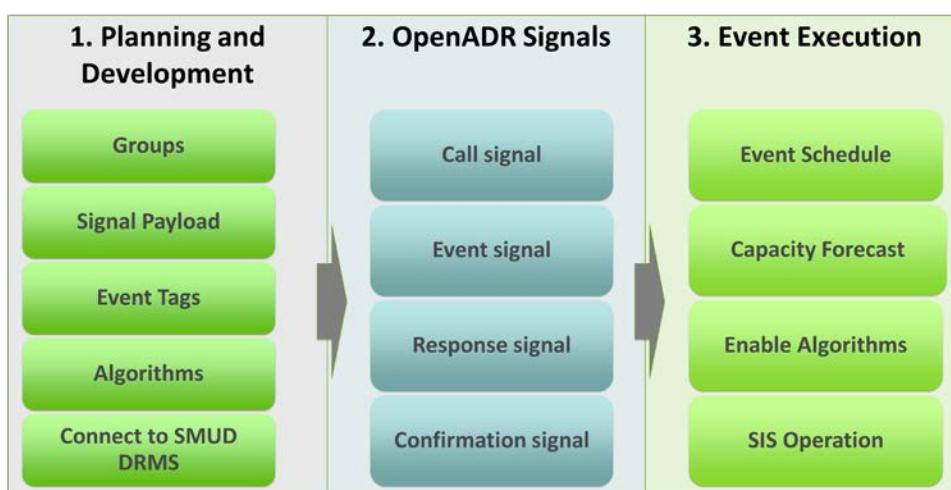
- + Event status (included, but not used in this operation of the program) – An indication of the current event state. “FAR” means an event that is greater than 30 minutes away; “NEAR” means an event that is less than 30 minutes away; and “ACTIVE” means the event is currently happening.

OpenADR allows for several more event description fields, including priority, and whether the event is a test. However, for the application of this demonstration, SMUD chose to limit it to the descriptors above.

SMUD provided an end point and credentials for the Sunverge OpenADR module to connect with its DRMS. The connection was established, and the Sunverge Software Platform uses a pull method with a call signal to poll the DRMS every minute to check for new DR event signals. SMUD can create DR event signals in advance, from two days ahead to day-ahead to 10 minutes before. These parameters are configurable in the SMUD DRMS and depend on the program resource requirements and the customer DR equipment capability for the program. The event signal is received by the OpenADR module and creates a unique Event ID that identifies event details. The Sunverge OpenADR module sends a response signal that it is participating in an event back to SMUD’s DRMS, after which point, SMUD’S DRMS sends a confirmation signal back to Sunverge to complete the calls.

The Sunverge Software Platform then responds automatically by setting, unsetting, and scheduling the correct control programming on the participating SIS units. These programs activate or deactivate modes of operation in SIS units. The operation of the SIS units was determined by following the basic logic path illustrated in the diagram below.

**Figure 3-6. DRMS Integration and DR Event Execution Process.**



Each new or modified signal received overrides any previous signal for the current Event ID. For example, if the utility wants to cancel a previous signal to instate a new signal, it will post the new signal with updated information. The OpenADR module can accept signals with multiple events, and will schedule on a timeline, according to the start time and duration of each of those events. The response time for the SIS software after receiving an event signal is a few seconds, which can be useful in an emergency DR situation.

### 3.5.2 SIS Programming and Response

Sunverge, SMUD, and E3 worked closely together to determine which use cases would be tested with the OpenADR integration. The initial proposal was to test three distinct use cases. However, the project team decided that given the limited timeline, it was best to focus on testing one use case, Distribution Peak Load Reduction, and multiple technical functionalities. The technical tests included the ability to receive and respond to a signal, schedule multiple events, and the development of the forecast capacity.

The Distribution Peak Load Reduction program was given a Payload value of “0”, which activates a similar algorithm used for CPP days in the summer. The module allows for more Payload numbers to be assigned for new programs in the future.

Operationally, receiving a CPP event signal with OpenADR is identical to receiving day-ahead emails from SMUD operators, except that the process is entirely automated. The control strategy remained the same: charge the battery to full capacity the day or morning before an event to maximize the energy dispatched from the batteries during an event. By default, batteries were fully charged in case of a short-term notification, but the best way to ensure full battery capacity was to send a day-ahead signal. Because the OpenADR integration occurred after the TOU CPP rate was in effect, customer bills were not significantly impacted. This gave SMUD and Sunverge the freedom to test different event durations, advanced signals, and dispatch strategies.

During each event, an optimized algorithm is set for every SIS unit that factors in individual home load demand, PV generation, and available battery capacity. Changing conditions impacted the accuracy of the estimated capacity forecasts provided to SMUD. The following test results do not reflect the improvements Sunverge has since made to its software algorithms, which more intuitively responds to conditional changes.

### 3.5.3 DRMS OPENADR INTEGRATION PERFORMANCE

SMUD, Sunverge, and E3 developed a number of technical functionality tests to coincide with this demonstration, both to evaluate the program in different DR event scenarios and to improve the algorithm and capacity forecasting for a future participation in SMUD's DR portfolio. The first demonstration test validated the Sunverge Software Platform's ability to communicate with SMUD's DRMS to control energy dispatch from SIS units for a DR event. Subsequent events tested the functional capabilities to: receive multiple signals in one day, a new signal in concert with an occurring event, multiple events in the same day; and receive signals day before, day of, and within 10 minutes of a DR event. The test results were all positive, validating that the Sunverge Software Platform OpenADR integration could successfully receive and respond to event signals at any level of advanced notice.

The algorithms were tested for varying event durations, from 1-hour to 6-hours, and short, back-to-back events to maximize the dispatch of usable battery capacity, while minimizing the need to import power from the grid over the course of the DR event. This strategy provides peak load reduction to the utility, and bill savings to NEM customers on a TOU rate tariff. Additionally, SMUD wanted the shape of the load to be flattened, in order to provide more predictable behavior on the grid. The algorithms for each SIS unit targeted an optimal power output that in aggregate would not fluctuate considerably. This can be difficult to do in concert and to forecast capacity for the grid, since each SIS unit's target power output depends on a forecast of the home's load, PV production, and battery capacity.

Over the eight test events (#9–#16), two were able to maintain a flattened shape through the majority of the event (80%+). This was defined by the amount of time that the aggregate exported load was within a predefined success band. Additional forecasting improvements need to be made to the algorithm to consistently ensure a flattened load shape. See section 4.1.2 for a summary of the test results.

Some of the initial test events also included ramping controls during the first and last 15 minutes to gradually smooth the rate of export. SMUD ultimately decided that ramping controls were not crucial to the utility to provide capacity predictability, and no longer necessary to test in later events.

### 3.5.4 LESSONS LEARNED FROM USING OPENADR PROTOCOL

Though the OpenADR integration to SMUD's DRMS was delayed a few months from the target deadline, it gave SMUD and Sunverge the chance to field test various DR simulations that could otherwise not be

done. For example, one of the events had a 6-hour duration and was not limited to the 3-hour, 4-7pm timeframe. Sunverge tested the new OpenADR module in the SIS software, and validated its ability to integrate with a utility's DRMS. SMUD demonstrated the possibility of incorporating SIS units, as DESS resources into its DR portfolio. OpenADR was a crucial element in standardizing the communication application between the DRMS and the Sunverge Software Platform, but did come with a set of challenges.

#### 3.5.4.1 *OpenADR Advantages*

OpenADR was created as a standard way for utilities and grid operators to easily automate communication with third party DR control software. It was a simple protocol for Sunverge to configure and develop as an integration module in its software, and it successfully connects to SEEload. The event signals, in XML, are a common format for utilities that also provide unambiguous interpretation when received. The development was relatively straightforward, given that SMUD provided example XML files containing only three data fields (i.e., Payload, Start Time, and Duration). Now that the module exists on the SIS software, portions of the code could be re-used in another utility application, as long as the utility's OpenADR model is implemented in a similar fashion to SMUD. While Sunverge did utilize an OpenADR event signal, the SIS unit did not go through the entire OpenADR 2.0a certification process. This was deemed unnecessary in this pilot effort. If Sunverge did complete the certification, then the SIS units would be able to communicate with all other 2.0a end points and not just the SEEload end point.

The signals can be expanded easily to incorporate additional data fields, which give DR managers and DER operators flexibility to define additional event parameters. For instance, priority levels can be set, where signals marked "high" will supersede conflicting "medium" or "low" signals.

The technical integration, using OpenADR was an important first step in proving the concept. SMUD can use this demonstration to begin planning a formalized DR program that incorporates DESS devices.

#### 3.5.4.2 *OpenADR Disadvantages*

The Sunverge Software Platform provides dynamic functionality to operate a fleet of SIS units for various use case operations, including dispatching DR capacity and other network services. The software provides a feedback loop that evaluates several metrics in real time and can respond to commands within seconds to adjust algorithms in each SIS unit for optimal fleet performance. From a program implementation

perspective, using OpenADR 2.0a created limitations in the application of Sunverge's software and its algorithms. The simplicity in the data communication protocol means that the complexities in implementation are passed on to the operator (Sunverge) and utility (SMUD) to plan in advance. The protocol is set up so that the utility is not commanding a customer to operate in a specific way, but instead notifying the customers equipment that a DR event is taking place. This set-up allows the protocol to be used by a variety of end users.

In OpenADR 2.0a, these complexities, such as evaluating available load capacity, are not taken into account when sending event signals to command SIS operations. That means there's little flexibility to adjust SIS operations if conditions change, for instance, when there is no available DR capacity. The Sunverge Control Software does allow this high level of control, while also providing a visual data interface for operators.

It is the utility's obligation to unambiguously define how it wants its DER assets to respond before the start of a DR program. OpenADR 2.0a signals do not transmit more than basic details. In this application, the signal payload field can be set to the numbers 0 through 3, which respectively correspond to the following: 0=normal, 1=moderate, 2=high, 3=special. As the only field that can define the how the SIS should operate, the 4 levels limited the granularity of controls that the Sunverge Software Platform is capable of. For instance, with the 2.0a protocol SMUD cannot request to deploy a certain capacity (e.g., 1 MW) from the fleet of SIS units; it must rely on one of four signal payloads to define the event use case, and Sunverge must send a separate capacity forecast report in order for SMUD to predictably reduce the demand at a feeder. The 2.0b protocol does allow a utility to request a deployment of a certain capacity, percentage reduction, and other more sophisticated requests.

OpenADR 2.0a protocol includes only feedback that is received from both SMUD and Sunverge side, while the 2.0b protocol allows for greater feedback and telemetry. SMUD's DRMS receives feedback that the event signal was received and algorithms are activated. Sunverge's module receives feedback that it is connected to the DRMS and querying event signals. Due to the lack of performance feedback in the 2.0a protocol, SMUD's DRMS and Sunverge's Software Platform can only respond to changing event conditions using an overriding event signal. The Sunverge Software Platform provides a robust set of features that can better be utilized with the OpenADR 2.0b protocol.

As utilities' use cases for DESS evolve, the implementation strategies will become more complex and require a lot of software development work and operation planning to successfully execute commands. For example, SMUD plans to participate in the energy capacity market in California in the future. To accommodate these needs, the OpenADR 2.0b protocol will be a better fit than the 2.0a protocol that was tested in this demonstration. The OpenADR 2.0b protocol can send signals such as price of electricity, demand charge, customer bid levels, battery charge state and more. The OpenADR 2.0b protocol lays out a standard set of fields and features but not all utilities use each field or feature so there is still some integration needed between a certified 2.0B end point and 2.0B client such as the SIS units.

#### 3.5.4.3 *Recommendations for DRMS integration*

It was relatively simple to establish the communication between SMUD's DRMS and Sunverge's software. Most of Sunverge's development resources were spent creating a user interface for the operator to log-in, and to program the response algorithms once an event signal is detected. Technologically, OpenADR enables a quick setup, and focuses on simple event notifications to allow the end user to respond in the best way for that end user. Straightforward operations, like this particular SMUD and Sunverge demonstration can benefit from using OpenADR due to the rapid development time.

OpenADR 2.0a was developed to send limited fields over an event signal, which can restrict the complexity of operations that can be executed. DESS operators may want to consider integrating to Sunverge's Partner API to take advantage of the full capabilities of the Sunverge Software Platform. Alternatively, a utility customer could consider developing a DRMS integration using OpenADR 2.0b as a communication protocol, as this level provides a feedback mechanism to adjust the response from deployed SIS units. This strategy would still present restrictions on the available capabilities of the Sunverge Software Platform, and requires additional development resources to integrate, compared to OpenADR 2.0a.

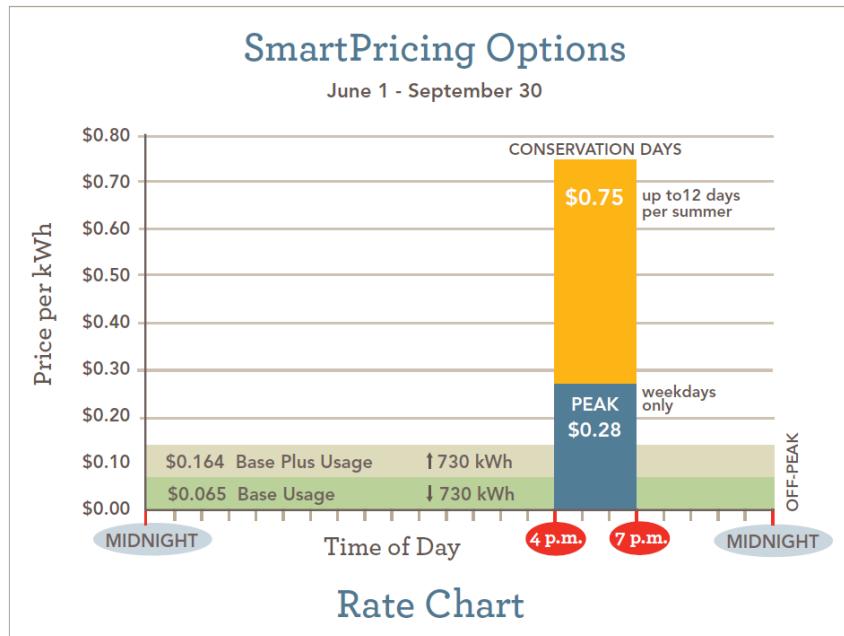
# 4 Project Outcomes

## 4.1 2015 Demonstration

### 4.1.1 SUMMER TOU-CPP USE CASE TEST (JULY-SEPTEMBER 2015)

The project implemented a use case test to assess the capability of SIS units to reduce system peak load and optimize performance in accordance with a TOU-CPP rate structure. SMUD's marketing group reached out to the 2500 R Street residents and recruited 17 customers to participate in a time-of-use with critical peak pricing (TOU-CPP) rate structure for research purposes. Figure 4-1 shows the shape of the TOU-CPP rate in 2015. Table 3-1 shows the detailed Participant and Non-participant rates for both 2014 and 2015.

**Figure 4-1: TOU-CPP rate structure.**



Sunverge leveraged the approach developed for the 2014 demonstration to provide peak load reduction and customer bill savings for the summer test period. For the TOU daily peak period, the primary goal in 2014 was to offset loads at the home using the SIS, while reserving a portion of the battery for back-up power. Based on average home total and critical load usage, Sunverge revised this methodology to

increase customer savings. In addition to supporting the total home's load during the peak period, Sunverge targeted a dispatch of at least 50% of the battery capacity, equivalent to about 5.9kWh, during summer weekdays. This approach intended to leave adequate battery capacity to support critical loads in the event of a SMUD power outage or disturbance.

Regarding CPP, similar to the TOU rate, Sunverge leveraged the 2014 demonstration approach for providing customer bill savings on CPP days. The primary goal was to offset loads at the home using the SIS and maximize exports to SMUD's utility grid. In both years, Sunverge targeted a larger dispatch on CPP days of at least 65% of the battery capacity, or about 7.54kWh.

The 2014 programming allowed for a significant amount of export at the beginning of the peak period (4-7pm), with the amount of exports tapering off significantly from 5-7pm. This approach allowed Sunverge to modify system output in response to changing energy usage in the home throughout the time period of the event while ensuring maximum energy offset. The most significant change in approach for the 2015 implementation was the shape of load export, which was changed toward the end of the summer and into the fall demonstration tests. The load was flattened for export from 4-7 pm to create predictable, reliable export profiles. This required Sunverge to adjust the algorithm to a fairly consistent export rate that factored changing home loads and PV generation.

### Use Case Test Goals

- + Demonstrate ability of SIS to optimize peak load management and TOU bill savings. During weekday peak hours, 4-7pm, on non-conservation days, offset demand by using SIS unit.
- + Demonstrate ability of SIS to shift renewables' time of use by capturing the PV generated off-peak to charge the battery and using stored energy to offset loads during peak periods.
- + Reduce site demand (utility net meter) when dispatched by utility based on system conditions (e.g. CPP). Export excess available energy.
- + System - avoided generation marginal cost.
- + Consumer - billing savings.

#### 4.1.1.1 *Success Criteria*

- + TOU

- Charge battery using PV during off-peak - Capture the PV generated off-peak by charging the battery to full capacity.
- Net export during peak - Use the off-peak generated PV to offset loads or export to the grid during peak periods. Dispatch PV generation and dispatch battery from approximately 90% state of charge (SOC) to 40%.

+ CPP

- Net export during peak - Reduce UPS to minimum (currently leaving at least 15% of available battery capacity for UPS at end of the on-peak period).

+ TOU and CPP

- Zero net imports across the peak period
- Reservation for back-up power – 2500R Midtown homeowners were promised backup power at all times, even during and after a DR event. At least 15% of battery capacity after CPP events, and 30% after TOU peak periods was reserved for backup.

#### 4.1.1.2 *Summer TOU-CPP Test Events and Results*

TOU-CPP pilot rate implemented for this pilot was applicable to months June through September. The TOU rate was in place on all non-holiday weekdays from 4-7 pm on non-CPP event days. The CPP rate was in place as called by SMUD during the same time period and would override the TOU rate at that time. The peak period for both TOU and CPP was exactly three hours. The tariff allows for up to 12 CPP events per summer. For the 2015 demonstration, there were a total of nine CPP events, and the remaining non-holiday, summer weekdays were on a TOU rate.

Due to the fixed nature of the rate structure, both Sunverge and enrolled SMUD customers received notice of TOU periods at the time of recruitment. Notice of CPP events was delivered to both Sunverge and enrolled SMUD customers by email at least 24 hours in advance. CPP events were called by SMUD demand response department on days of estimated high temperatures, particularly high demand, or system emergencies. Table 4-1 lists the Summer CPP events.

**Table 4-1. Summer Critical Peak Pricing Events.**

Event Number	Event Date
1	6/25/15
2	6/26/15
3	6/30/15
4	7/16/15
5	7/28/15
6	7/29/15
7	7/30/15
8	9/10/15
9	9/11/15

#### 4.1.2 FALL DRMS INTEGRATION USE CASE TEST (OCTOBER – NOVEMBER 2015)

The project sought to demonstrate the ability to integrate residential-sited storage with a utility demand response management system (DRMS). Sunverge worked with SMUD to develop a Sunverge SIS integration with SMUD's DRMS using the OpenADR 2.0a protocol. This strategy directly aligns with SMUD's strategy is to embrace open standards wherever reasonable to encourage interoperability of devices. This was a key implementation decision, because it provides SMUD a cost-effective resource that fits into their existing technology stack, alongside other assets.

In order to test the implementation of the DRMS integration, SMUD and Sunverge implemented a second set of demand response events dispatched in October and November. The DRMS and OpenADR module development was completed by October 2015, after the Summer TOU rate was no longer in effect. As a result, a demonstration of the DRMS integration required volunteers to participate in a testing period that gave Sunverge and SMUD access to battery capacities, while still leaving enough energy for backup power.

Volunteers were compensated with a \$100 Amazon gift card for agreeing to participate. Testing occurred over a two-month period with 20 total SIS units participating.

In order to ensure dispatchability test closely matched real dispatch scenarios, event criteria and event dispatch days were selected by SMUD to represent a variety of weather, temporal, and consecutive demand response event scenarios.

#### 4.1.2.1 ***Use Case Test Goals***

- + Demonstrate DRMS OpenADR communications
- + Demonstrate advance scheduled and emergency DR events with measures of performance consistency and forecast capacity
- + Demonstrate reduced utility grid impact while maintain shared customer benefit with back-up power

#### 4.1.2.2 ***Success Criteria***

The performance of these tests were evaluated with the following criteria:

- + Successful operation of OpenADR protocol – Event signal was received and operated according to the test plan outline (See Table 1).
- + Zero net imports – The fleet of SIS units dispatched energy for the entirety of the event period, and no grid power was demanded.
- + Reservation for back-up power – Sunverge promised the 2500R Midtown homeowners that at least 30% of the battery capacity would be reserved for backup power at all times, even during and after a DR event.
- + Grid export (load) flattening - Aggregated export power will meet forecast target and stay within a margin of error of +/- 300W per unit (due to inverter accuracy limitations), based on 15-minute averages. For example, in the first event, the target was 22.5 kW (aggregated) and the success band ranged between 16.5 kW to 28.5 kW (+/-6kW = +/-300W \* 20 units). Load flattening is important for providing SMUD with exported load predictability.
- + Limit ramping - The ramp up period was limited to less than 1500W/unit or 30kW total during the first 15 min of the event. Ramp down period was designed to occur gradually at the end of the

event as the battery neared the minimum SOC limit. This criterion was removed for the last 3 tests, since it was not deemed to be a high priority for SMUD.

#### 4.1.2.3 *Fall DRMS Integration Test Events and Results*

There were a total of eight simulated DR events that were called throughout October and November 2015. Each event was called using OpenADR payload “0” for the Distribution peak load shaving program. Table 4-2 briefly describes the unique elements of each test. Events 9-13 were done to test various operational and technical functionalities related to the OpenADR integration. The Grid Export Flattening operational functionality was tested in all events while the Ramping operational functionality was only tested in some events. Events 14-16 replicated CPP events called during the summer (i.e. 4-7pm Peak Period, day-ahead signal), so Sunverge could test and improve dispatch algorithms and capacity forecast accuracy.

**Table 4-2. Fall Demand Response Test Events.**

Event Number	Event Date	Advanced Notification	Event Period	Ramping Control?	Technical Tests
9	10/12/15	Day of	1 pm – 7 pm	Yes	<ul style="list-style-type: none"> <li>• DRMS OpenADR Communications</li> <li>• Capacity available over extended event period</li> </ul>
10	10/21/15	Day ahead	5 pm - 7 pm	Yes	<ul style="list-style-type: none"> <li>• Multiple event executions in one day</li> </ul>
11	10/21/15	Day of	3 pm - 5 pm	Yes	<ul style="list-style-type: none"> <li>• Multiple event executions in one day</li> <li>• New events can be received while an event is occurring</li> <li>• Capacity forecast accuracy</li> </ul>
12	10/26/15	10 minutes ahead	4 pm – 5 pm	No	<ul style="list-style-type: none"> <li>• Multiple event notifications in one day</li> <li>• Quick response to emergency DR event</li> <li>• Capacity forecast accuracy</li> </ul>
13	10/27/15	Day ahead	4 pm – 7 pm	Yes	<ul style="list-style-type: none"> <li>• Multiple event notifications in one day</li> <li>• Capacity forecast accuracy</li> </ul>
14	11/11/15	Day ahead	4 pm – 7 pm	No	<ul style="list-style-type: none"> <li>• Algorithm optimization</li> <li>• Performance consistency</li> <li>• Capacity forecast accuracy</li> </ul>
15	11/12/15	Day ahead	4 pm – 7 pm	No	<ul style="list-style-type: none"> <li>• Algorithm optimization</li> <li>• Performance consistency</li> <li>• Capacity forecast accuracy</li> </ul>
16	11/16/15	Day ahead	4 pm – 7 pm	No	<ul style="list-style-type: none"> <li>• Algorithm optimization</li> <li>• Performance consistency</li> <li>• Capacity forecast accuracy</li> </ul>

Each DR test event was evaluated on these success criteria and graded. The results are shown in Table 4-3 below.

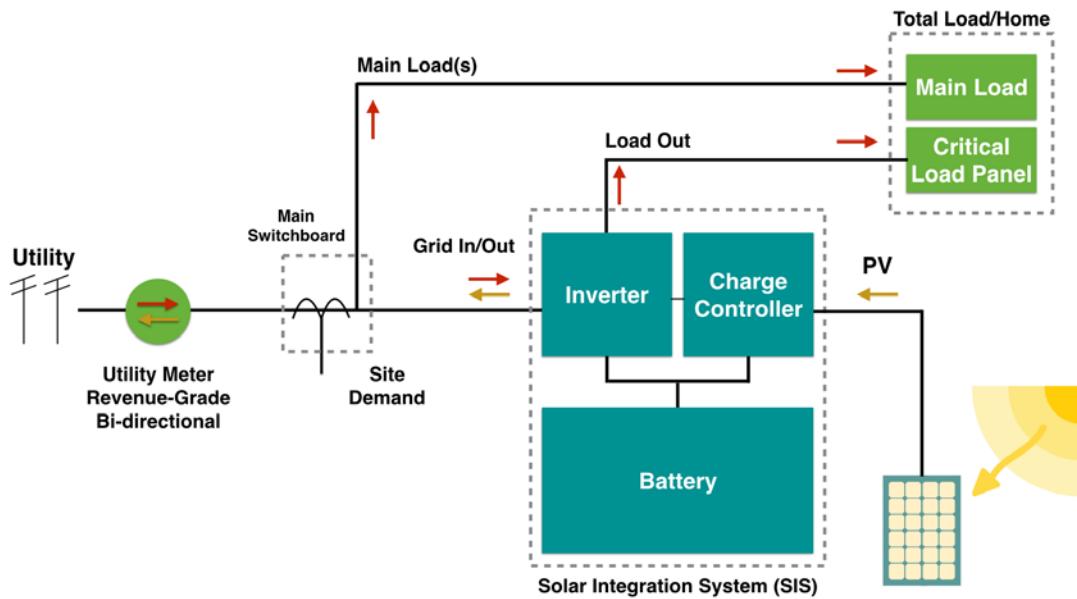
**Table 4-3. Fall 2015 DR Test Event Results.**

Success Criteria	Event							
	9	10	11	12	13	14	15	16
<b>Successful operation of OpenADR protocol</b>	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass
<b>Zero net imports</b>	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass
<b>Reserve battery for back-up power</b>	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass
<b>Limit ramping</b>	Pass	Pass	Pass	Pass	Pass	Pass	Pass	N/A
<b>Load flattening</b>	Fail	Pass	Fail	Fail	Pass	Fail	Fail	Fail
<b>Score (% Pass)</b>	80%	100%	80%	80%	100%	80%	80%	75%

#### 4.1.3 SIS KW LOAD IMPACTS

The impact of SIS units on the net site demand at the point of metering is analyzed for participants and non-participants. The impacts of having an SIS unit and being on a TOU CPP rate tariff were examined. For each household, minute by minute data was gathered on all power flows measured by the SIS. This data included the net site demand at the point of metering as well as enough information to calculate what the net site demand would have been if PV generation had been installed without an SIS unit. The total SIS consumption includes the main load and critical loads of the home. Net exports are pushed out to the grid, allowing the homeowner to receive bill credit for their excess energy generation.

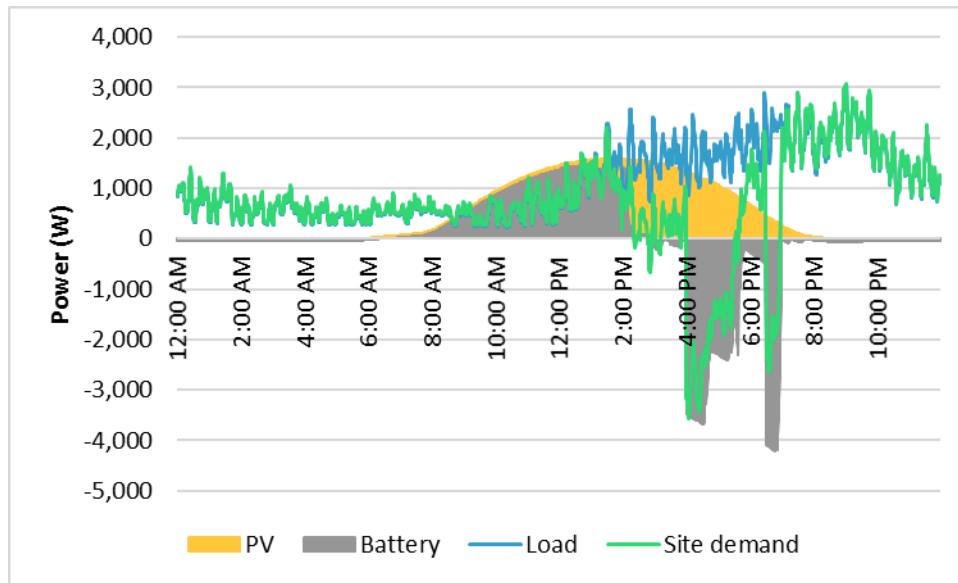
Figure 4-2. SIS Power Flow Diagram.



#### 4.1.3.1 *Load Impacts During Summer 2015 TOU-CPP Events*

Figures Figure 4-3 and Figure 4-4 give an example of the minutely data that was collected and analyzed for the summer 2015 TOU-CPP event on June 26<sup>th</sup>. These figures show the average values across all participants and non-participants for PV generation, battery charging, gross site load, and net site demand. The SIS units of the program participants charge from solar power in the morning and then discharge during the critical peak period between 4pm and 7pm. The SIS units of the non-participants charge their batteries from solar in the early morning, topping off the battery. This topping off is necessary in order to maximize the battery energy that can be discharged during the peak period. After fully charging the battery at close to 2pm, the energy is stored in the battery until it is allowed to dispatch during the peak period. The PV generated continues to supply the loads at the home, and net generation is exported to the grid for net metering credit.

**Figure 4-3. Average TOU-CPP Program Participant Power Flows on June, 26<sup>th</sup> 2015.**



**Figure 4-4. Average Non-Participant Power Flows on June, 26<sup>th</sup> 2015.**

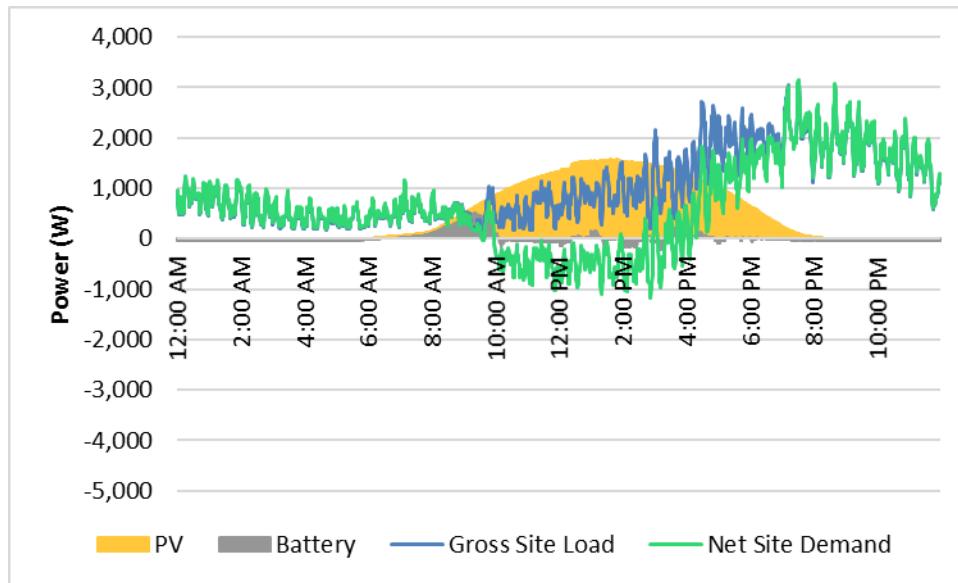


Table 4-4 shows the average reduction in net site demand at the point of metering with an SIS installed versus what it would have been with only PV generation installed during the summer 2015 conservation days. The average reduction is given for each conservation day event, separately for TOU-CPP participants and non-participants. The difference in average load reduction between TOU-CPP participants and non-participants is given for each hour and event. Program participant households show an average load reduction of 2.2 kW during critical peak events. Households that were not program participants, however,

have a small negative reduction (increase) in load during the critical peak hours compared with what their load would have been with only PV installed.

**Table 4-4: Average Reduction in Net Site Load During Summer CPP Events**

Event Date	Participation	Average Reduction in Net Site Load (W)			
		Hour Beginning			Event Average
6/25/2015	Non-Participants	-137	-108	-136	-127
	Participants	2,828	1,386	1,817	2,010
	Difference	2,965	1,494	1,953	<b>2,137</b>
6/26/2015	Non-participants	-95	-200	-98	-131
	Participants	2,858	1,739	2,287	2,295
	Difference	2,953	1,939	2,385	<b>2,426</b>
6/30/2015	Non-participants	-100	-103	-113	-105
	Participants	2,890	2,114	1,952	2,319
	Difference	2,990	2,217	2,065	<b>2,424</b>
7/16/2015	Non-participants	-39	-64	-169	-91
	Participants	2,785	1,990	1,998	2,258
	Difference	2,824	2,054	2,167	<b>2,348</b>
7/28/2015	Non-participants	-38	-31	-90	-53
	Participants	2,801	1,987	1,977	2,255
	Difference	2,839	2,018	2,067	<b>2,308</b>
7/29/2015	Non-participants	-123	-72	-85	-94
	Participants	2,898	2,017	1,811	2,242
	Difference	3,021	2,089	1,896	<b>2,336</b>
7/30/2015	Non-participants	-205	-51	-120	-125
	Participants	2,963	2,076	1,681	2,240
	Difference	3,168	2,127	1,801	<b>2,365</b>
9/10/2015	Non-participants	-103	-110	-146	-120
	Participants	2,019	2,583	1,928	2,177
	Difference	2,123	2,693	2,074	<b>2,297</b>
9/11/2015	Non-participants	-82	-124	-133	-113
	Participants	1,637	732	2,746	1,705
	Difference	1,719	855	2,879	<b>1,818</b>

The larger reduction in net site load by participants is driven by the use of the SIS battery to discharge during CPP events. Table 4-5 shows the average daily energy generated by PV for both participants and non-participants during CPP event days. The table also shows the total daily energy discharged from the storage units averaged over both participants and non-participants. This table shows that on average, PV at participant homes generated slightly more energy than PV at non-participant homes. The majority of the difference between net site load at participant and non-participant homes however is due to energy

discharged from the SIS units. The SIS units at participant homes discharged on average between 5,400 and 7,000 Wh more during CPP event days than those at non-participant homes.

**Table 4-5. Average Daily Energy Generation During Summer CPP Event Days.**

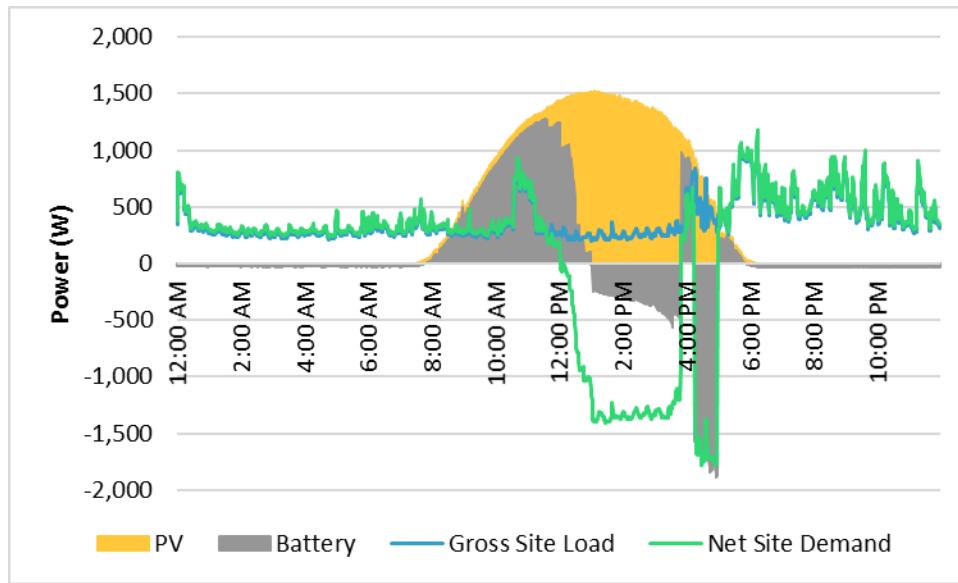
Event Date	Participation	Daily PV (Wh)	Daily SIS Discharge (Wh)
6/25/2015	Non-Participants	11,934	1,158
	Participants	12,485	7,251
	Difference	551	6,093
6/26/2015	Non-participants	12,415	1,085
	Participants	12,736	7,958
	Difference	321	6,873
6/30/2015	Non-participants	10,878	1,076
	Participants	11,785	8,052
	Difference	907	6,976
7/16/2015	Non-participants	12,420	1,088
	Participants	12,758	7,789
	Difference	338	6,701
7/28/2015	Non-participants	12,261	1,168
	Participants	12,767	7,870
	Difference	506	6,702
7/29/2015	Non-participants	11,543	1,170
	Participants	12,347	7,755
	Difference	804	6,585
7/30/2015	Non-participants	11,449	1,014
	Participants	11,694	7,713
	Difference	245	6,699
9/10/2015	Non-participants	9,817	783
	Participants	10,328	7,726
	Difference	511	6,943
9/11/2015	Non-participants	8,310	745
	Participants	8,286	6,167
	Difference	-24	5,422

#### 4.1.3.2 *Load Impacts During Fall 2015 OpenADR Events*

Figures Figure 4-5 and Figure 4-6 give an example of the minutely data that was collected and analyzed for the fall 2015 OpenADR demand response event on October 26<sup>th</sup>. On this day, a demand response event occurred between 4 pm and 5 pm. Using OpenADR, an event signal was created 10 minutes before the start of the DR event, prompting the test units to dispatch. The SIS units of the program participants charge from solar power in the morning and then discharge at between 250 W and 500 W starting at 1 pm. Once the SIS units are notified of the demand response event, they begin charging. The units continue to charge until 4:15 pm, and then discharge for the remainder of the hour. When the event concluded at

5 pm, the batteries charged from the available solar power to increase the energy available for providing backup.

**Figure 4-5. Average Program Participant Power Flows on October, 26<sup>th</sup> 2015.**



Non-participant SIS units maintain full battery capacities for backup power usage. Batteries charge from PV, but once the batteries reach a full state of charge, the PV power is used by the homes loads and net generation is exported to the grid for net metering credit. The SIS units are biased to discharge at 300W in order to offset inverter measurement errors and guarantee that the battery does not charge again before 8 pm. Additionally, the SIS units engage in PV smoothing, which results in a slowly increasing discharge power. The discharging power reaches a maximum of roughly 600 W near 5 pm and then maintains a fairly constant output until 8 pm. Participant SIS units operate similarly to non-participant units in that the battery charges to full and dispatches net PV prior to a DR event. During a DR event, participating units dispatch battery and PV power.

Figure 4-6. Average Non-Participant Power Flows on October, 26<sup>th</sup> 2015.

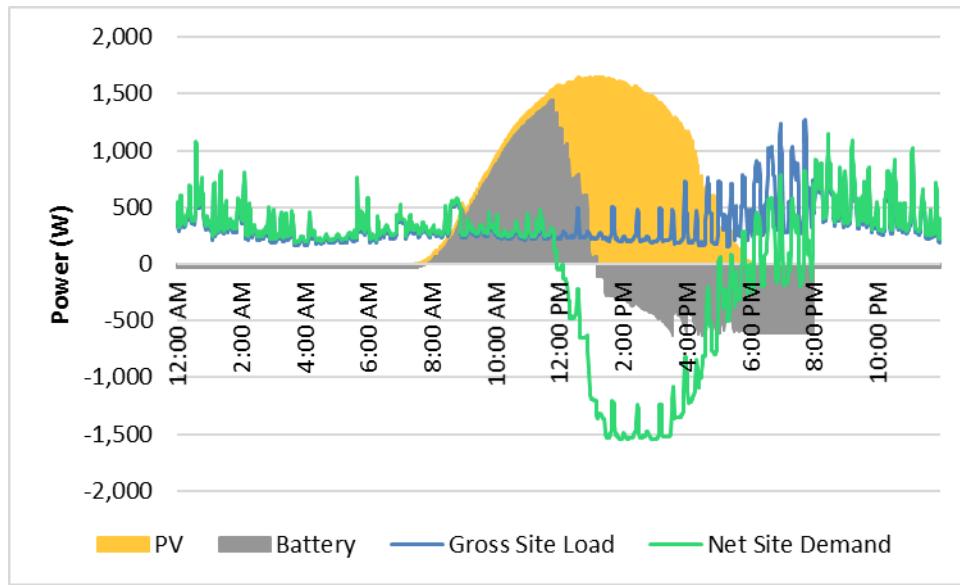


Table 4-6 shows the average reduction in net site demand at the point of metering with an SIS installed versus what it would have been with only PV generation installed during the fall 2015 demand response events. The average reduction is given for each conservation day event, separately for participants and non-participants. The difference in average load reduction between participants and non-participants is given for each hour and event. Program participant households show an average load reduction of 1.4 kW during demand response events. Households that were not program participants, had a smaller average load reduction of 285 W during the demand response events. The length of the DR events and the timing of the notifications for the DR events varied as described in Table 4-2. Reduction in net site load is only shown for hours during DR events although the SIS unit may be discharging according to the algorithm during other hours of the day.

**Table 4-6. Average Reduction in Net Site Load During Fall 2015 Demand Response Events.**

Event Date	Participation	<u>Average Reduction in Net Site Load (W)</u>						
		<u>Hour Beginning</u>						Event Average
		13	14	15	16	17	18	
10/12/2015	Non-Participants	-89	54	-236	120	87	127	10
	Participants	-31	300	468	617	1,057	1,184	599
	Difference	58	246	705	498	970	1,057	<b>589</b>
10/21/2015	Non-Participants			291	313	391	369	341
	Participants			478	1,261	504	1,865	1,027
	Difference			187	948	113	1,496	<b>686</b>
10/26/2015	Non-Participants			335				335
	Participants			940				940
	Difference			605				<b>605</b>
10/27/2015	Non-Participants			-156	-58	-26		-80
	Participants			1,383	2,036	1,529		1,649
	Difference			1,539	2,094	1,556		<b>1,729</b>
11/11/2015	Non-Participants			445	466	459		457
	Participants			504	2,064	2,054		1,541
	Difference			59	1,598	1,595		<b>1,084</b>
11/12/2015	Non-Participants			502	472	469		481
	Participants			2,035	2,668	1,190		1,964
	Difference			1,532	2,196	721		<b>1,483</b>
11/16/2015	Non-Participants			506	425	426		452
	Participants			2,275	2,353	1,107		1,912
	Difference			1,769	1,928	681		<b>1,459</b>

Table 4-7 shows the average daily energy generated by PV for both participants and non-participants during DR event days. The table also shows the total daily energy discharged from the storage units averaged over both participants and non-participants. During the fall 2015 events, there is generally less energy available from PV compared with during the summer 2015 events. Also, there is much more energy discharged from non-participant SIS units during the fall 2015 events than during the summer 2015 events. It is also important to note that the fall participants and non-participants are not the same sets of households as in the summer.

The largest differences between participant and non-participant SIS units occur on October 26<sup>th</sup> and October 27<sup>th</sup>. These differences are due to the two DR event notifications sent on October 26<sup>th</sup> and the low solar PV output on October 27<sup>th</sup>. Participant units discharge for a shorter than usual one hour DR event on October 26<sup>th</sup> and then charge their batteries for another event the next day, resulting in an unusually low SIS discharge energy for the day. The non-participant units discharge 1,289 Wh more than participant units on this day. On the 27<sup>th</sup>, there is very little solar power available, and so the non-

participant batteries charge from the available PV without reaching the threshold where they would begin to discharge. The non-participants discharge a small amount of power due to vampiric load. But, since the participant SIS units discharged little the day before, they have stored energy available to discharge on October 27<sup>th</sup>.

**Table 4-7. Average Daily Energy Generated During Fall 2015 Demand Response Event Days**

Event Date	Participation	Daily PV (Wh)	Daily SIS Discharge (Wh)
10/12/2015	Non-Participants	11,023	1,750
	Participants	10,563	5,203
	Difference	-460	3,453
10/21/2015	Non-participants	11,346	3,409
	Participants	10,046	5,387
	Difference	-1,300	1,978
10/26/2015	Non-participants	10,725	3,599
	Participants	9,804	2,319
	Difference	-921	-1,280
10/27/2015	Non-participants	2,643	544
	Participants	2,516	5,768
	Difference	-127	5,224
11/11/2015	Non-participants	10,292	4,655
	Participants	9,097	5,804
	Difference	-1,195	1,149
11/12/2015	Non-participants	10,495	4,730
	Participants	9,471	6,828
	Difference	-1,024	2,098
11/16/2015	Non-participants	10,811	4,900
	Participants	9,658	6,885
	Difference	-1,153	1,985

## 4.2 Distribution System Modeling

### 4.2.1 SMUD DISTRIBUTION RESOURCE PLAN

Every year SMUD updates its Distribution System Plan over a five-yr. horizon. The Distribution System plan considers the past, current, and forecasted conditions to identify distribution system needs to maintain reliability and satisfactory power quality attributes. Proposed infrastructure projects take into consideration the tradeoff between investments and operational benefits while delivering safe and reliable electricity to customers. Historically this planning process considers traditional infrastructure

investments. This project presents a preliminary attempt to evaluate how Distributed Energy Resources (DER), namely the residential scale Sunverge SIS that combines battery storage with solar panels, may defer traditional infrastructure projects. The modeling sections of this report reflect the plans in the 2015 Distribution System Five-yr. Plan.

#### **4.2.2 SMUD PV, EE, DR, EV MARKET FORECAST**

The load forecast and market forecast for DERs (PV, EE, DR, and EV) are maintained by the Load Research and Forecasting group in SMUD's Business Planning Department. The base load forecast is developed from historical load adjusted for new development and customer changes that have been communicated to SMUD. The market forecast of individual DERs is developed by SMUD's Distributed Energy Strategy department and takes into consideration market growth over time as well as geographic dispersion. The first such forecast was prepared in 2015 with the help of Black and Veatch in the integrated DER dispersion analysis.

#### **4.2.3 FEEDERS SELECTED FOR MODELING**

Not all infrastructure projects from the SMUD Distribution System Plan were necessarily candidates for deferment through targeted residential storage plus solar deployment. There were two primary criteria: 1) Projects that were facing capacity constraints at the substation or feeder level due to load growth; and 2) Projects that had a relatively substantial residential load where a meaningful uptake of residential integrated storage and solar was possible. The following two projects were modeled:

##### **4.2.3.1 *Deferment of Jackson-Sunrise transformer upgrade***

**Base scenario:** In order to save O&M costs for a customer-owned substation, one industrial customer is planning to switch from 69 kV service to the more typical 12 kV commercial service. Residential load currently accounts for about 69% of the peak load on this substation. However, after the addition of this industrial customer, the residential load will account for only 35% of the forecasted peak load. This commercial customer has a peak apparent power consumption of about 3.5 MVA and peak real power consumption of about 2.4 MW. The local 12 kV substation currently has a 6.25 MVA transformer which would be pushed past the peak planning capacity by the 3.5 MVA growth in late 2016 or early 2017 therefore requiring an upgrade to the next size of 12.5 MVA at a cost of about \$750,000.

**Deferment scenario:** Evaluate the potential to delay the upgrade of the 6.25 MVA transformer to 12.5 MVA after deployment of distributed solar and storage, served by the Jackson-Sunrise substation.

**Changes in the Five-yr. Plan:** The 2016 Draft Distribution System Five-yr. Plan revises the base project description. Further analysis revealed that through two switch changes, Jackson-Sunrise could have partial load transfer to an adjacent substation, thereby eliminating the need for a transformer upgrade. The deferment analysis that follows shows value if such a switching change were not an option.

#### 4.2.3.2 *Deferment of Waterman-Grantline substation capacity upgrade*

**Base scenario:** Load growth is forecasted in the Union Park Industrial area served by the Waterman-Grantline substation. The Waterman-Grantline substation currently has a single 20 MVA transformer and a peak load of about 11 MVA among the three feeders it serves. This peak load is forecasted to grow to about 33 MVA over the next 10 years. Under the current forecast, between 2020-2021 a second 20 MVA transformer would need to be added for this load growth and to support N-1 contingency (distribution system redundancy for continued service in the event of a single point of failure). The cost of this project would be about \$2,300,000.

**Deferment scenario:** Evaluate the potential delay of the transformer addition after adding residential distributed solar and storage, served by Waterman Grant substation.

**Changes in the Five-yr. Plan:** The 2016 Draft Distribution System Five-yr. Plan revises this load growth forecast to a slower pace. Under the new load growth forecast, this traditional project is no longer projected for the five-yr. horizon. The 2015 assumptions are used to model this project.

#### 4.2.4 LOAD/PENETRATION SCENARIOS MODELED

The load forecasts were derived from the Load Research and Forecasting group at SMUD for the system and respective local network. The solar penetration (PV market size in capacity and installations) uses actual data for 2015. The 2020 and 2030 forecasts are boundary scenarios identified in the Black & Veatch DER penetration and dispersion study. (Butler, Bartholomy, Olson, & Waldren, May 2016) The assumptions are summarized in Table 4-8.

**Table 4-8: Load and PV Market Size Forecasts Modeled (only constrained nodes for projects)**

Location	Year	Capacity			Customer Count		
		Total Peak (1 in 2) / % of 2015 substation capacity	Res. Peak (coincident)	Res. PV (high adoption, non- coincident)	Total	Res.	PV (high adoption)
System	2015	2,909 MW / NA	1,747 MW	45 MW	616,000	547,000	11,000
	2020	2,945 MW / NA	1,767 MW	107 MW	647,000	574,000	18,000
	2030	3,144 MW / NA	1,893 MW	226 MW	720,000	641,000	38,000
Jackson-Sunrise	2015	2,442 kW / 39%	1,683 kW	158 kW	484	314	21
	2020	5,003 kW / 80%	1,763 kW	315 kW	504	329	37
	2030	5,170 kW / 83%	1,972 kW	437 kW	548	368	47
Waterman- Grantline	2015	10,661 kW / 53%	6,660 kW	173 kW	2,064	1,728	36
	2020	17,105 kW / 86%	10,926 kW	813 kW	3,299	2,824	129
	2030	31,360 kW / 157%	20,394 kW	1,056 kW	6,057	5,279	179

## 4.2.5 ANALYSIS OF DISTRIBUTION SYSTEM OPERATIONS

### 4.2.5.1 *Objectives of the analysis*

This analysis was designed to support estimation of avoided costs on the local distribution system considering the operational impacts of PV and SIS units. Using a combination of RMI's Electricity Distribution Grid Evaluator (EDGE) model along with EPRI's OpenDSS tool, RMI modeled a single subsection of SMUD's distribution system to serve as a sample of the location-specific physical and electrical impacts experienced by a distribution system as a result of the addition of PV-integrated distributed energy storage.

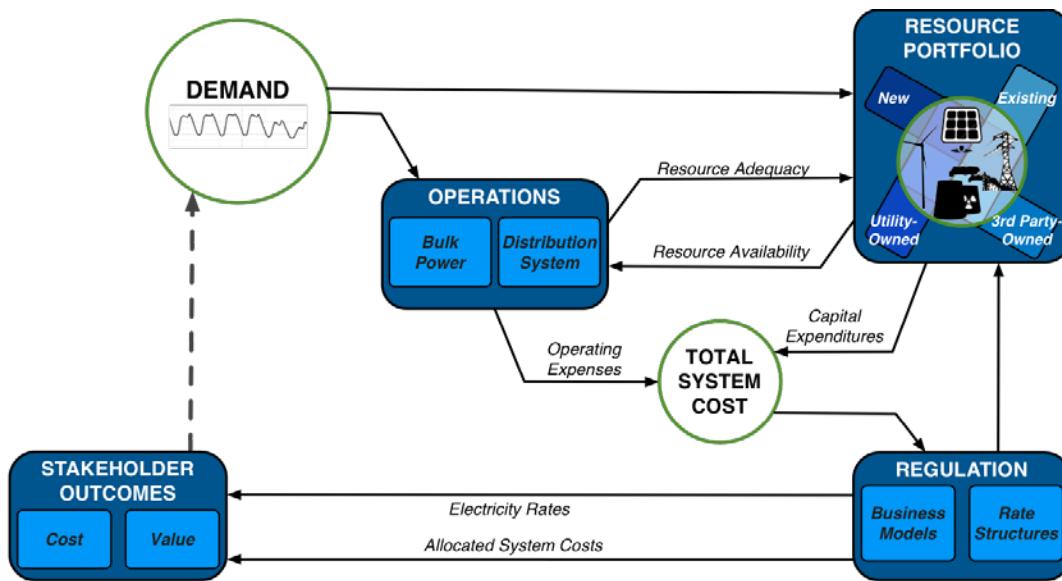
### 4.2.5.2 *Approach—Models Used*

#### About the EDGE model

RMI's Electricity Distribution Grid Evaluator (EDGE) model is a MATLAB-based simulation tool for evaluating and optimizing the net value proposition of DERs (Sherwood & Lacy, 2014). The EDGE model provides an analytical basis for assessing the benefits and costs created by system resources, including DERs, by incorporating the principal drivers of value in electricity system planning and operations—

location, timing, and controllability. The model can consider decision-making and impacts at multiple levels of the system planning and operations processes, but for this analysis the model's scope was limited to distribution system operations. Figure 4-7 shows an overview of the modules in the full EDGE model; the distribution system operations module was used for this analysis.

**Figure 4-7. Overview of Structure and Modules in the EDGE Model.**

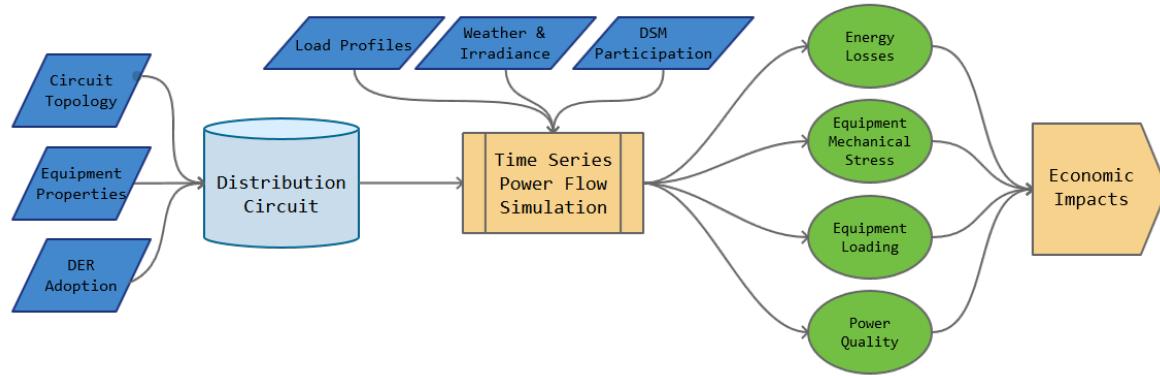


The distribution system operations module of the EDGE model performs a detailed assessment of the technical and operational implications of a given set of distribution-level resources and infrastructure. To do this, EDGE integrates EPRI's Open Distribution System Simulator (OpenDSS)—a comprehensive open source electrical system simulation tool for utility distribution systems—to perform quasi-static time series power flow simulations of circuit operations (Broderick, Reno, Ellis, Smith, & Dugan, 2013).<sup>12</sup> Circuit operations are simulated for a full year at 15-minute intervals for a business-as-usual scenario (which is used as a benchmark) and for the various PV and SIS scenarios described in the following sections. From these simulations, EDGE captures the dynamic, localized effects on the system's physical performance in terms of the specific metrics (such as voltage, equipment operation, energy losses, etc.) during normal

<sup>12</sup> A quasi-static time series power flow simulation “produces sequential steady state power flow solutions where the converged state of an iteration is used as the beginning state of the next.” (Broderick, Quiroz, Reno, Ellis, Smith, & Dugan, 2013).

conditions.<sup>13</sup> Figure 4-8 shows a simplified flowchart of the distribution system analysis performed using the EDGE model.

**Figure 4-8. Simplified Flowchart of Distribution System Analysis Using the EDGE Model.**



The PV output from specific installations is modeled within EDGE using the PV\_LIB toolbox for MATLAB, developed by Sandia National Laboratories. The PV\_LIB toolbox implements a set of robust and validated PV modeling methods that use weather data inputs (including solar irradiance, ambient temperature, pressure, and wind speed) to simulate the hourly or sub-hourly power output from a PV system (Stein, 2012).

### Storage algorithms

The algorithms used by the EDGE model for this analysis for charging and discharging the SIS units were developed based on:

- + Algorithms used in Sunverge's 2015 demonstration, including the Predictable Dispatch use case where the SIS unit's battery is charged from PV during the day, and discharged during the evening to meet much of the home's load, flattening the profile seen by the grid. For this algorithm, the batteries can only charge from PV and not from the grid and were required not to reduce the customer bill savings. This use case falls within the 'customer dispatch' category.
- + Algorithms used in E3's integrated modeling, including a use case aimed at minimizing the distribution peak, where individual SIS unit batteries are used to flatten the overall total peak load

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<sup>13</sup> This analysis does not model faults or reliability issues, such as short circuit contribution, protection equipment coordination, operation under contingency conditions, and unexpected changes to circuit configuration.

per feeder. For this algorithm, the batteries can charge from PV and from the grid, and use a PV forecast for the day to determine whether charging from the grid will be necessary. This use case falls within the ‘utility dispatch’ category.

### Operational impact metrics

The EDGE model compares the change in distribution system operation between the benchmark simulation and simulations for subsequent PV and SIS scenarios to determine the impacts (detrimental or beneficial) attributable to the addition of those DERs. Physical and electrical impacts can be quantified and measured in terms of several key indicators:

#### + Energy Losses

- Energy losses on the distribution system increase with loading and congestion, and reduce the overall efficiency of the system. These losses directly increase operating costs by requiring additional energy to be generated or procured, but can be reduced by improved management of system operating conditions. In this analysis, the cumulative annual energy losses across the distribution circuit are modeled to estimate the impact of PV and SIS deployment.
- *Motivation:* Output from PV and SIS units should typically reduce the net load on the distribution circuit, therefore reducing distribution energy losses during those times. However, PV and SIS could potentially increase losses if SIS units are charged from the grid at times when PV output is lower than the charging demand.

#### + Equipment Mechanical Stress

- Mechanically switched equipment (i.e., tap-changing transformers, switched capacitor banks, and line voltage regulators) experience accelerated wear-and-tear with every switching operation, the need for which is a function of local circuit conditions. This physical degradation accumulates over time (with or without switching operations), eventually forcing repair or replacement of the equipment. In this analysis, the total number of annual switching operations for individual distribution equipment assets is modeled before and after the addition of PV and SIS.
- *Motivation:* If PV and SIS operation is aligned with the local loading characteristics that cause a switching operation, it may be possible to obviate the need for action by the switched equipment (and associated wear-and-tear). Conversely, if misaligned with local loading characteristics, PV and SIS operation could drive an increase in the need for switching operations.

## + Equipment Loading

- Thermal deterioration of materials in distribution system elements is largely a function of heat exposure. When these elements are subjected to power at or above rated levels, they will experience accelerated degradation of materials (e.g., transformers). Without corrective action, this may lead to premature failure of the element. Relatedly, some types of equipment have a finite lifetime that is related to the number of hours of use (e.g., capacitors). In this analysis, the quantity, magnitude, and duration of overload events are modeled, as is the number of hours of use of equipment.
- *Motivation:* As with energy losses, PV and SIS output should typically reduce the net load on equipment (and reduce thermal degradation of overloaded equipment), unless the SIS is charged from the grid at a level greater than PV output at a given time. As with equipment mechanical stress, if PV and SIS operation is aligned with the local loading characteristics that necessitate the use of equipment like capacitors, it is possible to reduce the number of hours that the equipment is operated (extending the equipment life). If misaligned, however, the PV and SIS operation could increase the hours of equipment use.

## + Power Quality

- Undesirable voltage fluctuations indicate inadequate voltage regulation and poor local power quality. If severe, this requires remediation in the form of system reconfiguration and/or new equipment. To estimate the impact of PV and SIS deployment, this analysis measures the quantity, magnitude, and duration of under-/over-voltage events.<sup>14</sup>
- *Motivation:* This metric is the planning equivalent to equipment mechanical stress. If existing equipment on a circuit (e.g., tap-changing transformers, switching capacitor banks, etc.) are insufficient to maintain satisfactory power quality, new equipment is planned for installation. Depending on how they are operated, PV and SIS units could obviate or defer the need for new distribution system equipment (or create the need for new distribution equipment) to maintain satisfactory power quality.

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<sup>14</sup>The industry standard for voltage, ANSI C84.1, prepared by the National Electrical Manufacturers Association, the range of acceptable service voltage is within plus or minus 5% of nominal. For this analysis, we consider over-voltage events to be when voltage exceeds 1.05 per unit, and under-voltage events to be when voltage falls below 0.95 per unit (ANSI CB4.1-2011)..

#### 4.2.5.3 **Approach—Key Inputs & Assumptions**

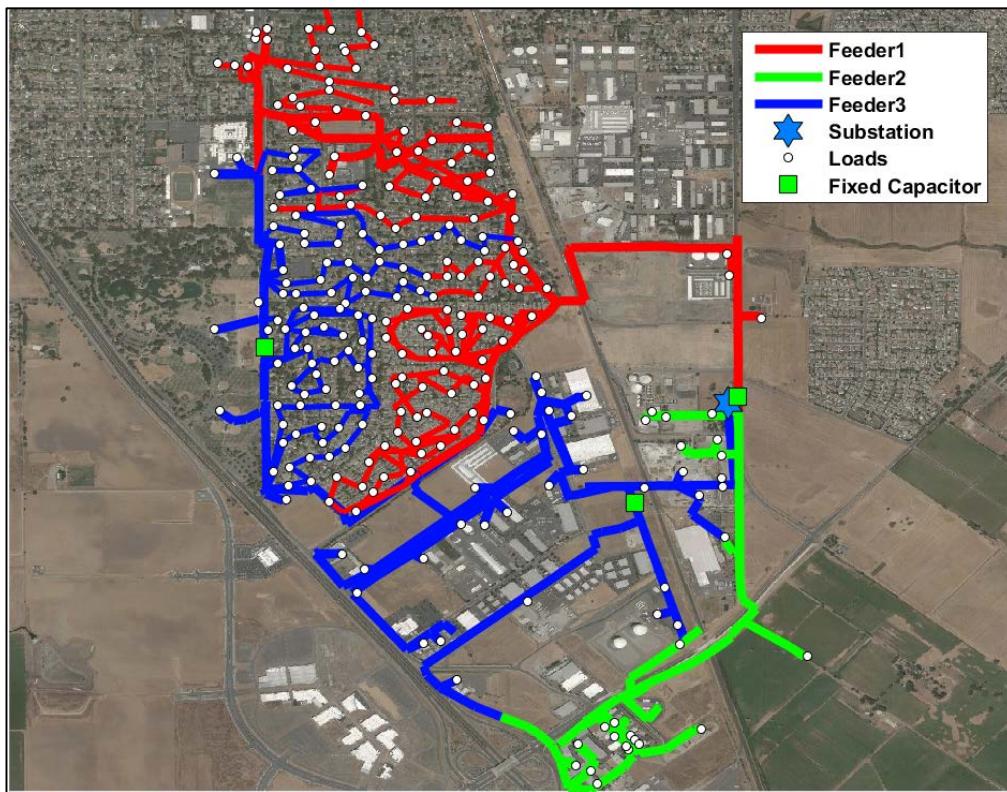
##### **Circuit model**

To simulate distribution system operations, OpenDSS requires a model of the circuit it is meant to represent. OpenDSS uses a unique file format (.dss) for specifying the characteristics and connectivity of circuit elements, which include infrastructure and equipment as well as loads and distributed generation. Each element is specified according to a different set of parameters (rated capacity, number of phases, bus connection, etc.), and a given circuit model may contain thousands of individual elements.

Of the two circuits outlined in section 4.2.3, this portion of the analysis considered only Project 2, the Waterman-Grantline circuit. While the initial intent with this analysis was to analyze a large and representative portion of SMUD’s distribution system, the project team encountered numerous challenges in creating accurate OpenDSS circuit models from SMUD’s existing distribution system models in Synergi Electric, a commercial distribution power flow software. The largest challenge was Synergi Electric’s faulty conversion function. SMUD’s software license included the ability to use a function that converts a Synergi model into OpenDSS format. However, when SMUD’s distribution engineers attempted to export the Waterman-Grantline circuit, the file had a large number of missing and erroneous circuit element definitions. Correcting and completing an OpenDSS model for the Waterman-Grantline circuit required extensive effort over a period of months between SMUD distribution engineers in collaboration with the RMI team to develop a functional and accurate model. While the team eventually succeeded in creating a circuit model for Waterman-Grantline, creating models for additional circuits was deemed to require more time than was available under this project, and efforts were focused on the Waterman-Grantline analysis.

The OpenDSS circuit model for the Waterman-Grantline circuit developed from SMUD’s existing models includes the Waterman-Grantline substation transformer and the three feeders that it serves (Figure 4-9). In addition to the substation transformer, the circuit has three capacitors: a 1200 kVAR capacitor on feeder 1, and two 600 kVAR capacitors on feeder 3. The circuit serves 2,018 metered customers, the majority of which (86%) are residential. These loads, as well as the net load impacts from DERs, were aggregated at the service transformer level (there are 276 service transformers on the circuit).

Figure 4-9. Map of the Waterman-Grantline circuit.



To verify the accuracy of the OpenDSS circuit model, power flow simulation results from OpenDSS for a single snapshot in time were compared against results for the same snapshot in Synergi. The voltage at each bus and current through each line were compared, and the error calculated relative to the Synergi results for each measurement. SMUD engineers judged the overall model to be close to exact, and the discrepancies between the model results to be well within error tolerances.<sup>15</sup>

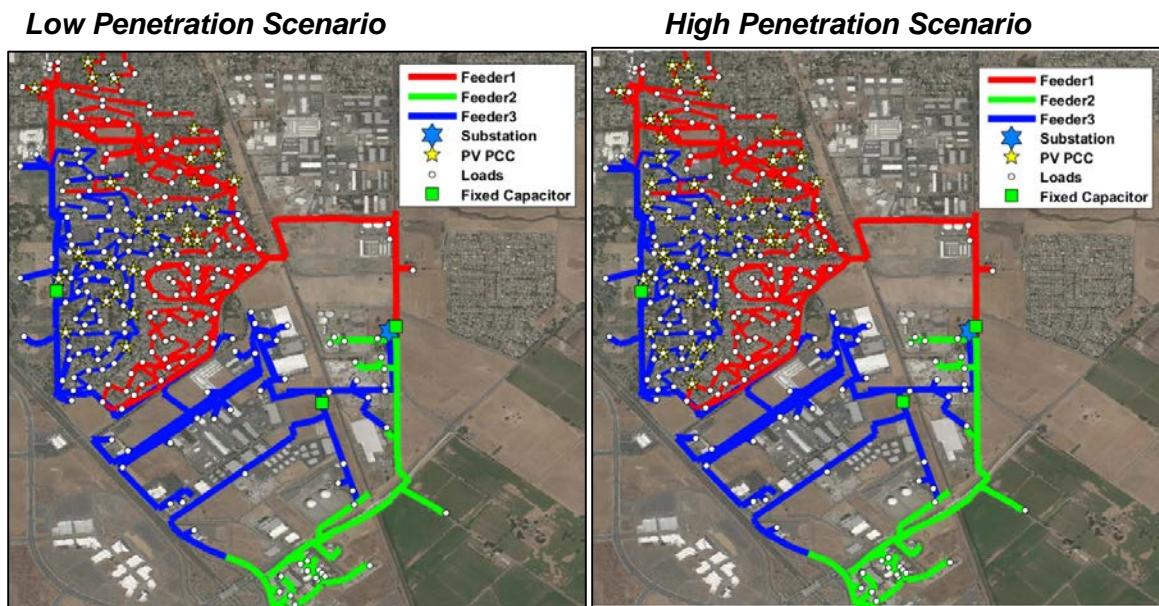
#### PV & SIS equipment

To model the output from PV and SIS units, inputs to the EDGE model included detailed technical specifications for PV modules, the system inverter, and SIS unit batteries. Specifications for the PV modules and inverter characteristics came from Sandia National Laboratories databases, while battery specifications were provided by Sunverge.

<sup>15</sup> Results from the two models: voltages are within 0.1% on average, while line currents are within 1.9% on average. The majority of the difference in results between each model was driven by areas of the circuit where very little power was flowing in the snapshot used as a benchmark (i.e., where current flow was less than 1 A).

In addition to the quantity and size of PV and SIS units deployed, modeling a circuit requires assumptions about where the units are interconnected. Because customer-level data that would help to establish each customer's likelihood to adopt new technology was not available, the project team chose to assume a random dispersion of units across residential customers on the circuit (Figure 4-10).

**Figure 4-10 Deployment of PV and SIS units in the low and high penetration scenarios.**



#### Load data

To accurately represent loading on the circuit, SMUD provided customer load data for all 2,018 meters on the circuit. This data includes all of calendar year 2015, and was collected from AMI to measure net energy consumption at hourly intervals for residential customers, and at 15-minute intervals for non-residential customers. SMUD also provided the hourly measured power factor for each feeder, which was applied evenly to all customers on that feeder (e.g., if the feeder power factor in a given hour was 0.95, then each customer on that feeder was assumed to have a power factor of 0.95). To standardize the datasets for use in the modeling analysis, hourly data was linearly interpolated to 15-minute intervals.

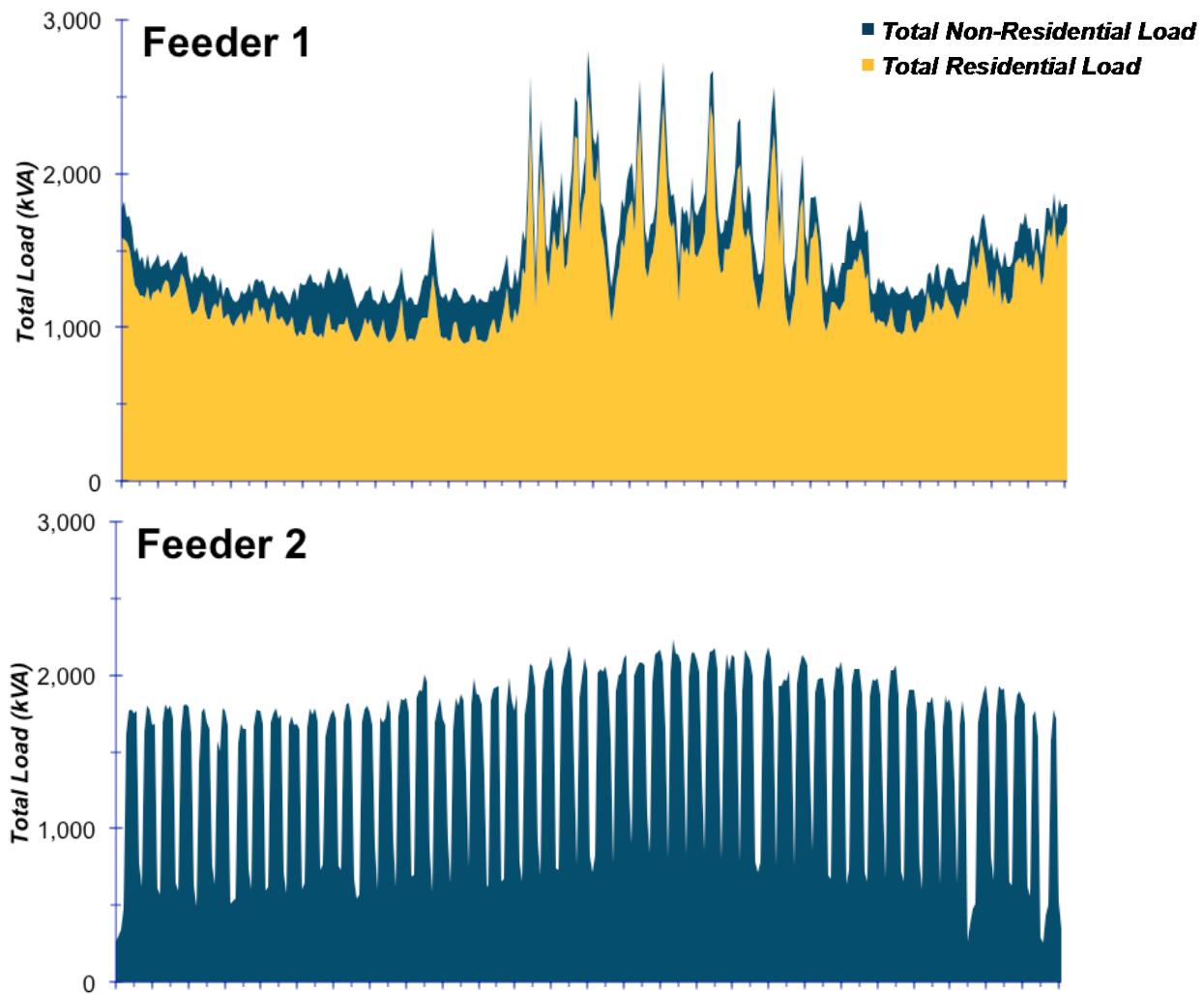
As shown in Figure 4-11, the feeders have very different loading profiles, both throughout the year and over the course of a given day. This is largely driven by differences in the types of load on each feeder. Feeder 1 serves mostly residential loads, while feeder 2 primarily serves commercial loads and feeder 3 serves a roughly even split of both residential and commercial loads. The commercial loads on the circuit have a distinctly different load shape than the residential loads, as they are more consistent (less "peaky") over the course of the year, but with significantly lower loading on weekends and holidays.

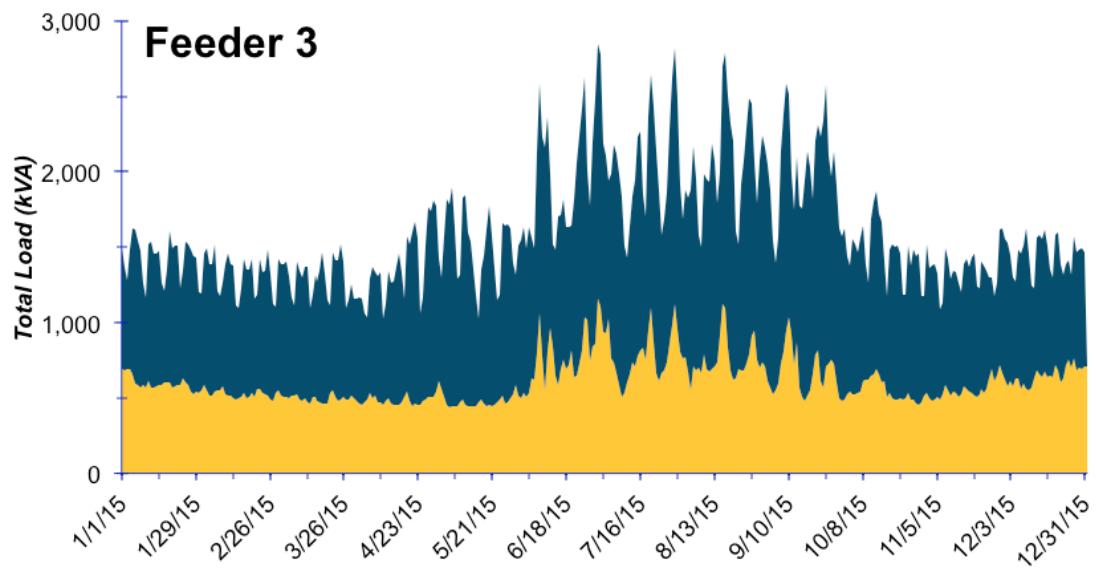
### Irradiance & weather data

To simulate accurate PV performance, location-specific time-synchronous weather data (irradiance, temperature, pressure, and wind speed) was used to match the time period of the load data provided by SMUD. Time-synchronous load and weather data is critical to accurately represent the interrelationship between weather and electricity use, specifically heating and cooling demand which is highly weather dependent.

Weather data inputs were compiled from two separate databases. Irradiance data for the Waterman-Grantline substation location was sourced from Clean Power Research's SolarAnywhere database (Perez, et al., 2015). This data included hourly satellite-derived solar irradiance for 2015 with a spatial granularity of 10 km by 10 km around the substation location. All other weather data components, including temperature, atmospheric pressure, and wind speed, were sourced from the National Oceanic and Atmospheric Administration's Quality Controlled Local Climatological Database (QCLCD) (US Department of Commerce), which provides high-quality hourly data from weather stations across the United States. The QCLCD weather station nearest to the circuit was used for this analysis, which was approximately 12 miles northeast of the substation at Sacramento Executive Airport.

Figure 4-11 Average Daily Load on Each Waterman-Grantline Feeder by Customer Type.





#### 4.2.6 POWER FLOW MODELING RESULTS

Using the tools and assumptions detailed in section 4.2.5, RMI conducted a quasi-static time series power flow analysis of the Waterman-Grantline circuit for one year (2015) at 15-minute intervals. This analysis evaluated the change in circuit operations in the context of several technology deployment scenarios: 1) with the addition of PV, 2) with the addition of PV with SIS units programmed for utility dispatch, and 3) with the addition of PV with SIS units programmed for customer dispatch. For each of these deployment scenarios, both a “low” penetration and “high” penetration case was modeled.

#### 4.2.6.1 *Summary of results*

**Table 4-9. Summary of Operational Impacts on the Waterman-Grantline Circuit in Each Scenario.**

	<u>Baseline</u>	<u>Low</u> <u>Penetration</u>			<u>High</u> <u>Penetration</u>		
		PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)
<b>ENERGY LOSSES</b>							
Total Annual Energy Losses (MWh)	343.0	341.4	341.0	341.2	339.6	338.9	339.2
Change in Total Annual Energy Losses (MWh)	-	-1.6	-2.0	-1.8	-3.4	-4.1	-3.8
<b>EQUIPMENT MECHANICAL STRESS</b>							
Total Annual Capacitor Switching Operations	116	134	134	134	134	134	134
Change in Total Annual Capacitor Switching Operations	-	18	18	18	18	18	18
<b>EQUIPMENT LOADING</b>							
Total Annual Hours of Capacitor Operation	14,126	6,279	6,279	6,279	6,279	6,279	6,279
Change in Total Annual Hours of Capacitor Operation	-	-7,847	-7,847	-7,847	-7,847	-7,847	-7,847
Annual Load Factor of Substation Transformer	35.4%	35.3%	35.3%	35.3%	35.2%	35.2%	35.2%
Change in Annual Load Factor of Substation Transformer	-	-0.1%	-0.1%	-0.1%	-0.2%	-0.2%	-0.2%
<b>POWER QUALITY</b>							
Total Annual Voltage Events	1,868	1,813	1,810	1,808	1,803	1,791	1,793
Change in Total Annual Voltage Events	-	-55	-58	-60	-65	-77	-75

As Table 4-9 shows, the addition of PV and SIS units to the circuit results in improved overall distribution circuit operations. In terms of energy losses, all scenarios reduced annual energy losses on the circuit by between 0.5–1.2% in both low and high penetration cases. In SIS scenarios, the utility dispatch use case results in greater improvement to energy losses than the customer dispatch use case. In terms of equipment mechanical stress, results show a slight (but insignificant) increase in capacitor switching operations. Equipment loading impacts were very different between metrics: while there was no significant impact on transformer loading (less than 0.2% and well below nameplate rating), the hours of capacitor operation were significantly reduced by over 50%. However, this reduction in hours of capacitor operation was achieved in the low penetration PV only case, with all other scenarios (i.e., adding SIS units or additional PV capacity) having no further impact on capacitor operations. Finally, power quality impacts were limited. There was a slight decrease in the number of voltage violation events (3–4%) in all scenarios, but the change is relatively insignificant (there may be opportunities for SIS units to better address voltage issues, which is discussed in section 4.2.6.5 below).

Impacts from the various PV and SIS scenarios along each of these operational metrics are explored in greater detail in the following sections. Their translation into value are then discussed in section 5.3.3.

#### 4.2.6.2 *Results—Energy Losses*

**Table 4-10. Total Annual Energy Losses Across the Circuit in Each Scenario.**

<u>Baseline</u>	<u>Low Penetration</u>			<u>High Penetration</u>			
	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	
<b>Total Annual Energy Losses (MWh)</b>	343.0	341.4	341.0	341.2	339.6	338.9	339.2
<b>Change in Total Annual Energy Losses (MWh)</b>	-	-1.6	-2.0	-1.8	-3.4	-4.1	-3.8
<b>Change Relative to 'PV Only' Scenario</b>	-	-	21.5%	12.3%	-	20.9%	12.7%

Annual energy losses, which include only losses on the circuit (not losses within the PV and SIS system), are reduced in all scenarios in which PV and SIS units are installed (Table 4-10). The addition of PV only—in both low and high penetration scenarios—serves to reduce the net load on the circuit in many hours, thereby reducing the power flow and associated losses. Losses are further reduced with the addition of SIS units under both utility and customer dispatch use cases. In both cases, the SIS units are charged at off-peak times when system loading is lower (and therefore losses are as well) and discharged at on-peak times when system loading is higher. By further reducing circuit loading at peak times, the SIS units drive a greater reduction in energy losses on the circuit. Compared to PV alone, the utility dispatch case achieves slightly greater loss reduction (21.5% at low penetration and 20.9% at high penetration) than the customer dispatch cases (12.3% at low penetration and 12.7% at high penetration) because the batteries are charged from both on-site PV and the grid, which maximizes their ability to discharge at times of peak loading.

#### 4.2.6.3 *Results—Equipment Mechanical Stress*

**Table 4-11 Annual number of capacitor switching operations in each scenario.**

Baseline		Low Penetration			High Penetration		
		PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)
<b>Annual Switching Operations for Capacitor #1</b>	112	112	112	112	112	112	112
<b>Annual Switching Operations for Capacitor #2</b>	2	0	0	0	0	0	0
<b>Annual Switching Operations for Capacitor #3</b>	2	22	22	22	22	22	22

The only mechanically-switched equipment on the Waterman-Grantline circuit are three line capacitors on feeders 1 and 2. As the results in Table 4-11 show, in the baseline scenario, two of the capacitors are switched only twice, while the other averages one switching operation every three days. This is affected by the addition of PV in the “low penetration” scenario. Capacitor 2 is no longer used (its switching operations are reduced from 2 to 0) and capacitor 3 is switched slightly more often (operations increase from 2 to 22), while the capacitor 1 is unaffected. None of the other scenarios (adding SIS and increasing the level of penetration) result in any additional changes in switching operations. Overall, the impact of

the addition of PV and SIS on capacitor switching for this circuit is minimal. While they may slightly increase the number of operations, the increase is insignificant and would be very unlikely to impact costs given the long lifetime (on the order of decades) of capacitors and the natural degradation that occurs regardless of switching.

The lack of additional switched equipment on this circuit is unfortunate from the perspective of gaining broader insight into the potential impact of PV and SIS units. While capacitor switching does result in wear and tear, the cost of replacing capacitor switches is relatively low, as the switch can be easily swapped with minimal effort (Cohen, 2012). Other types of switched equipment, such as transformer load tap changers (LTCs) and line voltage regulators, may be affected differently than capacitors when PV and/or storage is added to a circuit, and are typically much more expensive to repair or replace. To gain a better sense of how this equipment may be impacted by PV and SIS, future distribution system analyses by SMUD and other utilities can look to specifically target circuits that have LTCs and voltage regulators.

#### 4.2.6.4 *Results—Equipment Loading*

While the addition of PV and SIS units to the circuit had a limited effect on the number of capacitor switching operations, there was a much more significant impact on the hours of usage of the capacitors. Switching operations (discussed in section 4.2.6.3) and hours of capacitor usage impact operations and maintenance in different ways. Switching may lead to mechanical wear and tear of the switches within the capacitor unit, while hours of capacitor usage may accelerate the electrical and chemical degradation of the capacitor beyond its natural rate without any usage, thus shortening the unit's lifetime. As Table 4-12 shows, capacitor 3 sees a massive reduction in usage in each of the PV and SIS deployment scenarios—effectively, the capacitor unit goes from being used in 90% of the year to being used in < 1% of the year. The reduced need to operate the capacitor is due to the lower loading on feeder 3 (where capacitor 3 is located) as a result of adding PV and SIS capacity to the circuit. Given the change in need for capacitors 2 and 3 with the addition of PV and SIS, the useful life of the units could be extended, or they could potentially be relocated to another circuit (obviating the need for purchase of new equipment).

**Table 4-12 Annual hours of capacitor use in each scenario.**

	<u>Baseline</u>	<u>Low Penetration</u>			<u>High Penetration</u>		
		PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)
<b>Annual Hours of Operation for Capacitor #1</b>	6,239	6,238	6,238	6,238	6,238	6,238	6,238
<b>Annual Hours of Operation for Capacitor #2</b>	16	0	0	0	0	0	0
<b>Annual Hours of Operation for Capacitor #3</b>	7,872	41	41	41	41	41	41

Adding PV and SIS to the circuit also has a slight impact on the loading of the substation transformer, as Table 4-13. shows. However, the transformer never exceeds 89% of its rated capacity in any scenario, and is relatively lightly loaded over the course of the year. While the reduced loading from the addition of PV and SIS units might extend the life of a more heavily loaded transformer, the change in loading on the Waterman-Grantline transformer is unlikely to impact the life of the equipment.

**Table 4-13. Loading of Waterman-Grantline Substation Transformer in Each Scenario.**

	<u>Baseline</u>	<u>Low Penetration</u>			<u>High Penetration</u>		
		PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)
<b>Annual Load Factor of Substation Transformer</b>	35.4%	35.3%	35.3%	35.3%	35.2%	35.2%	35.2%
<b>Peak Loading of Substation Transformer</b>	88.9%	88.0%	88.8%	88.2%	88.8%	87.4%	87.5%

#### 4.2.6.5 *Results—Power Quality*

**Table 4-14 Total Number of 15-Minute Intervals Where One or More Nodes Had a Voltage Violation During the Year.**

<u>Baseline</u>	<u>Low Penetration</u>			<u>High Penetration</u>			
	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	
<b>Total Annual Under-Voltage Events</b>	1,338	1,281	1,278	1,276	1,271	1,245	1,250
<b>Total Annual Over-Voltage Events</b>	530	532	532	532	546	543	

Table 4-14 shows the total number of under- and over-voltage events occurring in each scenario over the course of the year. These events count each 15-minute interval where the voltage at one or more nodes in the circuit falls below 0.95 per unit, or rises above 1.05 per unit (e.g., if there are three nodes below the acceptable voltage at a given time interval, that would count as one event). The number of over-voltage events does not change significantly between cases, but the addition of PV and SIS units to the circuit does drive a reduction in the number of under-voltage events (from 3.8% to 3.6% of the 15-minute time intervals). The majority of the under-voltage events occur in the residential areas of feeders 1 and 3 (toward the end of each feeder). These events occur throughout the year, most often in the evenings when residential loading is greatest, but are fairly minor as the voltage on 1 or 2 phases of each feeder dips slightly above and below 0.95 per unit.

The addition of PV and SIS units to the circuit helps to alleviate some of the under-voltage conditions on the circuit, but the impact is limited because of the timing of the under-voltage events relative to the timing of the output from the PV and SIS units. While output from PV alone, in both the low and high penetration scenarios, does reduce the number of under-voltage events, the impact is limited to voltage issues that occur when the sun is shining. The addition of SIS units in the high penetration scenarios does further reduce the number of under-voltage events, but in this case the impact is limited by the SIS unit

dispatch algorithm. As described in section 4.2.5.2, the SIS unit use cases included in this modeling discharge the SIS batteries between the hours of 4:00 pm to 7:00 pm. As a result, the SIS units extend the output to the grid from the combined PV and SIS systems to later in the evening. This helps to address several additional under-voltage events, but does not address under-voltage events that occur later at night. In addition, there are many instances where the SIS units do help to raise the voltage from 4:00 pm to 7:00 pm, but not enough to raise the voltage magnitude above 0.95 per unit.

In instances of minor voltage issues as seen on Waterman-Grantline feeders 1 and 3, it may be possible to develop new SIS unit dispatch algorithms that would better alleviate under-voltage conditions on the circuit. For example, the SIS units could be dispatched to charge and discharge based on local circuit voltage conditions, rather than (or in addition to) the time-based use cases included in this analysis. This could create additional value from the SIS units in cases where SMUD determined that the voltage excursions on the circuit needed to be addressed by installing new voltage regulation equipment on the feeders (e.g., line regulators), as an alternate SIS unit dispatch algorithm could be used to obviate the need for purchasing other equipment.

To explore this possibility, RMI simulated a hypothetical use case wherein the ‘customer dispatch’ SIS dispatch algorithm was modified to respond to voltage conditions on the circuit. The original algorithm discharges the SIS units at a constant rate of 58% of the unit’s maximum output during the 4:00 pm to 6:00 pm period. The modified algorithm instead discharges the battery at the SIS unit’s maximum output for short durations if there are under-voltage violations occurring on the feeder within this time period.

The example ‘voltage response’ use case was tested for a portion of the year in the low penetration scenario. Figure 4-12 and Figure 4-13 show voltage conditions on March 25, 2015 starting at 4:00 pm near a residential load on Waterman-Grantline feeders 1, under the set of PV and SIS scenarios as well as with the ‘voltage response’ use case. On this day, voltage at the bus drops below 0.95 per unit at 4:30 pm and remains there until after 6:00 pm in the baseline scenario. The addition of PV raises the voltage back above 0.95 per unit for some time steps, while adding SIS units (both utility and customer dispatch scenarios) brings the voltage above 0.95 per unit for all but one-time step (4:45 pm).

SIS unit dispatch in the ‘voltage response’ scenario is the same as the customer dispatch scenario for most of the day, but at 4:45 pm the modified algorithm responds to the under-voltage condition by increasing the discharge rate of the battery. As a result of the additional SIS output, the under-voltage issue at the

bus is resolved. While further analysis and algorithm development would be required to verify the ability of SIS units to provide this service reliably over time, there is an opportunity to significantly reduce investment costs in locations with voltage regulation issues. For example, if SMUD planners felt that conditions on this feeder required installation of a line voltage regulator in 2020, and if the 34 SIS units modeled here were able to reliably eliminate the voltage issues on the feeder, the deferral value would be approximately \$83/kW-yr. of SIS capacity.

While an SIS use case to address voltage issues was not developed as part of this project, the above example illustrates the potential for residential PV and SIS to provide this service. Future research can further explore this use case by identifying distribution circuits where voltage regulation equipment is needed, and then testing the ability to use PV and SIS to defer investment.

**Figure 4-12. Example Use of ‘Voltage Response’ SIS Unit Algorithm to Address Under-Voltage Events, Showing Voltage at a Sample Node on Feeder 1.**

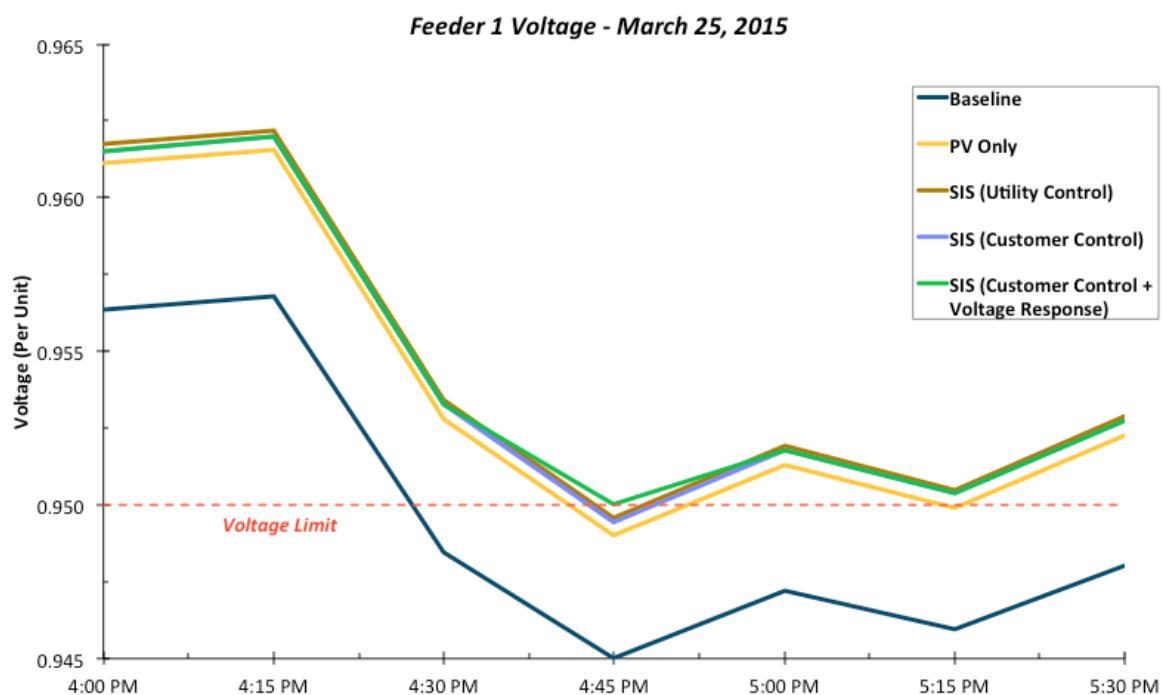
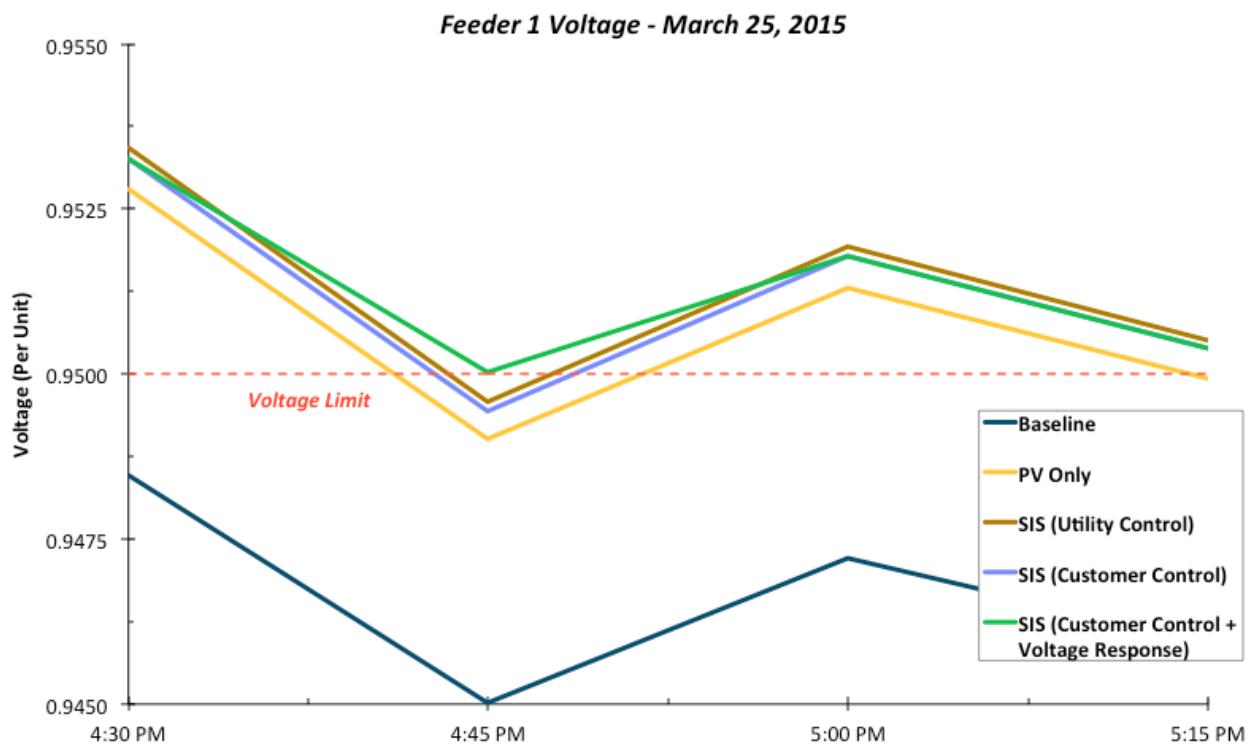


Figure 4-13. Magnified View of the Example ‘Voltage Response’ SIS Use Case.



# 5 Benefits to California Ratepayers

In order to quantify the possible benefits to California ratepayers in the SMUD territory of consumer adoption of SIS units, E3 conducted a case study using the integrated distributed energy resource modeling and analysis tool (iDER). The iDER tool simulates the optimal hourly dispatch of DERs, quantifies the various value streams delivered by DERs, and, produces the *California Standard Practice Manual* cost-effectiveness tests for demand side programs (California Public Utilities Commission, 2001). The study analyzes the economic impacts of SIS adoption on two example distribution feeders, Jackson-Sunrise and Waterman-Grantline. Economic impacts are evaluated for three possible modes of SIS control: PV only, utility dispatch, and customer dispatch. In the PV only case, we assume that no storage has been installed. In the utility or customer dispatch cases, dispatch of storage is optimized to maximize the benefits to the controlling entity. Several sensitivity scenarios are also studied.

The economic impacts quantified and the cost-effectiveness tests considered in this study are provided in section 5.1. Case study scenarios are developed in section 5.2. The methodology of the iDER analysis tool is summarized in section 5.3 with more detail provided in Appendix 8.1. We analyze the local distribution investment deferral and operational benefits of SIS adoption in section 5.4. The cost-effectiveness of SIS adoption is analyzed under the Participant Cost Test (PCT), Total Resource Cost Test (TRC), and Ratepayer Impact Measure Cost Test (RIM) perspectives in section 5.5. Several sensitivities are studied to understand the impact of various SIS capabilities and retail rates on the cost tests in section 5.6. Given the cost-effectiveness results, we analyze the maximum ratepayer neutral incentive that a utility could provide to customers purchasing SIS units in section 5.7. The major conclusions of the case study are summarized in section 5.8. All results are presented in \$/kW-yr. on the basis of rated kW output of the SIS units, which is 4.5kW nominally and 6kW when considering the larger new model.

## 5.1 Economic Impacts of Distributed Energy Resources

### 5.1.1 COSTS AND BENEFITS

This subsection briefly describes the numerous costs and benefits quantified and included in the case study. Table 5-1 provides a brief overview of the avoided costs of supplying marginal energy from the

utility's perspective. These costs are avoided if energy consumption is reduced or DERs produce energy and increased if consumption is increased or DERs consume energy, and can have time varying values. The avoided costs have a 10-yr. procedural history in evaluating the cost-effectiveness of distributed energy resources at the California Public Utility Commission (CPUC).

**Table 5-1. Utility's Avoided Cost of Energy Components.**

Component	Description
Avoided Energy Cost	Hourly wholesale value of energy
Avoided Generation Capacity Cost	The avoided cost of building new generation capacity to meet system peak loads
Avoided Ancillary Services Cost	The avoided marginal costs of providing system operations and reserves for electricity grid reliability, assumed to be 1% of energy cost
Avoided Losses	The avoided cost of increased resistive transmission and distribution losses due to an increase in end users load
Avoided Emissions	The avoided abatement cost of carbon dioxide (CO <sub>2</sub> ), nitric oxide, and nitrogen dioxide (NO <sub>x</sub> ) emissions associated with the marginal generating resource
Avoided RPS	The avoided purchases of required renewable generation at above-market prices required to meet a renewable portfolio standard
Distribution Deferral Value	The time value of money when the peak distribution network load is reduced, and an investment in distribution capacity can be deferred
Distribution Operations	Avoided mechanical wear on distribution equipment such as tap changing transformers or switching capacitors

Table 5-2 describes the costs and benefits that a utility customer faces when deciding to adopt a DER such as the SIS.

**Table 5-2. DER Adopting Customer's Costs and Benefits.**

Component	Description
Federal Tax Credits	Federal Solar Investment Tax Credit

SGIP Incentive	California Self Generation Incentive Program payment from a utility company to a distributed generation adopting customer
Utility Bill Savings	Customer's retail electricity bill savings during the useful life of a DER
Ancillary Services Revenue	Revenue earned from DER participation in CAISO ancillary services markets
UPS Reliability Value	Reliability value that an SIS adopting customer gains from using the SIS as an uninterruptable power supply (UPS) during a blackout
Total Battery Cost	Purchase cost of the SIS battery energy storage system
Total PV Cost	Purchase cost of rooftop PV associated with the SIS unit.

### 5.1.2 CPUC STANDARD PRACTICE MANUAL COST TESTS

In this subsection, we present a brief overview of the CPUC cost-effectiveness tests for demand side programs and how they were applied in this case study. The three cost tests implemented for this study are the Participant Cost Test (PCT), Total Resource Cost Test (TRC), and Ratepayer Impact Measure Cost Test (RIM). Table 5-3 shows how the various economic impacts are viewed as costs or benefits from different cost test perspectives. A green cell with a plus sign indicates that the component is considered as a benefit, while a red cell with a minus sign indicates that the component is a cost.

**Table 5-3. Costs and Benefits from Each Cost Test Perspective.**

Benefit and Cost Component	TRC	RIM	PCT
Federal Tax Credits	+		+
SGIP Incentive		-	+
Utility Bill Savings		-	+
Ancillary Services Revenue	+		+
UPS Reliability Value	+		+
Total Battery Cost	-		-
Total PV Cost	-		-
Distribution Deferral Value	+	+	
Avoided Energy Cost	+	+	
Avoided Generation Capacity Cost	+	+	
Avoided Emissions Cost	+	+	
Avoided Losses Cost	+	+	
Avoided Ancillary Services Cost	+	+	
Avoided RPS Cost	+	+	
Avoided Capacitor Operation Costs	+	+	

#### 5.1.2.1 *Participant Cost Test (PCT)*

The PCT is designed to assess if a demand side program is cost effective from the perspective of the end consumer who chooses to participate in a program or install a DER or energy efficiency measure. The costs to the customer are the purchase cost of the SIS system, which is composed of PV system and battery energy storage system costs. We assume that SIS units are purchased by an upfront cash payment. The benefits to the customer from adopting an SIS are the Federal Investment Tax Credit (ITC) for solar power systems, the California Self-Generation Incentive Program (SGIP), retail electricity bill savings, and reliability value from the SIS providing an uninterrupted power supply. In the sensitivity where the SIS can sell ancillary services in the CAISO markets, ancillary service revenue is also considered as a participant benefit.

### 5.1.2.2 **Total Resource Cost Test (TRC)**

The TRC assesses the monetized costs and benefits to California as a whole. The costs are the purchase cost of the SIS system and associated PV. The benefits to California are the avoided costs of supplying energy and the ITC. Costs of supplying energy are avoided when load is reduced or shifted from times when resources are expensive or limited to times when they are less expensive. The avoided costs of supplying energy include reduced renewable portfolio standard (RPS) procurement obligation, avoided ancillary services purchases, avoided resistive transmission and distribution losses, avoided emissions compliance costs, avoided generation capacity costs, avoided energy purchase or generation costs, and distribution capacity upgrade deferral savings. In our case study, we also include avoided distribution capacitor operation costs that were calculated for the Waterman-Grantline feeders.

### 5.1.2.3 **Ratepayer Impact Measure Test (RIM)**

The RIM quantifies the effect of a program on the non-participant ratepayers through its effect on the average per kWh charge needed to recover the utility's sunk costs. The costs of the RIM are the SGIP incentive payment to SIS adopters as well as the bill savings of SIS adopters. These costs represent a payment from non-participant ratepayers to program participants, which in this case are SIS adopting customers. Customers are eligible for the SGIP in SMUD's service territory if they are PG&E gas customers. In this case, the SGIP incentive is actually paid to the customer by PG&E, but in order to generalize our analysis to California IOUs, we include the SGIP as a cost in the RIM test. The benefits of the RIM include all of the avoided costs of the TRC.

## 5.2 Case Study Design

This section describes the scenarios analyzed in this case study. We describe the data used as input to the model and the various sensitivities conducted. The study focuses on the economics of SIS units on two potential investment plans in SMUD's territory (Waterman – Grant line and Jackson Sunrise). Simulating SIS units on two different distribution network locations allows us to understand the importance of location to the value that SIS units can create. Other sensitivity cases have been investigated to test the value of SIS units in different possible situations. The period of the study is from 2016 to 2030, assuming installation happens in 2016 and the battery last its life time (15 years). We have used the best data sources available for estimating future costs and benefits, but electricity markets and prices dynamics can

change dramatically over 15 years and are highly uncertain. The main results of the case study are local distribution impacts, cost-effectiveness tests, and determining the maximum ratepayer neutral incentives for SIS adoption in the scenarios considered.

### 5.2.1 SCENARIOS STUDIED

In the base case and on both distribution networks, we model SIS adoption by 34 households. These homes are billed according to SMUD's 2015 net energy metering TOU tariff R-TOU. We also model additional distributed PV generation, not associated with SIS adopting homes, as being added to the distribution network according to SMUD's base PV adoption forecast. We investigated 3 possible control scenarios for the 34 SIS adopting homes: customer dispatch, utility dispatch, and PV only. In the customer dispatch scenario, the SIS is dispatched to lower customer utility bills while charging only from their rooftop PV. In the utility dispatch scenario, the SIS is dispatched to minimize system costs and for distribution deferral using knowledge of hourly system avoided costs, the total distribution network load, and the available distribution network capacity. The utility dispatch scenario does not limit charging to be from PV only. In the PV only scenario, it is assumed that consumers do not install SIS units, but instead have only installed rooftop solar PV.

The results were also analyzed under the following sensitivities:

- + **High DER Adoption:** This sensitivity examines how the value of SIS adoption changes when more customers adopt SIS units. On Jackson-Sunrise, we assume 60 customers with SIS units and on Waterman-Grantline, we assume 64 customers with SIS units.
- + **Larger SIS Units:** The impact of a larger, new design for SIS units described in Table 5-4 is modeled in this sensitivity.
- + **Offering Ancillary Services:** This sensitivity explores the possible additional revenues that SIS units could earn if they are able to offer ancillary services to the CAISO market.
- + **TOU + CPP Retail Tariff:** In this sensitivity, we assume that SIS adopting customers are on SMUD's experimental TOU+CPP tariff that was implemented in the summer of 2015. 12 peak days are chosen based on highest hourly avoided costs of energy.
- + **2016 TOU Retail Tariff:** SIS adopting customers are billed according to SMUD's revised 2016 TOU tariff.

- + **PG&E TOU Tariff:** In order to broaden the applicability of this study to other California utilities, we analyze the economics of SIS customers that are billed according to PG&E's E-TOU retail tariff.
- + **PG&E Demand Charge Tariff:** Customers are billed according to PG&E's A-10 tariff, which includes a \$/kW monthly demand charge based on the customers maximum 15-minute averaged net demand. The other tariffs considered do not have demand charges.
- + **High Capacity Resource Value:** WECC's Transmission Expansion Planning Policy Committee (TEPPC) calculates the cost of new entry (CONE) for an aeroderivative combustion turbine as \$250/ kW-yr. The economics of SIS units when generation capacity is priced according to WECC's CONE value are investigated in this sensitivity.
- + **Reliability Value:** Using SMUD's SAIDI and SAIFI data and LBNL's estimated reliability prices for different customer classes and durations, we calculate the reliability value that SIS battery storage could provide to customers.

## 5.2.2 INPUT DATA

### SIS Model Parameters

Table 5-4 shows the sizing and cost values used for this study. Solar PV costs are taken from E3's NEM Successor Public Tool (Energy and Environmental Economics, 2015) and battery costs were provided by Sunverge. The 2500 R SIS model is used in the base case of this study and represents the units installed in the 2500 R Street demonstration. The New SIS model represents a potential future Sunverge design. SIS Battery costs do not include installation, permitting, or initialization costs. In all cases examined in this study, we assumed that battery state of charge must be maintained between 10% and 95%.

**Table 5-4. SIS Equipment Cost and Sizing.**

SIS Model	Solar PV Cost (\$)	Battery Cost (\$)	Total SIS Cost (\$)	Solar Size (kW)	Max Battery Power (kW)	Max Battery Energy (kWh)
2500 R	8,899	11,000	19,899	2.25	4.5	11.64
New	17,798	15,000	32,798	2.25	6	19.64

### Hourly Prices for Optimal Dispatch

With the iDER model, the avoided costs of supplying energy need to be determined for every hour of the year to be used as an hourly price signal in the dispatch model. The hourly granularity is obtained by either

shaping forecasts of the average value of components with historical prices or inflating historical prices; Table 5-5 summarizes the methodology applied to each component to develop this level of granularity.

**Table 5-5. Source and Methodology Applied to Develop Hourly Component Values.**

Avoided Cost Component	Basis of Hourly Shape	Basis of Annual Forecast	Notes
<b>Distribution Deferral Value</b>	NA	NA	Detail investment plan provided by SMUD,
<b>Avoided System Capacity Costs</b>	Hourly allocation factors calculated by PCAF method based on system net load	SMUD Resource Adequacy Contract Price Forecast	More about PCAF method in section Appendix 8.3
<b>Avoided System Energy Costs</b>	E3 Latest Avoided Cost Model for 2016 (\$/kWh)	SMUD Resource Adequacy Contract Price Forecast	
<b>Other System Avoided Costs</b>	E3 Latest Avoided Cost Model for 2016 (\$/kWh)	Inflation Rate (1.5 %)	
<b>Avoided Distribution Operation Costs*</b>	NA	Inflation Rate (1.5 %)	GridEdge model
<b>Customer Bill Savings</b>	Base Case: 2015 SMUD Smart Pricing Options (2015 TOU) (\$/kWh)	Inflation Rate (1.5 %)	
<b>Regulation Up Services Revenue**</b>	2015 CAISO Hourly Day-Ahead Market Price (\$/kWh)	Inflation Rate (1.5 %)	
<b>Regulation Down Services Revenue**</b>	2015 CAISO Hourly Day-Ahead Market Price (\$/kWh)	Inflation Rate (1.5 %)	
<b>Spinning Reserve Services Revenue**</b>	2015 CAISO Hourly Day-Ahead Market Price (\$/kWh)	Inflation Rate (1.5 %)	
<b>Non-Spinning Reserve Services Revenue**</b>	2015 CAISO Hourly Day-Ahead Market Price (\$/kWh)	Inflation Rate (1.5 %)	

\*Benefits that are not included in optimal dispatch price signal

\*\* Benefits that are not included in base case

Avoided distribution operation costs are calculated based on operation results from RMI's GridEdge model and are not included in the optimization price signal for dispatching. Ancillary services (AS) markets are not open to BTM storage in our base case assumptions, but a sensitivity analysis has been done to estimate SIS units revenue from providing AS.

## 5.3 Integrated Distributed Energy Resource Model (iDER)

As a part of this project, E3 has developed the Integrated Distributed Energy Resource Model (iDER). iDER is an analysis tool that simulates the optimal operation of DER technologies and evaluates their economic impact from multiple perspectives.

iDER consists of the following three modules:

- + **Optimal DER Dispatch:** This module uses mathematical programming to optimize the hourly dispatch of the SIS, maximizing the benefits to the end customer or utility.
- + **Economic Impact Quantification:** This module quantifies the various costs and benefits incurred as a result of purchasing the DER and operating it according to the optimal DER dispatch.
- + **Cost-Effectiveness Tests:** This module produces the CPUC Standard Practice Manual cost effectiveness tests for demand side programs.

The methodology of each module will be discussed in detail in the remainder of the section. First we present the optimization problem formulation of the Optimal DER Dispatch module. Next we describe the calculation of different economic impacts, including system level avoided costs, distribution deferral value, and distribution operation cost savings. Finally, we review the cost effectiveness tests performed for this study.

### 5.3.1 OPTMIZATION MODEL FOR SIS STORAGE DISPATCH

The hourly battery charging and discharging profile used in economic calculations is determined by an optimization model, which dispatches the battery to maximize the benefits to the controlling entity. All households and SIS units are modeled as a single aggregate customer. The model assumes that the battery controller has perfect foresight for important optimization inputs such as system and distribution system load, PV generation, energy avoided costs, and AS market prices. Thus the benefits shown in this analysis are the maximum benefits possible under ideal conditions.

The optimization model dispatches the SIS's battery from either the customers' or utility's perspective. When batteries are dispatched from customers' perspectives, the behavior of the batteries is determined by the retail electricity rate that the customer is facing and the amount of power generated by the SIS's PV system. Under customer dispatch, charging of the SIS's battery is restricted to be from the SIS's PV

system. Customers are assumed to be on a retail rate with symmetric net energy metering (NEM) where the customer's bill is credited for exports to the electric grid at the same rate charged for imports from the electric grid. The batteries will generally charge when retail rates are low, and discharge when rates are high.

When dispatched from the utility's perspective, a slightly more complicated optimization model is used. The primary objective of the optimization model is to reduce the net distribution feeder load to be below the threshold which would trigger an upgrade. This objective allows the SIS to create distribution upgrade deferral value. The secondary objective of the optimization model is to maximize the avoided costs of supplied energy by arbitraging an hourly time series of avoided cost values. The hourly avoided costs of supplying energy are defined in section 5.1.1. The mathematical formulation of the optimization problems solved under customer or utility dispatch is given in Appendix 8.1.

### 5.3.1.1 *Ancillary Services Sensitivity*

Under base case assumptions, the CAISO AS market is not open to behind the meter storage systems. In order to estimate the AS revenue provided by batteries, we conducted a sensitivity case where battery dispatch can be co-optimized to maximize energy price arbitrage and ancillary service revenues. We model participation in four ancillary service (AS) markets: regulation up and down, spinning and non-spinning services. Batteries are paid once they submit bids for providing AS services, but it is hard to predict whether the bid is called by the operator and requires energy from batteries. In the model, we calculated the expected percentage of AS bid being called in historical CAISO AS market, and use this as an estimate. The analysis assumes that 15% of bids are called for regulation up and down service, and none of the bids for spinning and non-spinning reserve being called. The hourly battery charging and discharging profile used in economic calculations is determined by an optimization model, which dispatches the battery to maximize the benefits to the controlling entity. All households and SIS units are modeled as a single aggregate customer. The model assumes that the battery controller has perfect foresight for important optimization inputs such as system and distribution system load, PV generation, energy avoided costs, and AS market prices. Thus the benefits shown in this analysis are the maximum benefits possible under ideal conditions.

### 5.3.2 QUANTIFYING DISTRIBUTION SYSTEM DEFERRAL VALUE

The largest potential local benefit of installing DERs is from deferring a distribution upgrade from the original installation year to a year farther in the future. Many distribution upgrades are driven by load growth. When the load exceeds the carrying capacity of the local distribution network, an upgrade must be made. DERs are able to reduce peak loads on the distribution network and delay the upgrade. The amount of DER provided load reduction that can be relied on for planning purposes is known as the reliable load reduction. If the reliable peak load reduction from DERs is great enough to delay a distribution network upgrade, then the deferral value created by the DERs can be calculated by the present worth method. The rest of the section will cover criteria for choosing an investment plan, estimating the reliable peak load reduction, and estimating the deferral value by the present worth method.

#### 5.3.2.1 *Investment Plan*

The locational avoided cost of distribution investment calculation requires the identification of potentially deferrable projects in distribution investment plans. Load and DER forecasts for the investment plan should include all areas that have an impact on the potential investment. For example, if load on feeder A and feeder B both impact a transformer upgrade plan, then the load and DER forecast used in a deferral analysis should include the forecasts for both feeders.

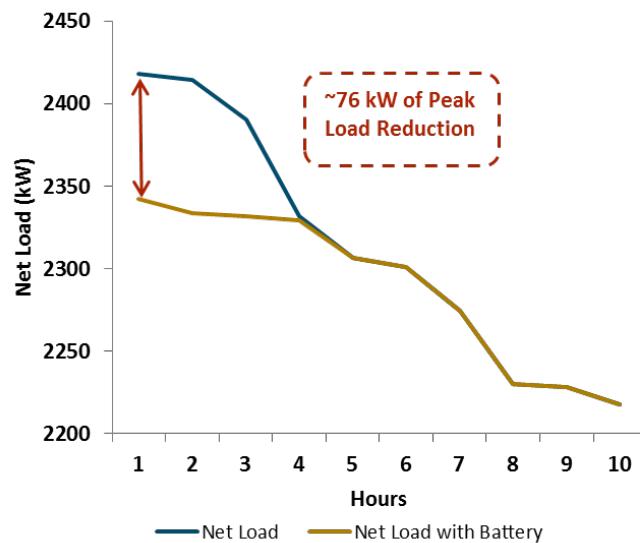
The deferrable capital investment considered should include only works or materials that could be deferred through the reduction in peak demand in the area. Examples of costs that would not be included are sunk costs, and land costs that the utility will incur even if DER might be able to defer the project by a few years. There could still be some costs when deferring projects, for example, the renting of storage units for raw material, and deferral program planning costs. This study doesn't include costs related to deferral to keep the analysis simple.

#### 5.3.2.2 *Determination of Reliable Load Reduction*

The reliable load reduction by DERs varies by technologies and is dependent on 1) the control of DER measures during peak period 2) the overlap of DER output with peak period and the 3) for renewable DERs, the uncertainty of the output. The following section focuses on the method for determining the reliable load reduction for battery and DG PV.

- A battery is a reliable DER resource, thus the reliable load reduction by a battery is simply calculated by the difference between network peak load with and without the battery. Figure 5-1 shows the highest 10 load hours with and without a battery. The difference between two highest load points is the peak load reduction of the battery. Batteries are dispatchable by either utilities or customers, and utilities have good predictions of distribution peak load day. As a result, a battery can be adequately charged for the peak load day by informing either the customer's or utility's battery operator ahead of time.

**Figure 5-1. Reliable Peak Load Reduction by Battery Storage**



- DG PV needs to be derated to account for two factors 1) the uncertainty of future PV output and 2) the coincidence between PV shape and peak load period.
  - A dependable output shape is determined to derate PV for the uncertainties of PV output. First, we calculate the distribution of PV output in each hour and season. From these distributions we take the percentile corresponding to the planning rule determined by the model user. In this study, 95% reliability is chosen, the model takes the 5th percentile of each hourly and seasonal distribution. The result is a level of output from PV that in each hour of the year, PV would be expected to produce at or higher than for 95% of the time. This is the dependable PV measure output.

- The second step is derating PV for the coincidence between PV dependable shape and peak load period: PCAF values identify distribution system peak load periods, and by multiplying hourly dependable PV output shape with the hourly PCAF values, we can have the reliable load reduction by PV.

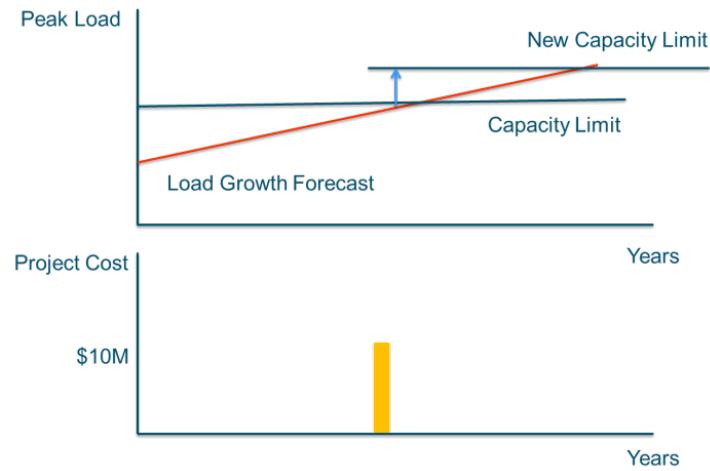
After the reliable peak load reduction is determined for each technology, deferral value can be calculated based on the present worth method. The contributions of each technology toward deferral value are allocated based on the reliable peak load reduction at original installation year.

#### 5.3.2.3 **Present Worth Method**

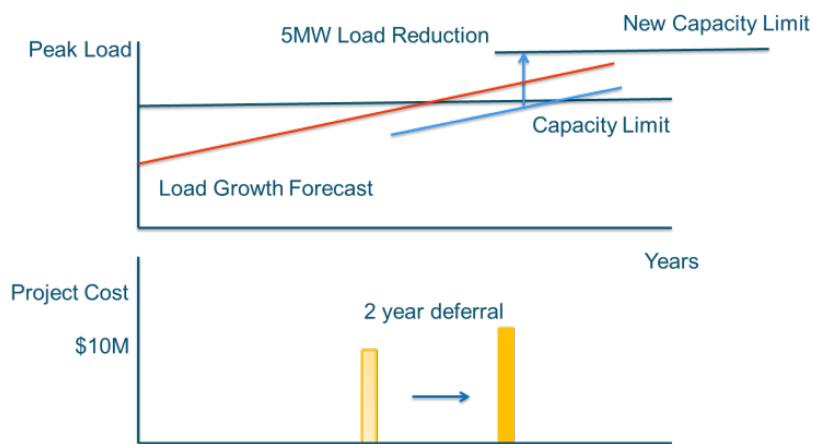
Economically meaningful estimates of distribution capacity costs require a method that captures the area-and time-specific nature of lumpy distribution investments. One such method is the Present Worth (PW) method. The essence of the PW method is that the value of deferring a local expansion project for a specific period of time reduces the present value of the project cost due to the time value of money. A one-yr. deferral value equals the difference between the present value of the expansion plan and the present value of the same plan deferred by one year, adjusted for inflation and technological progress.

Figure 5-2 shows a network T&D investment of \$10M. The project is needed to prevent the load growth from exceeding the area load carrying capability. In Figure 5-3, the load growth is reduced from the red line to the blue line, which allows the investment to be deferred by 2 years. The deferral results in a savings of about \$1M if inflation is 2% and the utility WACC is 7.5% ( $\$10M - \$10M * (1.02/1.075)^2$ ). If we further assume that 5MW was needed to achieve that deferral, the avoided cost per kW is \$200/kW ( $\$1M/5MW$ )

**Figure 5-2. Investment in Distribution Project Due to Load Growth**



**Figure 5-3. Project Deferral of Network Investment**



### 5.3.3 AVOIDED DISTRIBUTION OPERATING COSTS

Additional DERs might have detrimental or beneficial impacts on distribution system operation. Potential impacts include impacts on energy losses, changes of equipment lifetime, power quality, and wear-and-tear of mechanically switched equipment (i.e. transformer load tap changers, line voltage regulator, and switched capacitor banks). RMI simulated the operation of distribution system and measured the changes of operating parameters under multiple scenarios. More detailed description of simulation methodology and results are in section 4.2.5 and 4.2.6. The most significant impact identified in the simulation is the change of capacitor lifetime, as a result, capacitor replacement savings for Waterman Grant Line

substation are calculated and included in cost test analysis. The formulas used to calculate capacitor operational savings are provided in Appendix 8.2.

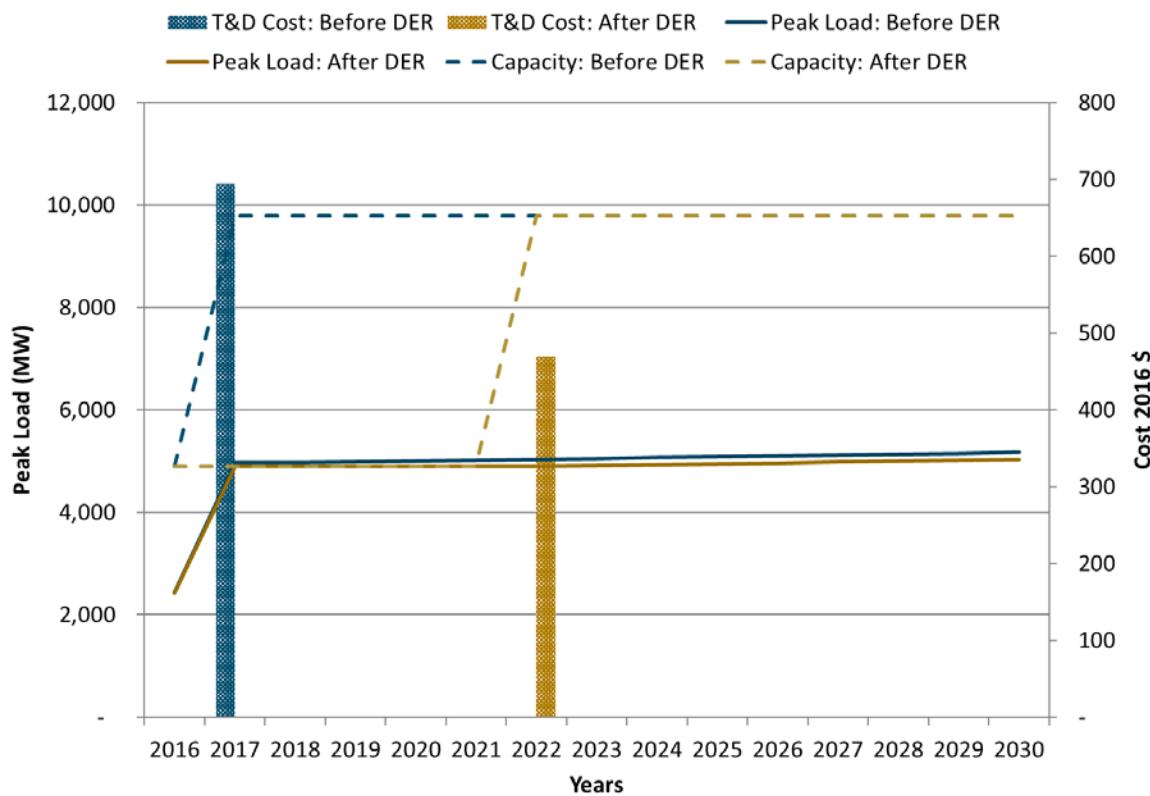
## 5.4 Local Distribution Benefits

In this section, we present results from our base cases regarding the local distribution upgrade deferral benefits and reduced distribution system operation costs from SIS adoption. For each scenario and distribution feeder, we estimate the number of years an upgrade can be deferred. The value of the deferral is due to the time value of money. Future upgrade costs are discounted using SMUD's weighted average cost of capital (WACC), making an upgrade less expensive the further in the future that the upgrade occurs. The results below also show how the number of years an upgrade can be deferred and the deferral value depend on the number of SIS units installed. We also analyze the avoided distribution operation costs from capacitor wear using the methodology described in section 5.3.3.

### 5.4.1 JACKSON-SUNRISE

Figure 5-4 illustrates the timing and value of distribution upgrades on the Jackson-Sunrise feeders when SIS units are under utility dispatch. In 2017, a single large load is added to the distribution network, and then load grows gradually. Dashed lines show the feeder's peak load capacity (MW) over time when there are no DERs installed in blue and when DERs have been installed in gold. The total feeder peak load (MW) is shown with solid lines. The blue solid line gives the peak load in the absence of DERs while the gold solid line gives the peak load in the presence of DERs. With no DERs installed, the feeder must be upgraded in 2017, resulting in a jump in the blue dashed line. However, when Solar PV and SIS units are installed, an upgrade does not occur until 2022. The cost of the upgrade that occurs in 2022 is much smaller than that in 2017 because of 5 years of discounting.

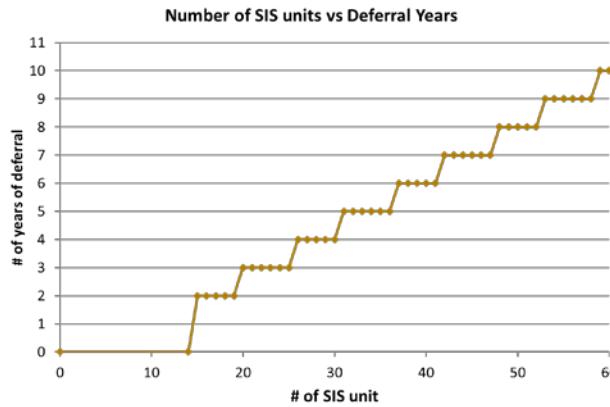
**Figure 5-4. Distribution Upgrade Deferral on the Jackson-Sunrise feeders.**



For the Jackson-Sunrise feeders, 5 years of deferral are achieved in the base DER adoption scenario when the utility dispatches the SIS units, giving a deferral value of \$148/(kW-yr.). When distribution upgrades are deferred, the value of the deferral is allocated to both the SIS units and the PV on the distribution network that is not associated with an SIS unit. The allocation is done according to the share of energy supplied during times when load would otherwise exceed the upgrade threshold. The distribution upgrade is not deferred under customer dispatch or PV only control cases.

The number of years of deferral is sensitive to the amount of DERs installed on the distribution network and the. Figures 10 and 11 show how years of deferral and deferral value change with the number of SIS units installed under the base forecast for PV adoption and with utility dispatch of SIS units. Figure 5-5 shows that at least 15 SIS units would need to be installed to defer upgrades for one year. It is assumed that deferral can only be done for whole years, giving the plots in Figures 10 and 11 stepwise increases as the number of SIS units increases.

**Figure 5-5. Number of Years of Deferral as a Function of the Number of SIS Units on Jackson-Sunrise**



**Figure 5-6. Deferral Value as a Function of the Number of SIS Units on Jackson-Sunrise**

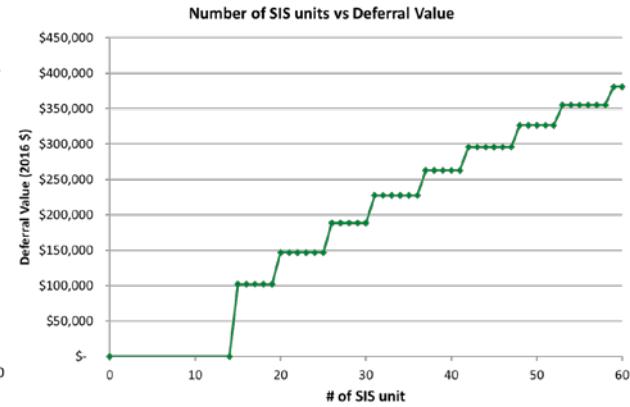
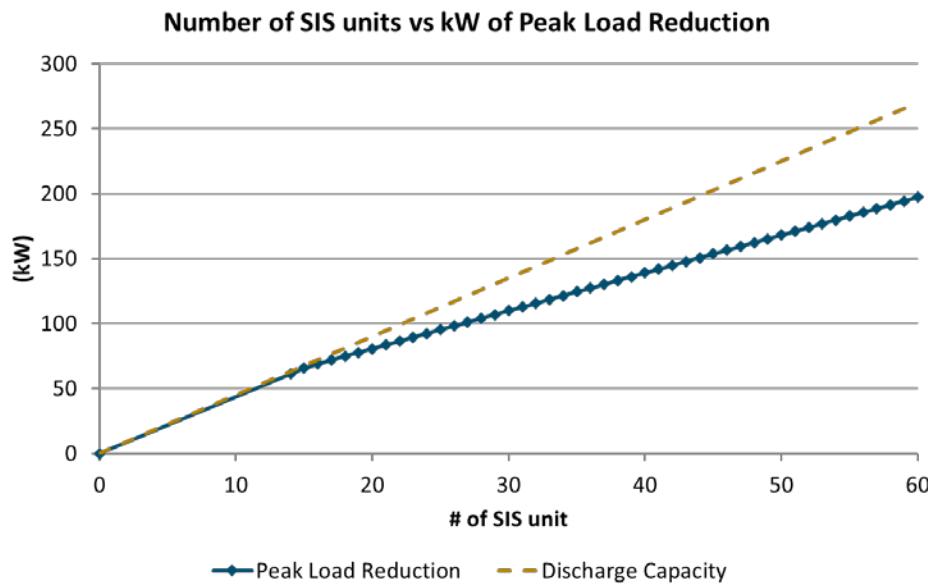


Figure 5-7 shows the reduction in distribution system peak load that is achieved as a function of the number of SIS units installed. The peak discharging capacity of the SIS units is shown by the dashed gold line while the actual reduction in peak load is shown by the blue solid line. The peak load is reduced by less than the installed discharging capacity because the amount of energy that each SIS unit can shift to off-peak hours is also limited.

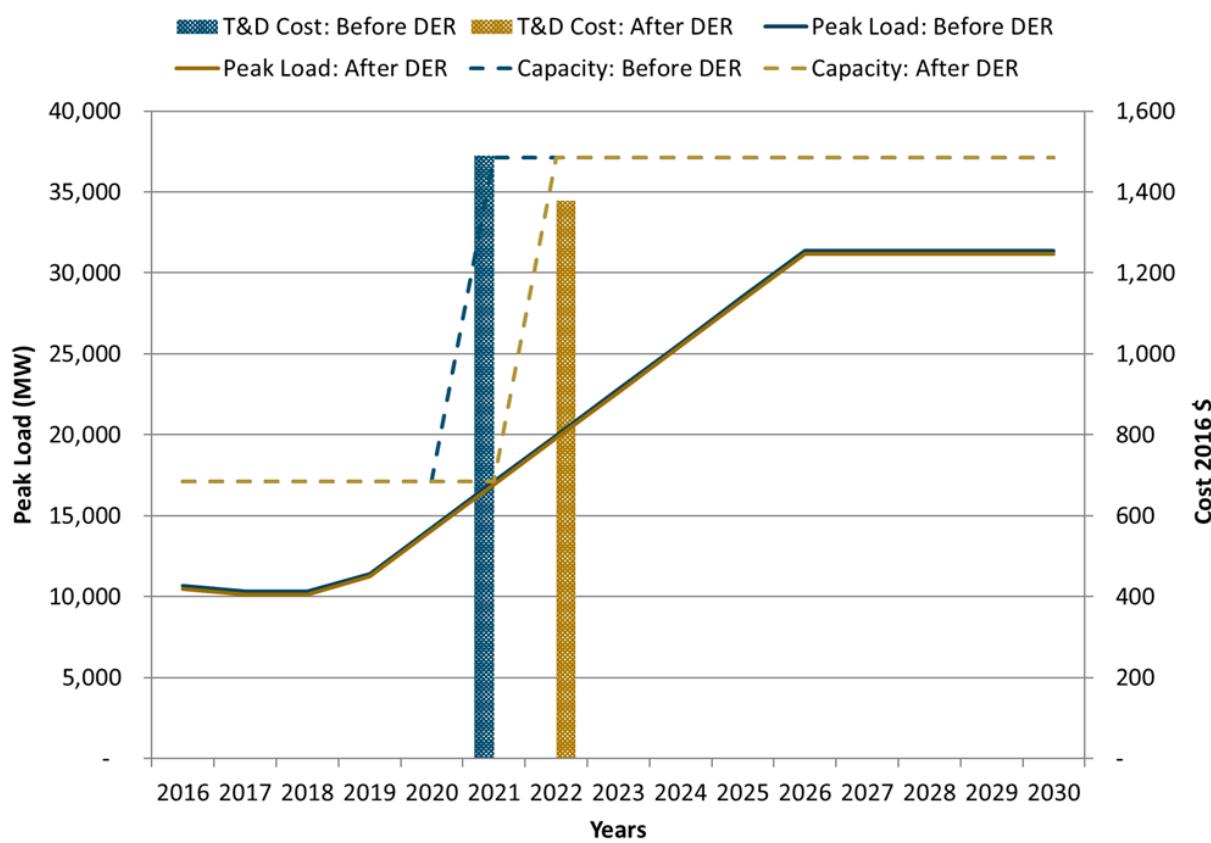
**Figure 5-7. Distribution Peak Load Reduction as a Function of Number of SIS Units.**



## 5.4.2 WATERMAN-GANTLINE

Figure 5-8 illustrates the timing and value of distribution upgrades on the Waterman-Grantline feeders when SIS units are under utility dispatch. From 2017 to 2025, the load on the Waterman-Grantline feeders is expected to grow very quickly from 10,000 MW to more than 30,000 MW. With no DERs installed, the forecast peak load in 2020 would just exceed the upgrade threshold, and so a capacity upgrade occurs in 2020. The addition of any PV to the system, regardless of whether or not there is storage installed or how the storage is controlled, yields one year of investment deferral. Because the load growth is fast, it would require more than 1000 SIS units to achieve a second year of deferral. The deferral value allocated to the SIS units is shown in Table 5-6 and varies with the SIS control choice due to the different allocation of the same deferral value to the SIS units and PV.

**Figure 5-8. Distribution Deferral on the Waterman-Grantline feeders.**



**Table 5-6. Waterman-Grantline Deferral Value by SIS Control Choice (\$/kW-yr.).**

PV Only	Utility dispatch	Customer dispatch (TOU)
18	85	45

### 5.4.3 WATERMAN-GANTLINE AVOIDED DISTRIBUTION OPERATION COST

Table 5-7 shows the levelized capacitor replacement savings for six cases when using high and low capacitor costs assumptions. High replacement costs case assumes \$25/kVAR for replacement and low case assumes \$20/kVAR. Average capacitor replacement savings are used in the cost tests.

**Table 5-7. Levelized Distribution Capacitor Replacement Savings (\$/kW-yr.).**

Capacitor Replacement Cost	Base DER Case			High DER Case		
	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)	PV Only	SIS (Utility dispatch)	SIS (Customer dispatch)
High	10.40	10.40	10.40	5.44	5.44	5.44
Low	2.27	2.27	2.27	1.19	1.19	1.19
Average	6.34	6.34	6.34	3.31	3.31	3.31

## 5.5 Cost Benefit Analysis

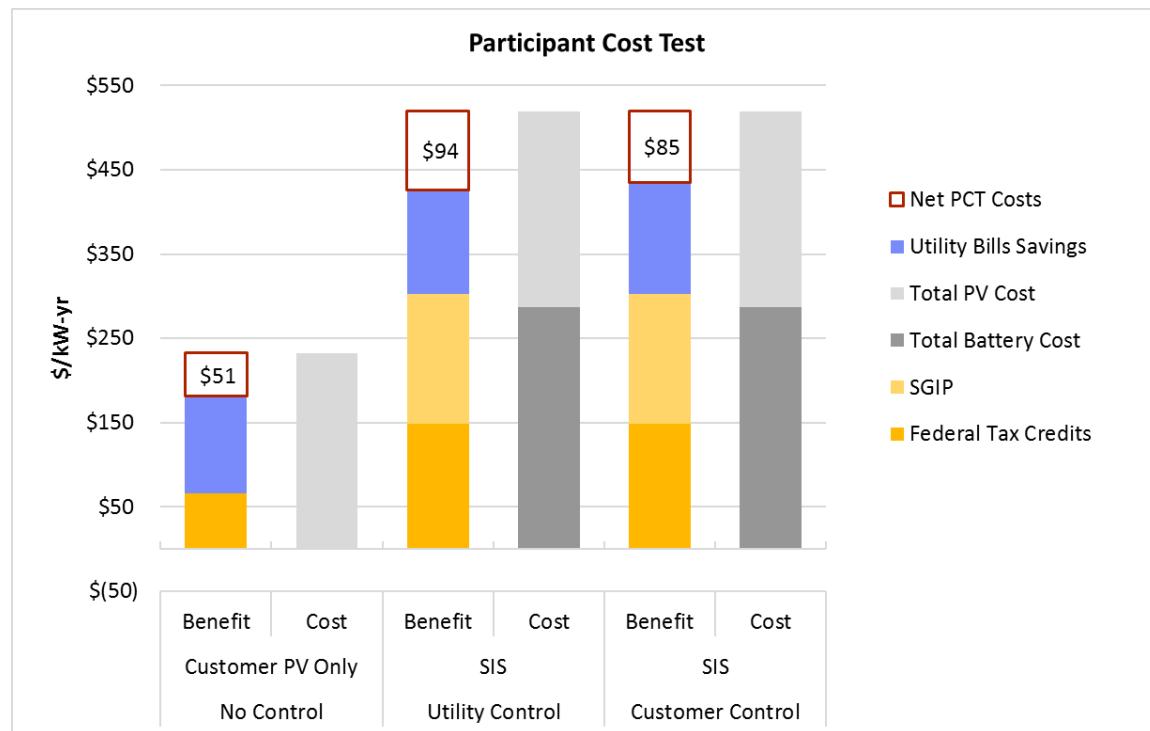
Three of the CPUC Standard Practice Manual cost tests for demand side resources were used to analyze the costs and benefits of SIS adoption from multiple perspectives. Using the results of the iDER model, we present the Participant Cost Test (PCT), Total Resource Cost Test (TRC), and Ratepayer Impact Measure Cost Test (RIM) for SIS adoption on both example feeders in the subsections below.

### 5.5.1 PARTICIPANT COST TEST (PCT)

Figure 5-9 shows the PCT for customers in this case study under the three SIS control choices. The PCT shows that purchasing SIS units would not be cost effective for SMUD customers for any of the SIS control

choices as indicated by the net PCT cost in the red boxes. In the PV only SIS control case, we assume that customers simply purchased PV panels without an SIS storage unit. The PCT results are nearly the same for customers on both feeders.

**Figure 5-9. PCT for Customer SIS Adoption on the Jackson-Sunrise feeders.**



### 5.5.2 TOTAL RESOURCE COST TEST (TRC)

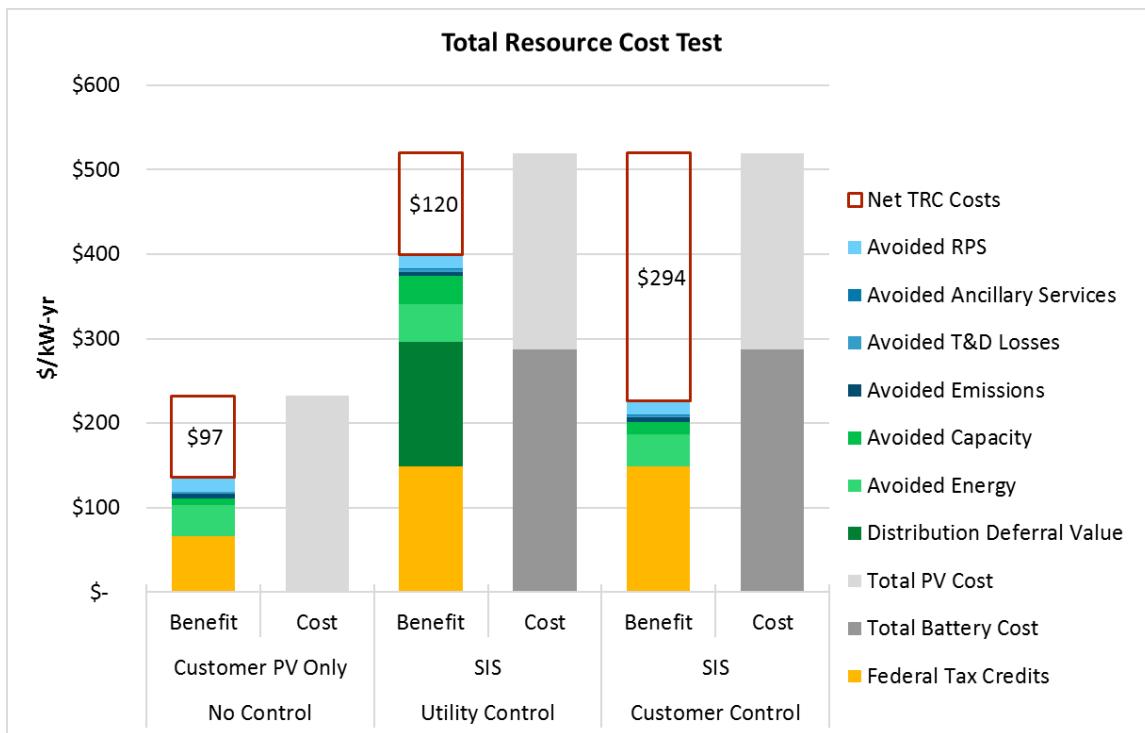
For the Waterman-Grantline feeders, we were also able to include distribution capacitor operation savings based on the analysis by RMI shown in sections 4.2.5 and 4.2.6. Because distribution deferral savings will vary based on location, we calculate the TRC separately for the two example feeders.

For the Jackson-Sunrise feeders, the TRC results show that SIS adoption results in a net cost to California for all of the SIS control cases as shown in Figure 5-10. The utility dispatch case has the lowest net cost due to larger avoided generation capacity cost and distribution deferral savings. For the Waterman-Grantline feeders, the TRC results show that SIS adoption results in a net cost to California for all of the SIS control cases as shown in Figure 5-11. The utility dispatch case has the lowest net cost due to larger avoided generation capacity cost and distribution deferral savings. The distribution deferral savings varies

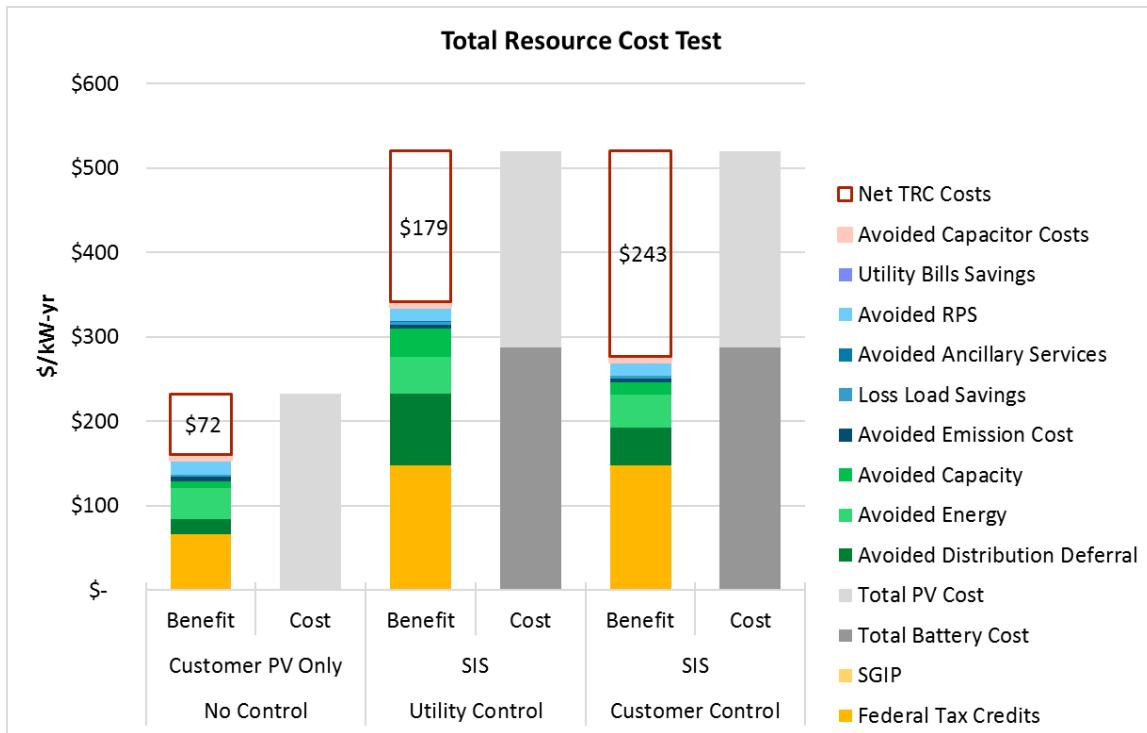
between SIS control cases on the Waterman-Grantline feeders because of the way deferral value is allocated between the SIS units and other distribution network PV.

The results of the TRC also indicate that utility dispatch is able to maximize the avoided costs of supplying energy to the customers. The avoided cost component prices and shapes used in this study were not provided by SMUD, therefore SMUD's TOU retail tariff was not designed to reflect the time varying avoided cost of supplying energy used in this study. In reality, we would expect a closer match between the avoided costs of the customer dispatch and utility dispatch cases.

**Figure 5-10. TRC for SIS Adoption on the Jackson-Sunrise feeders**



**Figure 5-11. TRC for SIS Adoption on the Waterman-Grantline feeders.**



### 5.5.3 RATEPAYER IMPACT MEASURE (RIM) TEST

Figure 5-12 shows the RIM test cost and benefit to non-participant ratepayers from SIS adoption under the different SIS control cases for the Jackson-Sunrise feeders. The addition of SIS units or PV results in a net cost to non-participant ratepayers. The cost to non-participant ratepayers is smallest when the utility dispatches the SIS units.

**Figure 5-12. RIM for SIS Adoption on the Jackson-Sunrise feeders.**

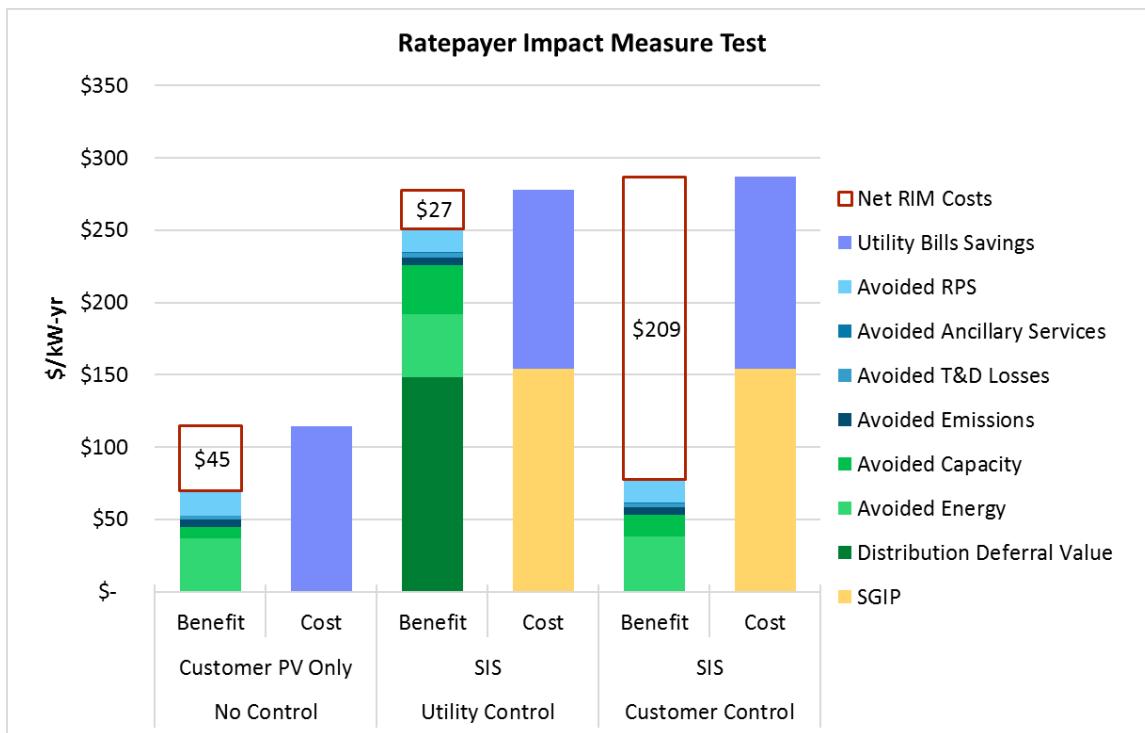
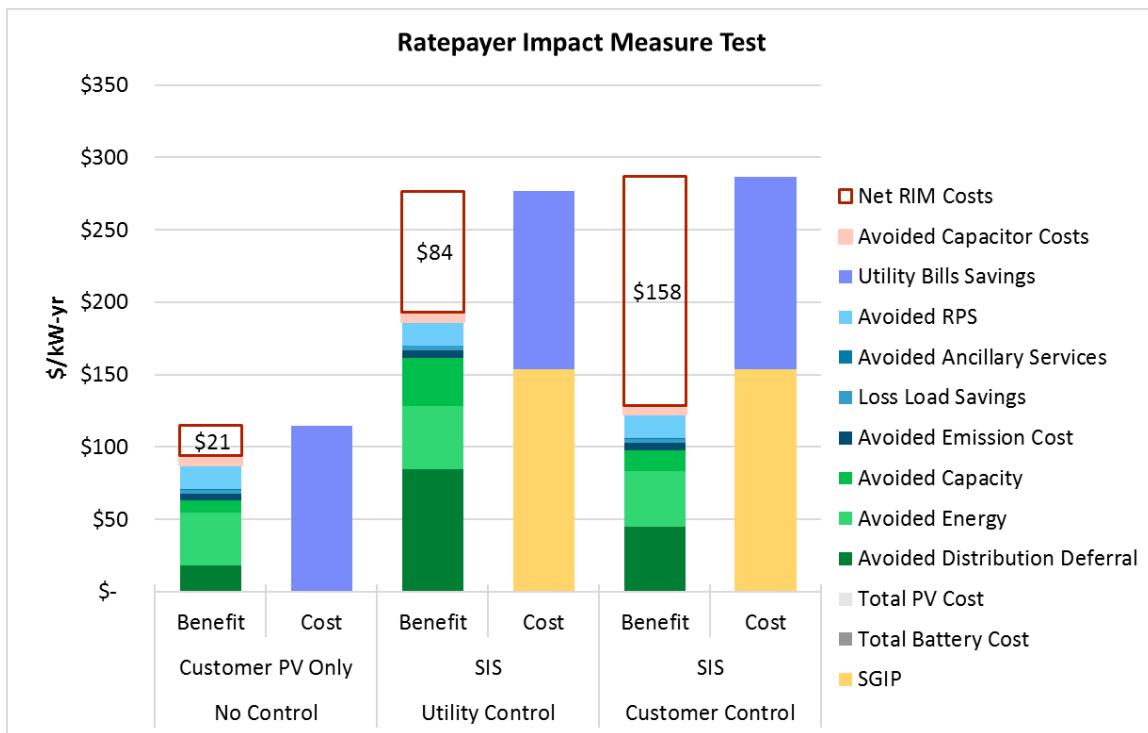


Figure 5-13 shows the RIM test cost and benefit to non-participant ratepayers from SIS adoption under the different SIS control cases for the Waterman-Grantline feeders. The addition of SIS units or PV results in a net cost to non-participant ratepayers. The cost to non-participant ratepayers is smallest when the utility dispatches the SIS units.

**Figure 5-13. RIM for SIS Adoption on the Waterman-Grantline feeders.**



## 5.6 Sensitivity Analysis

### 5.6.1 HIGH DER ADOPTION

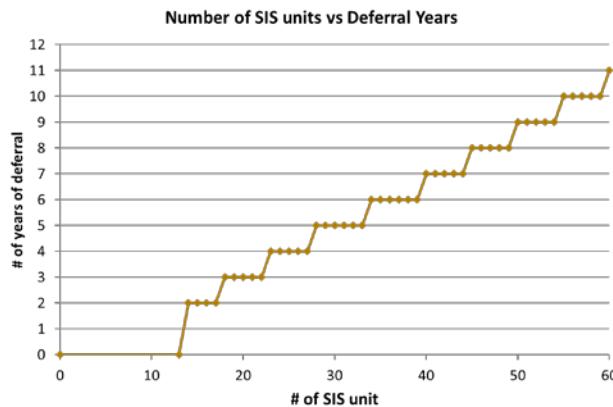
In the high DER adoption case, we consider the impact of greater SIS and PV adoption than that considered in the base case. In the base case, we assumed that 34 SIS are installed units on each feeder. In the High DER adoption sensitivity, we assume that 60 consumers on the Jackson-Sunrise feeders and 65 consumers on the Waterman-Grantline feeders adopt SIS units. The other distribution connected PV capacity is also assumed to be larger than in the base DER adoption case in line with SMUD's high PV adoption forecast.

#### 5.6.1.1 *Jackson-Sunrise*

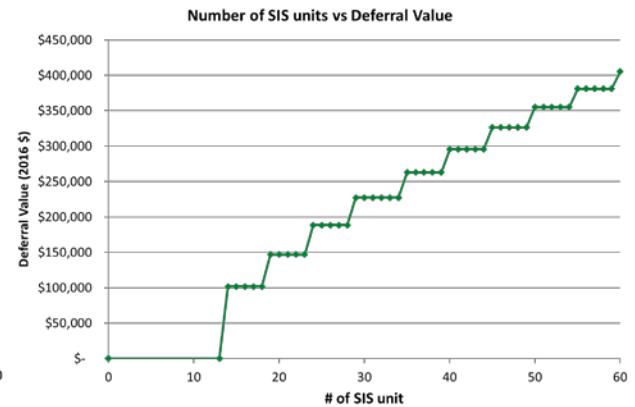
For the Jackson-Sunrise feeders and with utility dispatch of the SIS units, the upgrade can be deferred for 11 years, giving the SIS units a deferral value of \$141/(kW-yr.). This value per kW-yr. is reduced from the base case because the deferral value is spread out over a larger kW capacity of SIS units and PV. No deferral occurs in the customer or PV only control cases.

Figures 19 and 20 show how years of deferral and deferral value change with the number of SIS units installed under the high adoption forecast for PV and with utility dispatch of SIS units. Comparing figures 10 and 11 with figures 19 and 20 shows a slight change in deferral years and values from the base PV adoption forecast to the high PV adoption forecast. Figure 5-14 shows that under the high PV adoption forecast, 14 SIS units would need to be installed to defer the upgrade for one year. This is one unit fewer than under the base PV adoption forecast. Also, with 60 SIS units, the upgrade can be deferred for 11 years as opposed to 10 with the base PV adoption forecast.

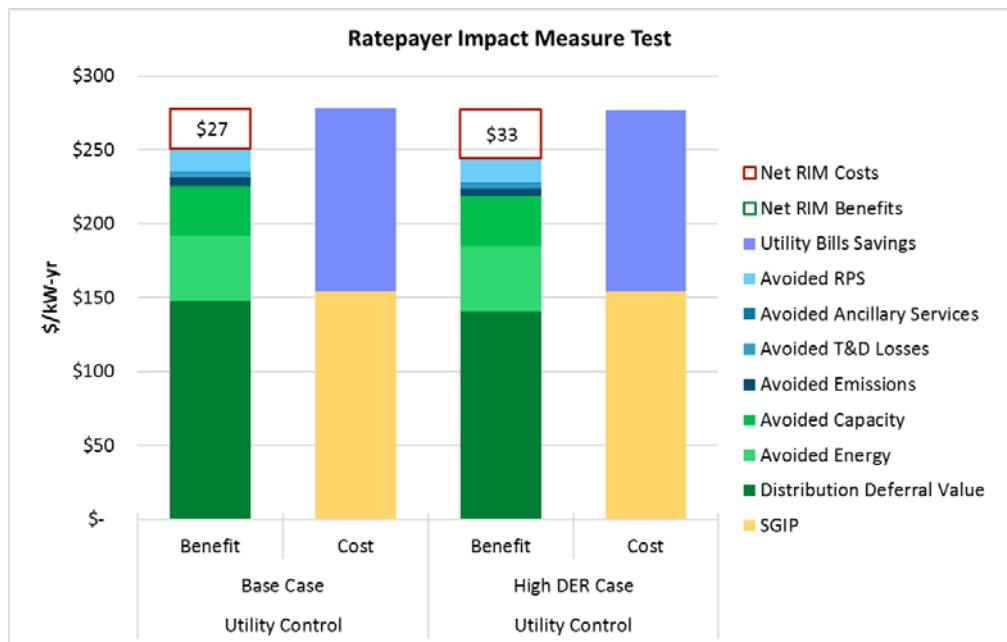
**Figure 5-14. Number of Years of Deferral as a Function of the Number of SIS Units on Jackson-Sunrise (High PV Adoption)**



**Figure 5-15. Deferral Value as a Function of the Number of SIS Units on Jackson-Sunrise (High PV Adoption)**



The effect of higher DER adoption on the RIM was investigated. Although the higher DER adoption resulted in 6 more years of deferral, the deferral value per kW of SIS units installed decreases by \$7/kW-yr., slightly increasing the net cost per kW-yr. to non-participant ratepayers. The RIM for the base DER adoption and high DER adoption cases are compared for Jackson-Sunrise below in Figure 5-16. The RIM is only compared in the utility dispatch case because there is no deferral value for the other control cases, meaning that the RIM is only effected by the higher DER adoption in the utility dispatch case.

**Figure 5-16. Comparison of RIM Tests for Base and High DER Adoption Cases.**

#### 5.6.1.2 Waterman-Grantline

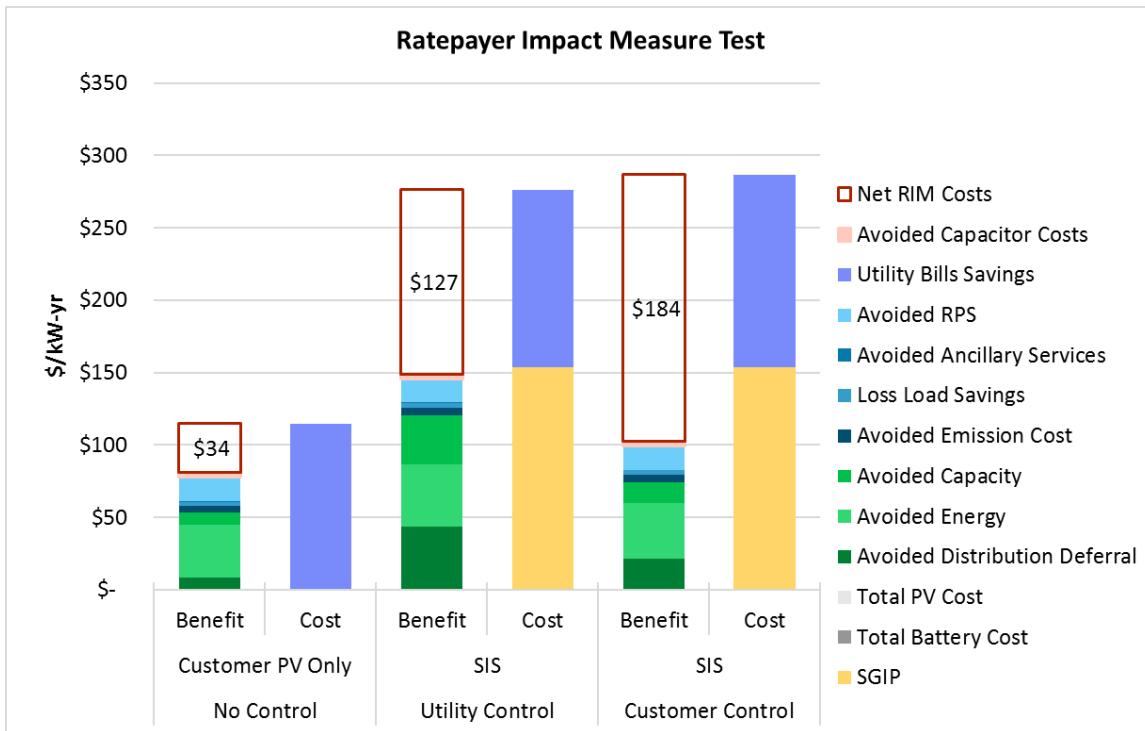
In the high DER adoption sensitivity, the distribution capacity upgrade is still only deferred for one year on the Waterman-Grantline feeders. The main difference between the base DER adoption case and high DER adoption case for the Waterman-Grantline feeders is that the per-kW deferral value of the adopted technology decreases from the values shown in Table 5-6 to those shown in Table 5-8.

**Table 5-8. Deferral Value by SIS Control Choice and DER Case for Waterman-Grantline (\$/kW-yr.).**

DER Adoption Case	PV Only	Utility dispatch	Customer dispatch (TOU)
Base	18	85	45
High	8	44	21

The high DER adoption sensitivity only affects the RIM through the reduction in deferral value, increasing the cost to non-participants on a per kW basis. Figure 5-17 shows the resulting RIM tests for the high DER adoption sensitivity on the Waterman-Grantline feeders.

**Figure 5-17. RIM Test for the Waterman-Grantline feeders in the High DER Adoption Sensitivity.**



## 5.6.2 TOU + CPP RETAIL TARIFF

As a sensitivity, we test the impact of a TOU + CPP retail tariff on RIM costs and benefits. We use SMUD's TOU+CPP retail tariff from its conservation day program described in section 4.1.1. Having a TOU+CPP retail tariff will only change customer bill savings when the SIS is under utility dispatch and will alter both utility avoided costs and bill savings under customer dispatch. Table 5-9 shows utility avoided cost benefits and bill savings under the utility or customer dispatch with a TOU or TOU+CPP retail tariff.

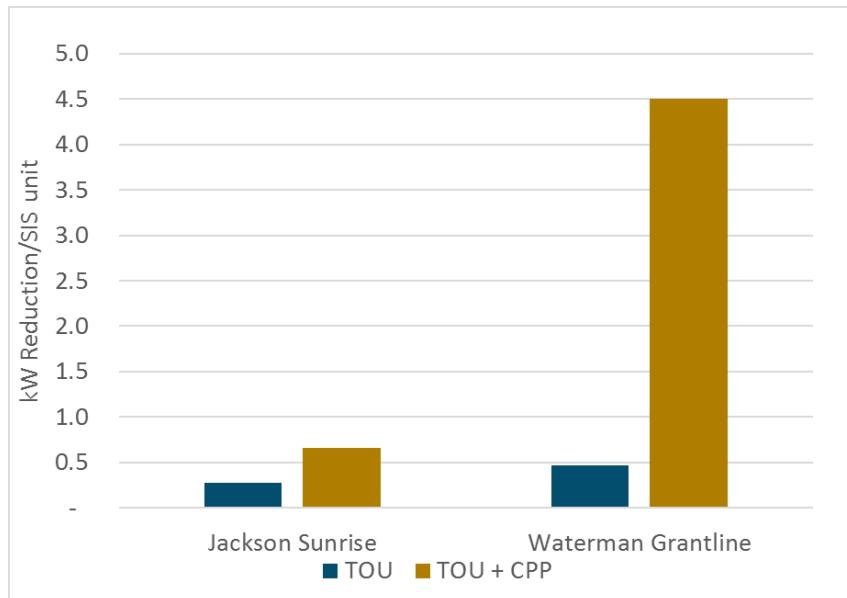
**Table 5-9. Change in Annualized RIM Costs and Benefits for Jackson-Sunrise with a TOU + CPP Retail Tariff (\$/kW-yr.).**

<b>Retail Tariff</b>	<b>Utility dispatch</b>		<b>Customer dispatch</b>	
	<b>Utility Avoided Costs</b>	<b>Bill Savings</b>	<b>Utility Avoided Costs</b>	<b>Bill Savings</b>
<b>TOU</b>	251	124	78	133
<b>TOU + CPP</b>	251	110	77	152

Under customer dispatch, the utility avoided costs are reduced slightly by moving to a TOU + CPP retail tariff because the TOU tariff does a better job of aligning customer incentives with the utility avoided costs. This is due to a difference between the avoided costs used in this study and SMUD's actual avoided costs, which are most likely accounted for when designing retail rates. The avoided costs used in this study reach their summer peak between 2 pm and 5 pm while SMUD's TOU+CPP rate has a critical peak period from 4 pm to 7 pm.

The TOU+CPP rate is effective in reducing the distribution feeder peak load. Figure 5-18 shows the reduction in feeder peak load under customer dispatch and the two retail tariffs. The load on Waterman-Grantline aligns well with the TOU+CPP Rate, resulting in a large peak load reduction. However, this does not result in extra years of distribution deferral.

**Figure 5-18. Distribution Feeder Peak Load Reduction with TOU or TOU+CPP Tariffs and Customer dispatch**



### 5.6.3 LARGER SIS UNITS

We analyzed the cost-effectiveness of larger SIS units on Jackson-Sunrise in the base case and under the various SIS control choices. The larger SIS units are assumed to have 19.6 kWh of energy storage, a maximum charge or discharge power of 6 kW, and 2.25 kW of PV. The cost tests were redone for this larger SIS unit.

The PCT for the larger SIS units is shown in Figure 5-19. The larger units result in a higher PCT net cost than in the base case for all SIS control choices.

**Figure 5-19. PCT for Larger SIS Unit Sensitivity.**

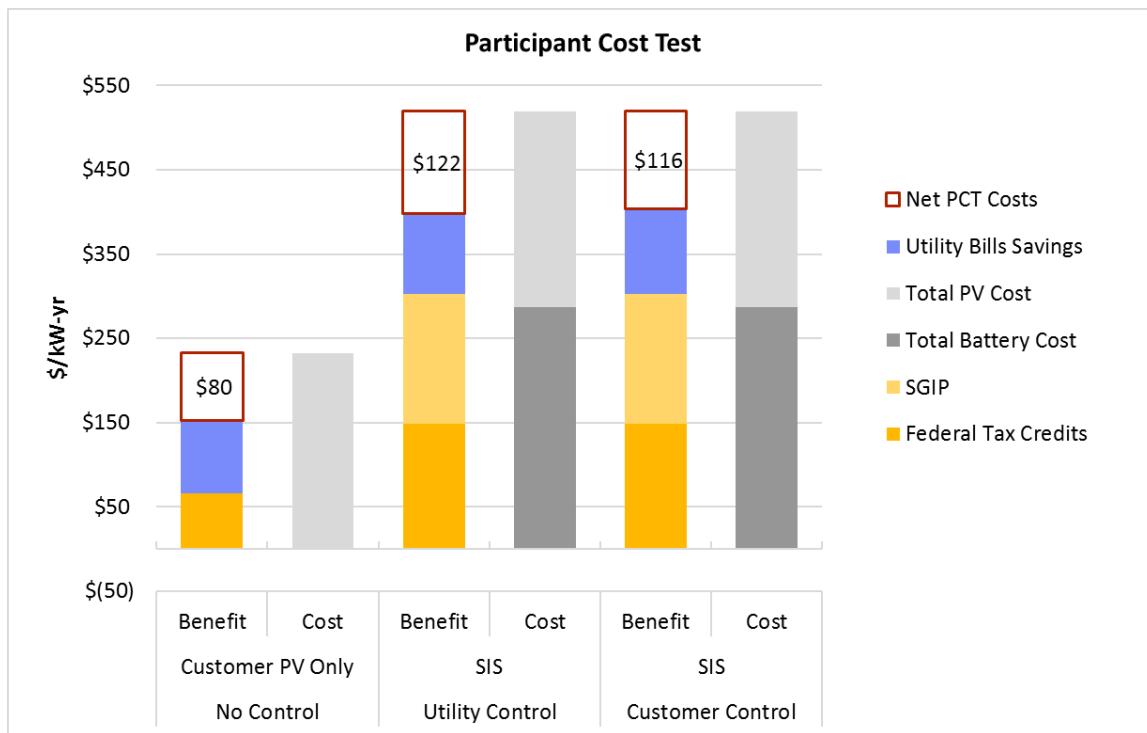


Figure 5-20 shows the TRC for the sensitivity with larger SIS units. When the units are controlled by the utility, the net cost is decreased compared to the base case by  $\$66/(\text{kW-yr.})$ . When the units are not controlled by the utility, the net cost of the larger units increases compared with the base case.

**Figure 5-20.TRC for Larger SIS Unit Sensitivity.**

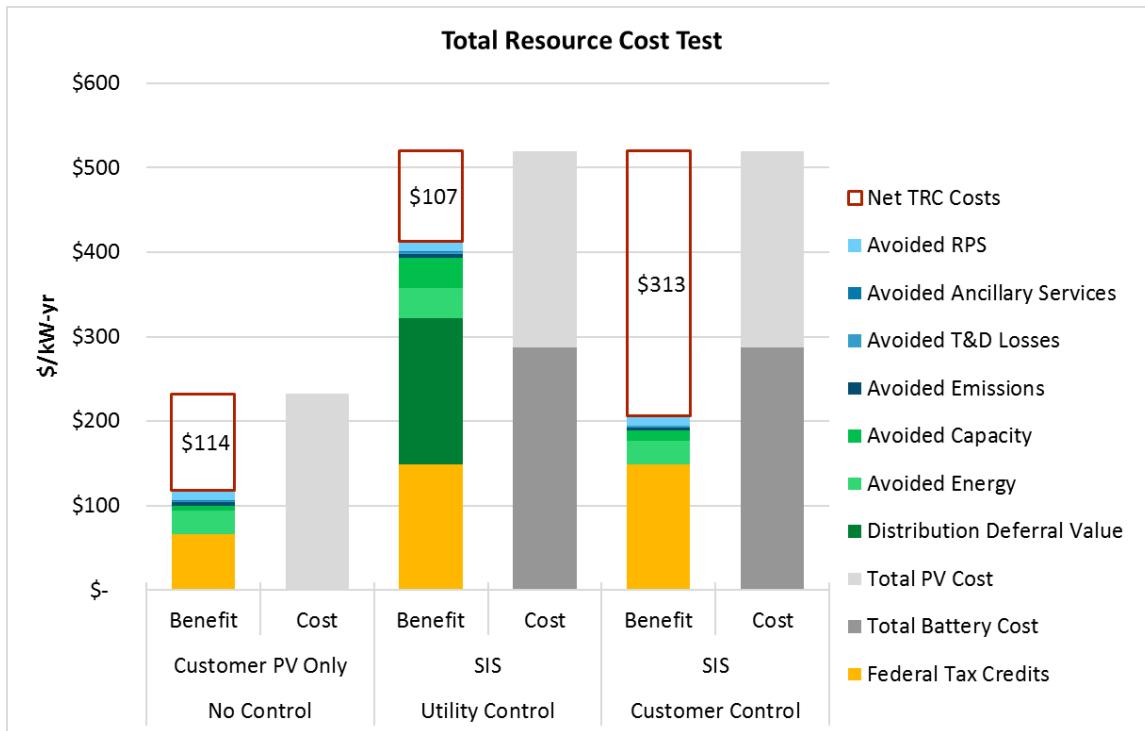
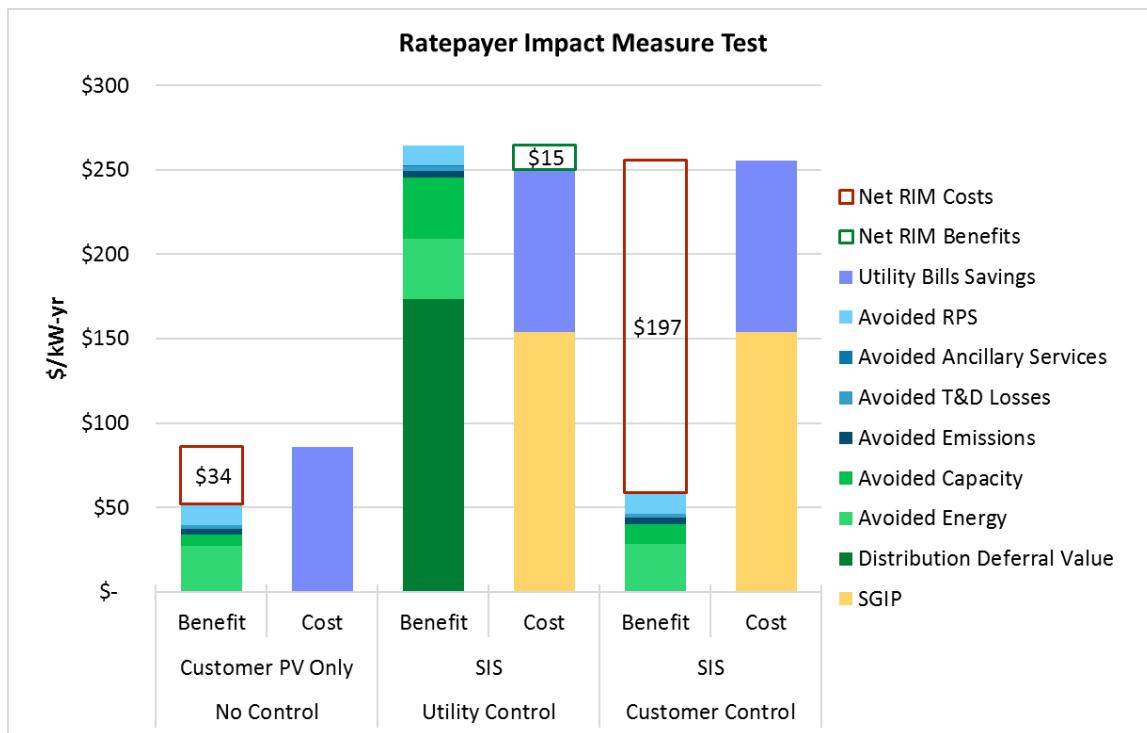


Figure 5-21 shows the RIM for the larger SIS unit. Generally, the larger battery does not do as well on a per kW basis for bill reduction or utility avoided costs other than distribution deferral. There is a larger distribution deferral value per kW because the upgrade can be deferred for more years than in the base case. These changes combine to give a positive RIM result under utility dispatch. The RIM is negative otherwise.

**Figure 5-21. RIM for Larger SIS Unit Sensitivity.**

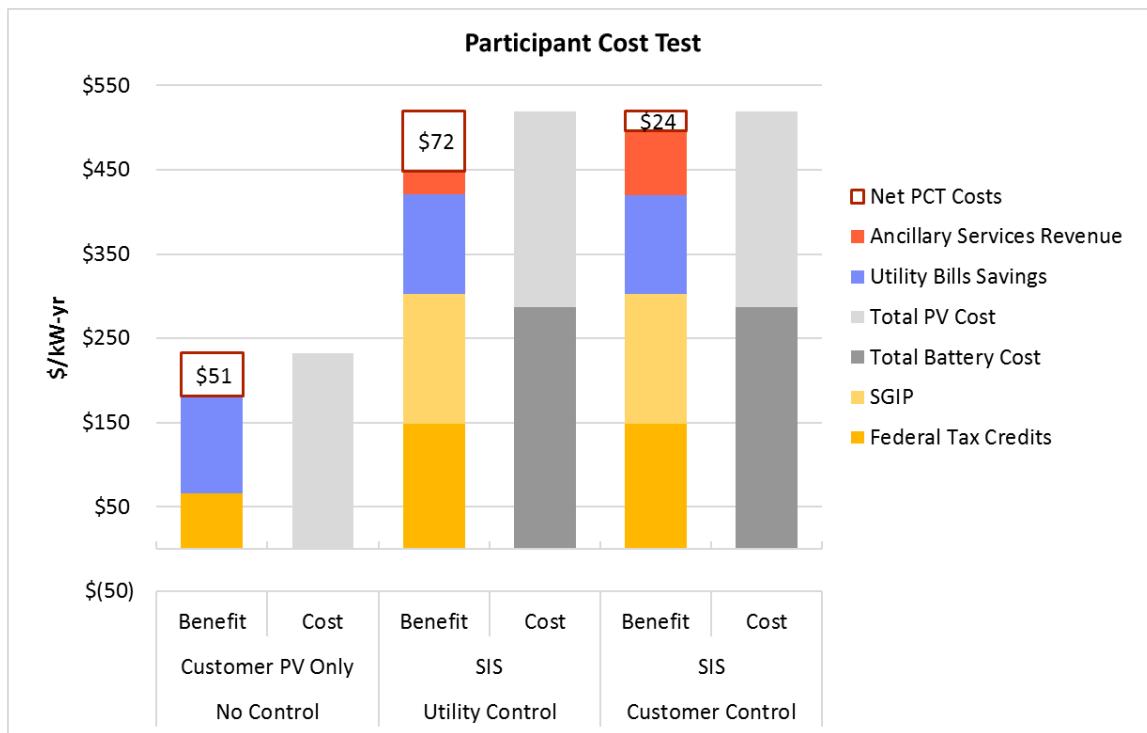


#### 5.6.4 OFFERING ANCILLARY SERVICES

This sensitivity explores the cost-effectiveness SIS units when they are able to offer ancillary services to the CAISO market. The CAISO ancillary services markets are represented using 2015 day ahead market prices. The iDER model is able co-optimize energy and ancillary services to maximize customer bill savings or utility benefits including distribution deferral. The cost tests were completed for the base case on the Jackson-Sunrise distribution feeder. We assume that any ancillary service revenue would ultimately go to the customers and that they are not components of the RIM test.

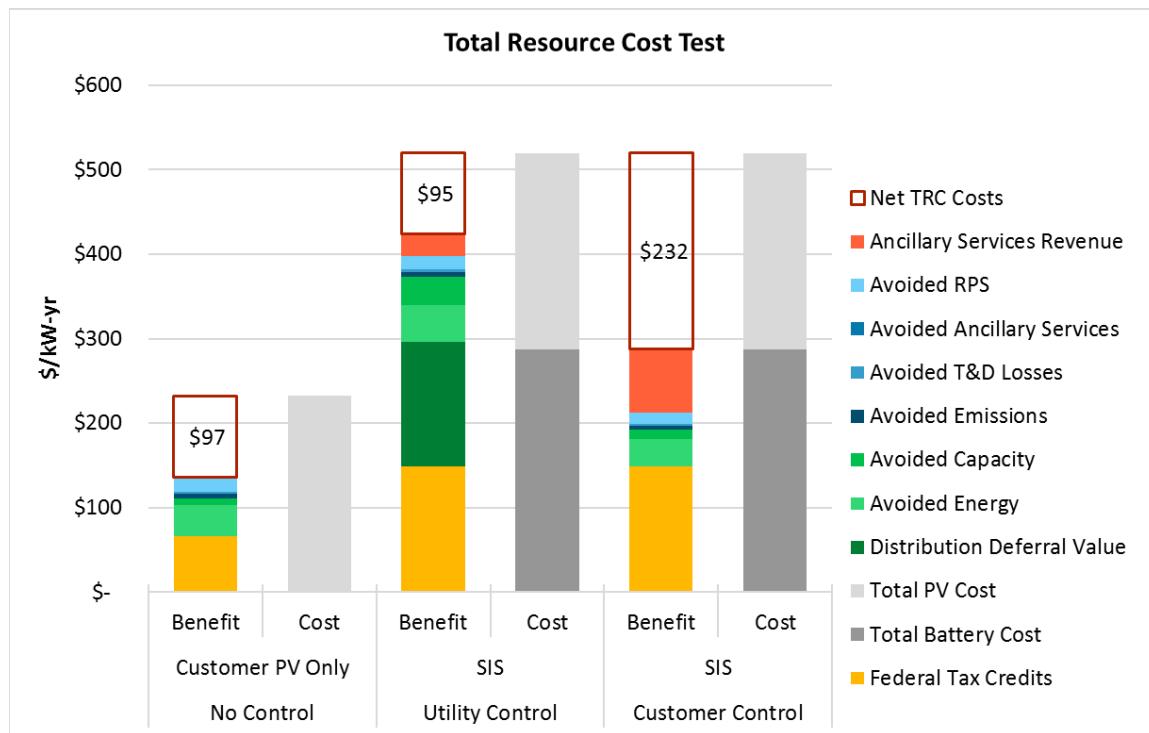
The PCT for when SIS units can provide ancillary services is shown in Figure 5-22. The net PCT cost is reduced by \$22/(kW-yr.) under utility dispatch and \$61/(kW-yr.) under customer dispatch.

**Figure 5-22. PCT When SIS Units Can Provide Ancillary Services.**

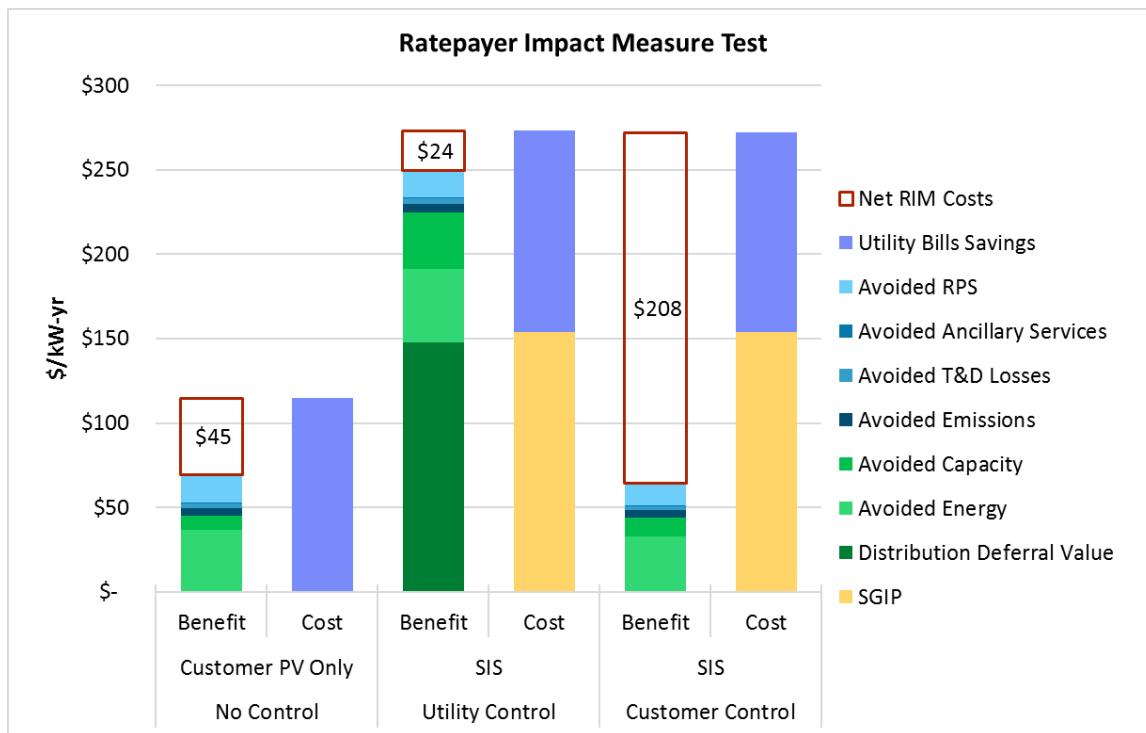


The TRC for when SIS units can provide ancillary services is shown in Figure 5-23. The net TRC cost is reduced by \$25/(kW-yr.) under utility dispatch and \$62/(kW-yr.) under customer dispatch.

**Figure 5-23. TRC Test When SIS Units Can Provide Ancillary Services.**



The RIM test is only affected indirectly through changes in the SIS dispatch. The RIM is shown in Figure 5-24, with a net cost to non-program ratepayers shrinking by \$3/(kW-yr.) in the utility dispatch case and \$1/(kW-yr.) under customer dispatch.

**Figure 5-24. RIM Test When SIS Units Can Provide Ancillary Services**

### 5.6.5 2016 TOU RETAIL TARIFF

The effect of changing the TOU retail tariff to SMUD's design for 2016 was investigated. Table 5-10 shows the resulting utility avoided costs and customer bill savings for the Jackson-Sunrise feeders. Under the 2016 TOU tariff customer bill savings increase under both utility and customer dispatch. Utility avoided costs decrease by \$1/(kW-yr.) under customer dispatch with the new tariff.

**Table 5-10. Change in RIM Costs and Benefits for Jackson-Sunrise with SMUD's 2016 TOU Retail Tariff.**

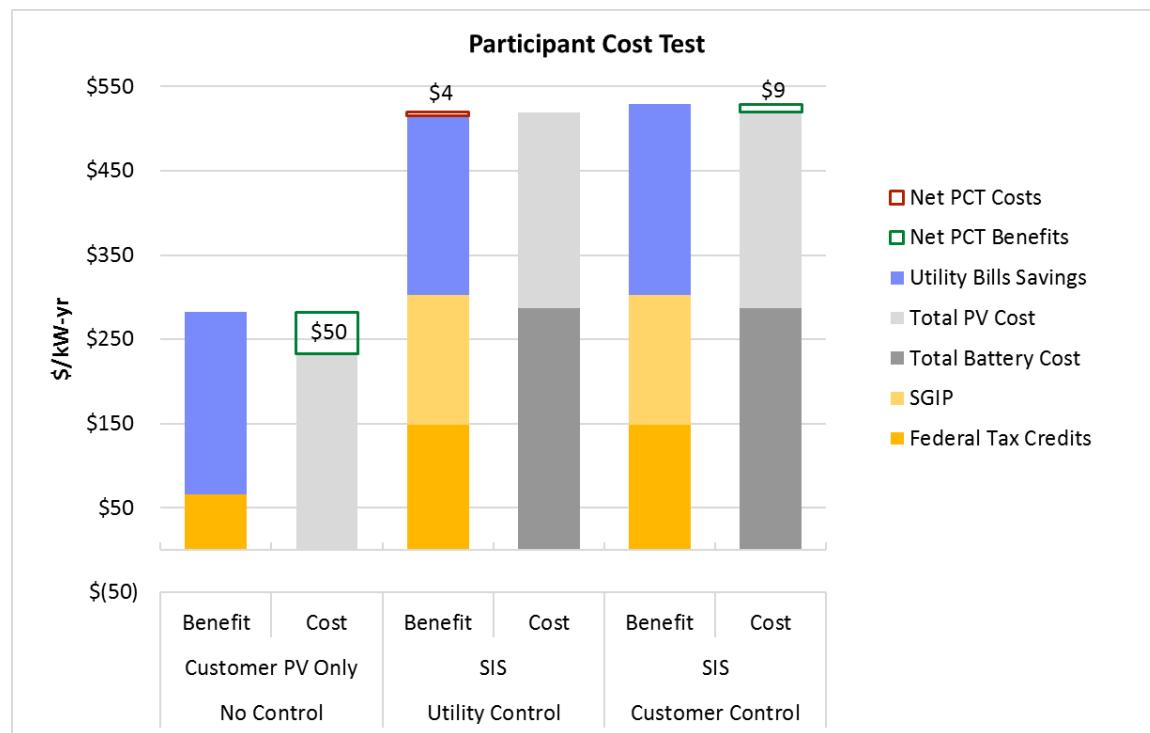
Retail Tariff	Utility dispatch		Customer dispatch	
	Utility Avoided Costs	Bill Savings	Utility Avoided Costs	Bill Savings
2015 TOU	\$251	\$124	\$78	\$133
2016 TOU	\$251	\$137	\$77	\$158

## 5.6.6 PG&E E-TOU TARIFF

This sensitivity explores the cost-effectiveness of SIS units under the PG&E E-TOU retail tariff. We assumed the base DER adoption case and the Jackson-Sunrise feeders for this sensitivity.

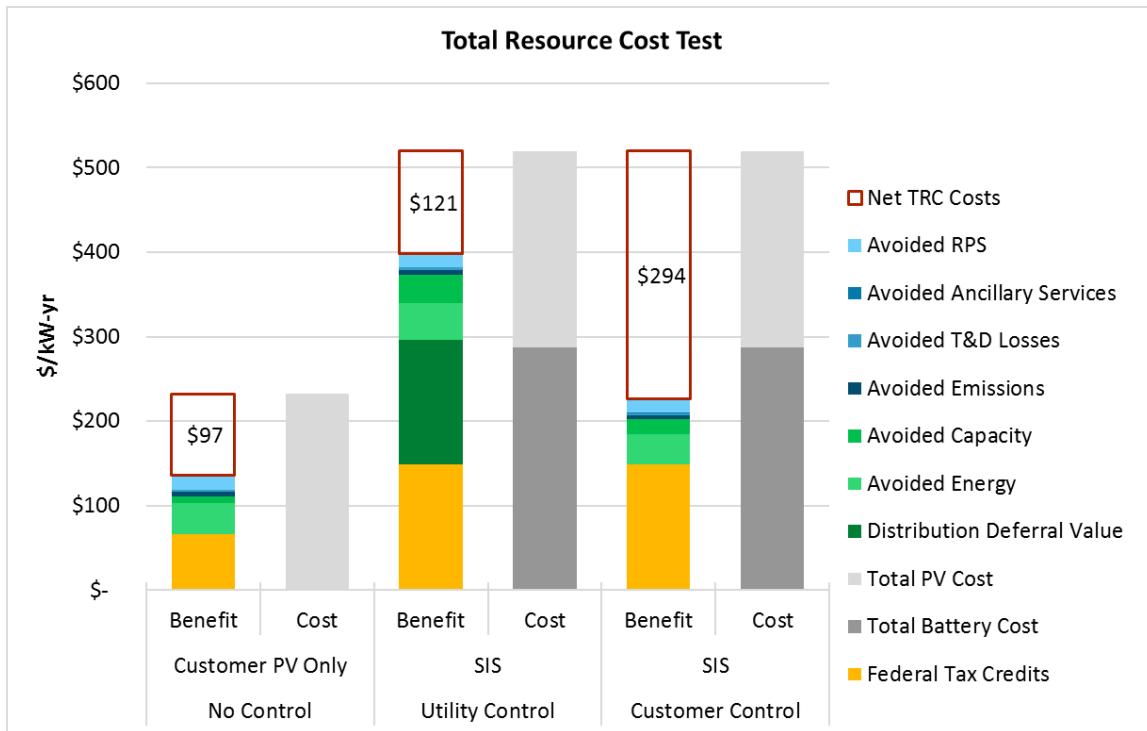
The PCT for the PG&E E-TOU rate is shown below in Figure 5-25. The PCT gives a positive participant benefit due to larger bill savings under the new rate. However, the customer would be best off with a PV system without storage.

**Figure 5-25. PCT for PG&E Tariff Sensitivity.**



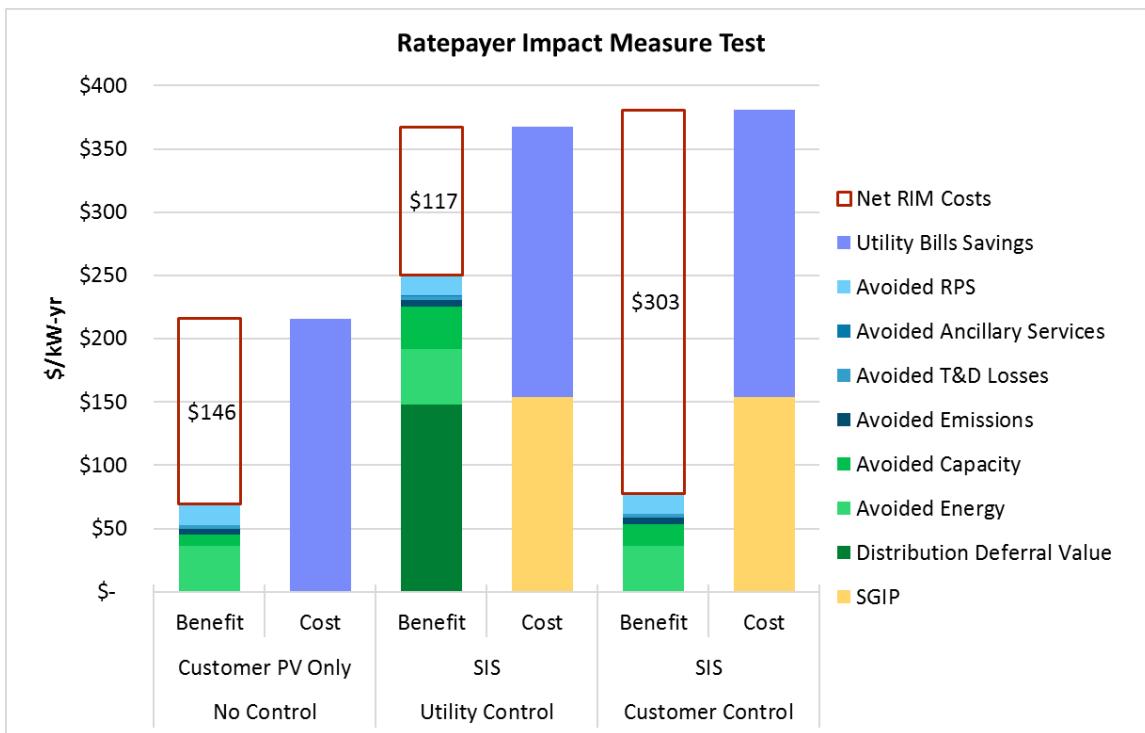
The TRC test for this sensitivity is shown in Figure 5-26. The TRC is only effected under customer dispatch, and has only a slight change. The net cost is reduced by less than \$0.5/(kW-yr.) compared with a customer under the SMUD TOU tariff.

**Figure 5-26. TRC for PG&E Tariff Sensitivity.**



The RIM test for this sensitivity is shown below in Figure 5-27. Under this tariff, the RIM shows larger net non-participant costs than under the SMUD tariff in all SIS control cases.

**Figure 5-27. RIM Test for PG&E Retail Tariff Sensitivity.**



### 5.6.7 PG&E A-10 RETAIL TARIFF WITH DEMAND CHARGE

PG&E's A-10 retail tariff applies to commercial and industrial customers with a monthly peak demand between 200 and 400 kW. This tariff makes for an interesting sensitivity, because it includes TOU energy prices and a monthly demand charge, which the other studied tariffs do not have. The monthly demand charge is a \$/kW charge based on the maximum 15-minute average value of the customer's demand in each month. Since the IDER model optimizes an aggregate model of homes and SIS units, it may underestimate the customer savings on the demand charge portion of the retail bill. This results from the sum of home load profiles being smoother or flatter than an individual home's load profile, leaving less opportunity for peak shaving.

When the SIS unit is under utility control, which does not consider customer bill effects, the customer demand charge can be increased significantly. It is doubtful customers would agree to such a program, and therefore we show cost test results assuming that customers would be afforded the same bill savings under utility control as under customer control.

Figure 5-28 Shows the PCT Test for the demand charge sensitivity. Under customer dispatch, the net PCT cost is reduced to \$34/kW-yr. due to the larger bill savings, including \$43/kW-yr. in demand charge savings. Because we assume that customers will have the same bill savings under utility control as under customer control, the PCT result is the same.

**Figure 5-28. PCT Test for Demand Charge Sensitivity.**

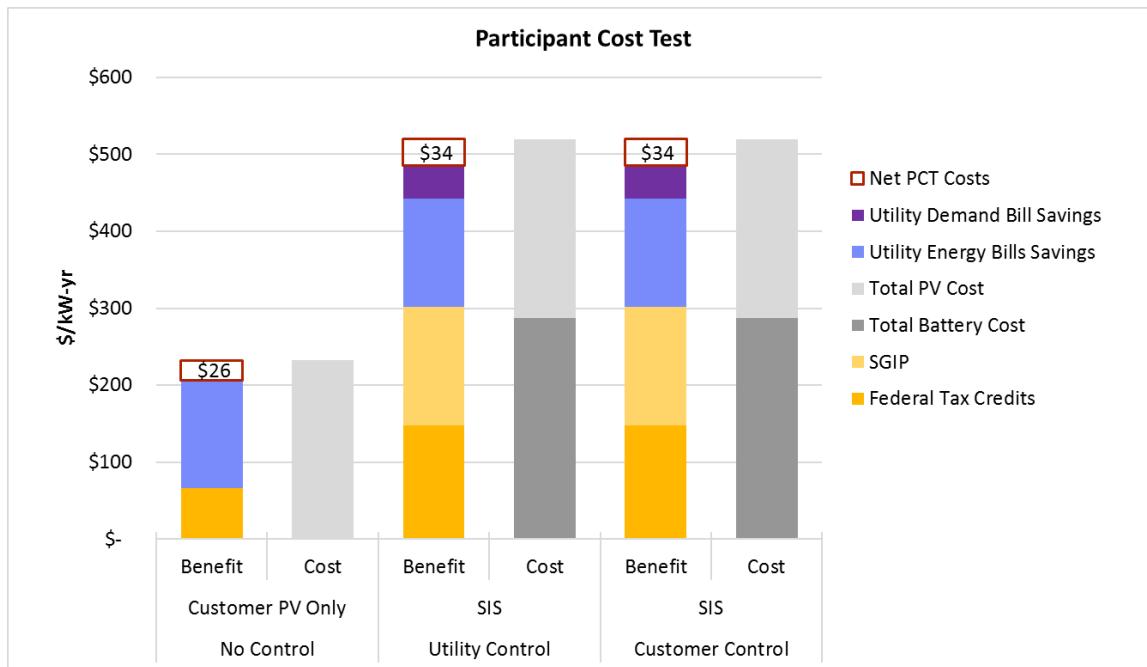
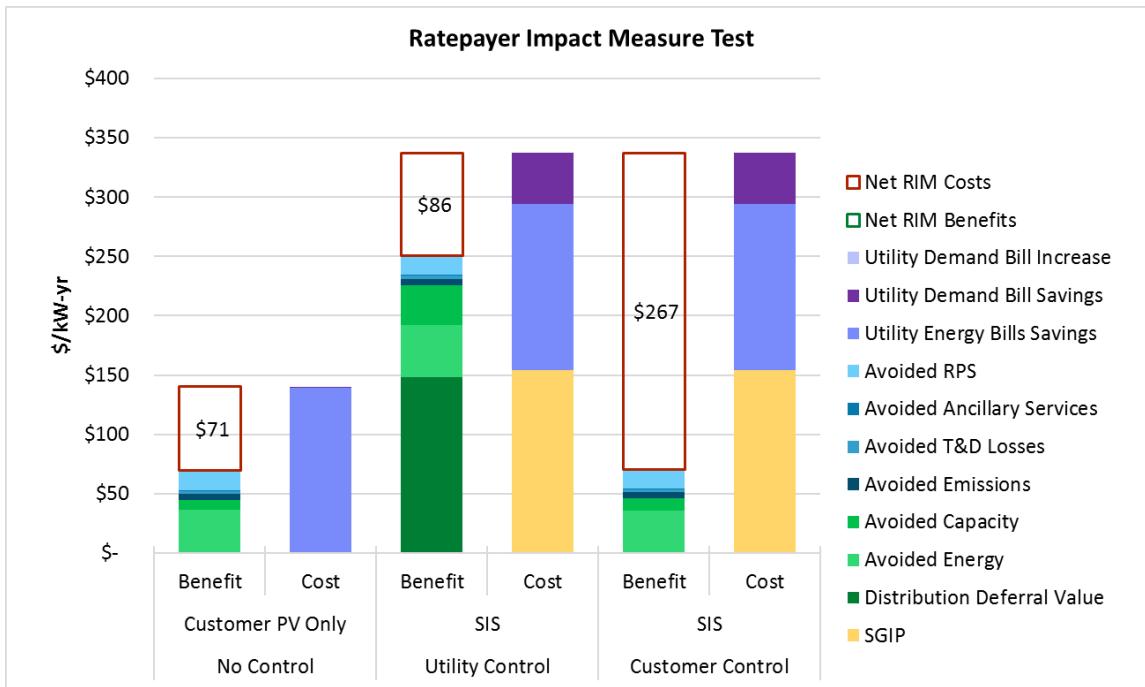


Figure 5-29 shows the RIM test for the demand charge sensitivity. The net RIM cost under customer dispatch is larger than in the base case due to the increased bill savings under the demand charge rate.

**Figure 5-29. RIM Test for Demand Charge Sensitivity.**

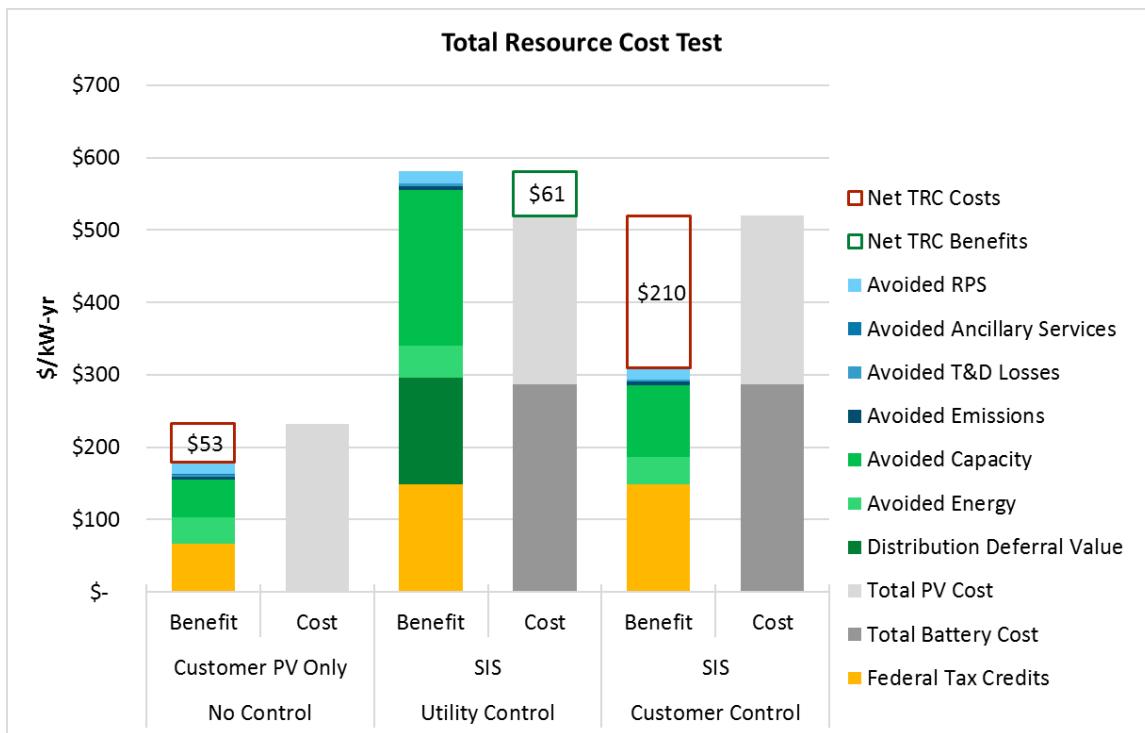


### 5.6.8 HIGH CAPACITY RESOURCE VALUE

This sensitivity explores the economics of SIS units with higher capacity or resource adequacy values. With significant renewable procurement and slower load growth, California currently has excess capacity, which keeps prices for bilateral RA contracts relatively low, on the order of \$30/kW-yr. In constrained areas, Local RA can have higher value. E3's research of FERC's EQR database found average prices of \$172/kW-yr. paid by SCE to large generators in the LA Basin. WECC's Transmission Expansion Planning Policy Committee (TEPPC) calculates the cost of new entry (CONE) for an aeroderivative combustion turbine as \$250/ kW-yr. The cost for new capacity in the LA Basin, where new generation is more difficult to permit and build would be expected to be even higher.

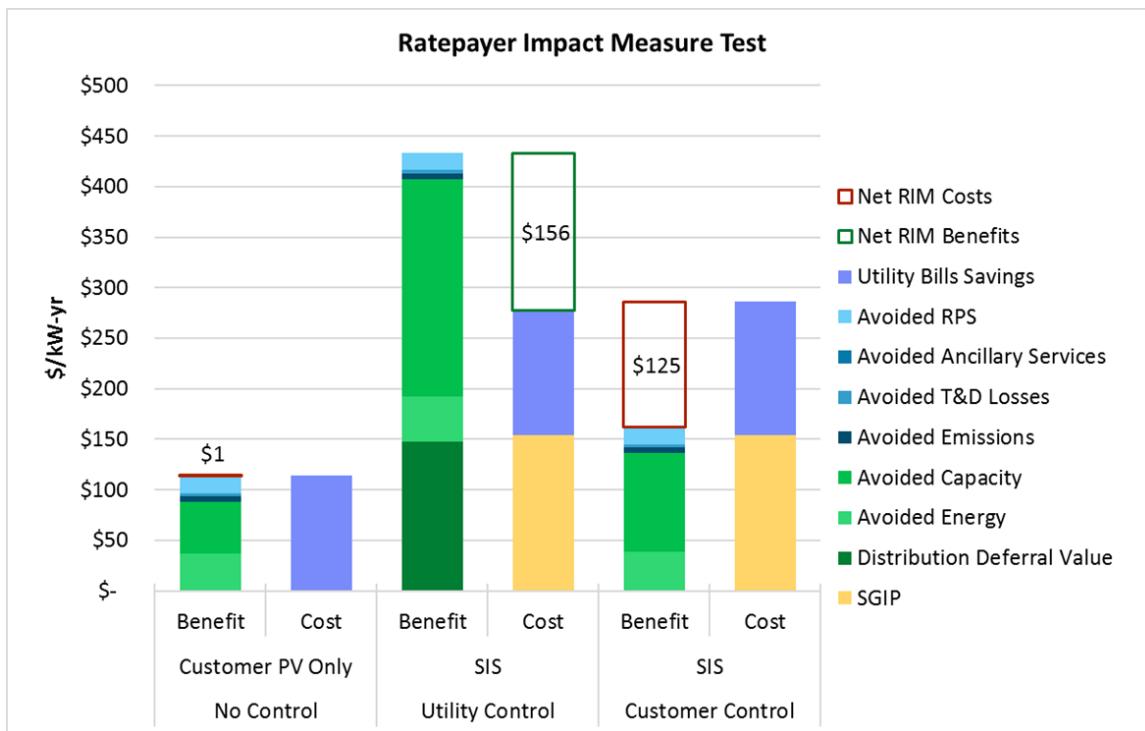
Here we present the TRC and RIM results for a sensitivity with a high capacity value of \$250/kW-yr. Results for the TRC of SIS units on Jackson-Sunrise are shown in Figure 5-30. Under utility dispatch, there is a positive TRC, with a levelized value of \$216/kW-yr. of avoided capacity cost being attributed to SIS units.

**Figure 5-30. TRC for Jackson-Sunrise with a Capacity Value of \$250/kW-yr.**



Results for the RIM of SIS units on Jackson-Sunrise are shown in Figure 5-30. Under utility dispatch, there is a net RIM benefit, while there is a net RIM cost in the other SIS control cases.

**Figure 5-31. RIM for Jackson-Sunrise with a Capacity Value of \$250/kW-yr.**



### 5.6.9 RELIABILITY VALUE

The cost-test results presented herein do not include the value of reliability for the retail customers. This because estimates of customer reliability vary widely. Residential customers typically indicate a low willingness to pay to improve reliability and value of service estimates are correspondingly low. On the other hand, early adopters have shown a clear willing to pay substantial costs for residential storage systems whose primary value is in providing backup power. Commercial value of service is much higher, but still, the demonstrated willingness to pay for reliability is typically much lower than values suggested by surveys. Using SMUD SAIDI and SAIFI data, we calculate the reliability value of battery storage based on the length of outage it can avoid for the customer.<sup>16</sup> We use interruption cost data provided by the 2015 LBNL study (Sullivan, Schellenberg, & Blundell, 2015).

<sup>16</sup> SAIDI: System Average Interruption Duration Index, SAIFI: System Average Interruption Frequency Index

**Table 5-11: SMUD Reliability Statistics**

Year	Total System		Jackson-Sunrise	
	SAIDI	SAIFI	SAIDI	SAIFI
2014	54.3	1.00	61.93	0.64
2015	70.9	1.35	90.33	0.51

**Table 5-12: LBNL Outage Cost (\$/kW) by Length of Outage**

Customer Class	Momentary	30 minutes	1 hour	4 hours
Residential	\$2.6	\$2.9	\$3.3	\$6.2
Commercial	\$188	\$237	\$295	\$857
Industrial	\$1,539	\$18.7	\$21.8	\$48.4

Using the reliability statistics provided by SMUD, we calculate the probability that a customer on the Jackson-Sunrise feeders will experience an outage of a particular duration. Because we are evaluating SIS units with a maximum duration of just over 2 hours, we look at momentary, 30 minutes 1 hour and 2 hour outages. The probability of an outage of any duration occurring during the year is less than 0.2% and outages of shorter durations have a higher probability than longer duration outages. We multiply the probability of a customer experiencing an outage of a given duration times the interruption cost provided by the LBNL report to calculate the value the battery provides in backup power (Table 5-13). If the battery is kept full throughout the year to provide reliability the total value for a residential customer is \$1.90/kW-yr. For a commercial customer the value is much higher at \$201/kW-yr.

**Table 5-13: Reliability Value by Length of Outage Avoided with 2 Hour Battery (\$/kW).**

Customer Class	15 Minute	30 minutes	1 hour	2 hours	Total
Residential	\$0.57	\$0.50	\$0.45	\$0.42	\$1.9
Commercial	\$44.08	\$41.22	\$39.88	\$76.21	\$201
Industrial	\$161.61	\$3.25	\$2.95	\$4.30	\$172

We also calculate the total value provided when the battery is dispatched under utility dispatch peak load reduction, based on the battery SOC in each hour (Table 5-14). When the battery is operated for utility benefit and has available stored energy, in an outage, the stored energy would be available for customer

use serving household loads. The battery has some available energy during most hours of the year and thus provides a reliability value of \$1.20/kW-yr. or \$126/kW-yr. for a residential or commercial customer respectively, roughly 60% of the value of a battery that remains full throughout the year.

**Table 5-14: Total Reliability Value (\$/kW) For a 2-hour battery on Jackson-Sunrise feeders**

Customer Class	Utility dispatch	Full Battery all Year
Residential	\$1.20	\$1.90
Commercial	\$126	\$201
Industrial	\$108	\$172

## 5.7 Ratepayer Neutral Incentive Analysis

In this section we discuss the maximum ratepayer neutral incentives that a utility could pay to customers for installing SIS units in the scenarios studied. SMUD customers already receive an SGIP adoption incentive, but this incentive was shown to result in a net cost to non-adopting ratepayers in cases other than the large SIS unit, PG&E demand charge tariff, and high generation capacity price sensitivities under utility dispatch. To calculate the maximum ratepayer neutral incentive, we subtract the customer's bill savings from the utility benefits shown in the RIM test.

Table 5-15 shows the maximum ratepayer neutral incentive for the base case and sensitivities analyzed in sections 5.5 and 5.6. The table also shows the utility benefits and customer bill savings used to calculate the maximum incentive. The incentive depends on the value that the SIS unit creates for the utility, which can largely depend on distribution deferral value. This results in a maximum incentive that varies based on the location of the SIS unit in the distribution network. The distribution network location is indicated in the column marked Feeder, with JS representing Jackson-Sunrise and WG representing Waterman-Grantline. The column labeled 'PCT w/o SGIP' gives the net participant cost or benefit without an SGIP incentive for each scenario. In the ancillary services sales case, we have accounted for the ancillary service revenues as a customer benefit in the No SGIP PCT.

There are two cases where the maximum incentive is larger than the SGIP incentive: the large SIS unit sensitivity and the maximum generation capacity price sensitivity. The only case where the maximum ratepayer neutral incentive would be sufficient encourage adoption is the maximum generation capacity price sensitivity.

**Table 5-15. Maximum Ratepayer Neutral Incentives for Adoption of SIS Units Under Utility dispatch. (\$/kW-yr.)**

Case	Feeder	Utility Benefits	Customer Bill Savings	Maximum Utility Incentive (\$/kW-yr.)	PCT w/o SGIP
<b>Base Case</b>	JS	\$251	\$123	<b>\$128</b>	<b>-\$248</b>
	WG	193	123	<b>70</b>	<b>-248</b>
<b>High DER</b>	JS	244	123	<b>121</b>	<b>-248</b>
	WG	149	123	<b>26</b>	<b>-248</b>
<b>TOU+CPP Tariff</b>	JS	251	110	<b>140</b>	<b>-261</b>
<b>Larger SIS Units</b>	JS	265	96	<b>169</b>	<b>-239</b>
<b>Ancillary Services</b>	JS	250	119	<b>131</b>	<b>-225</b>
<b>2016 TOU</b>	JS	251	137	<b>114</b>	<b>-234</b>
<b>PG&amp;E TOU Tariff</b>	JS	251	227	<b>24</b>	<b>-144</b>
<b>PG&amp;E Demand Charge Tariff</b>	JS	251	183	<b>68</b>	<b>-184</b>
<b>\$250/kW-yr. Capacity Value</b>	JS	433	123	<b>310</b>	<b>-248</b>

## 5.8 Summary of Findings

The value of customer adoption of SIS units has been investigated from many perspectives and in many sensitivities in the case study above. The only scenario to show a positive TRC benefit is when generation capacity is valued at \$250/kW-yr. The only scenario with a positive PCT benefit was under the PG&E TOU tariff. Two scenarios showed a positive RIM benefit: larger SIS units, and high generation capacity price.

On the Jackson-Sunrise feeders, customer adoption of an SIS unit and giving the utility dispatch reduces the RIM cost to non-participant customers compared with adoption of only solar PV. Using an SIS for sales of ancillary services appears attractive for end use customers, but is less attractive to the utility. In two cases, the maximum ratepayer neutral incentive that a utility can provide to customers purchasing an SIS

unit was greater than the SGIP incentive. These cases are larger SIS units and with high generation capacity prices. The only scenario where the maximum ratepayer neutral incentive is large enough to make a positive PCT and adequately incentivize customer adoption of SIS units is the high generation capacity price scenario.

The results of this case study makes it clear that the value of SIS adoption to a utility and its ratepayers depends highly on location and how it is operated. Distribution upgrade deferral can account for more than half of the value of an SIS unit to the utility. Utility dispatch of SIS units maximizes the benefits to utilities and ratepayers, while customer dispatch results in the largest customer bill savings. The increase in utility benefits is larger than the decrease in bill savings when switching the SIS unit from customer dispatch to utility dispatch. If SIS units are under customer dispatch, the design of retail rates is critical to align utility and customer incentives. For instance, on the Jackson-Sunrise feeders, the SIS units had a large distribution deferral value under utility dispatch, but none under customer dispatch. If customers did purchase an SIS, the utility would be willing to pay customers for control so that it could reduce costs for all ratepayers.

# 6 Program Design

The energy storage industry continues to show significant growth year-over-year, although it is still an emerging market with plenty of room for additional growth and maturation. The record 243% growth in 2015 over 2014 amounted to 221MW installed, only 15% of which was behind-the-meter storage.<sup>17</sup> The research outlined in this paper demonstrates that there is a value to the utility for residential behind-the-meter PV integrated with storage systems. The storage industry is in the early commercialization phase for the residential sector where upfront costs of the technology are a barrier to adoption. To fully harness the value of a PV integrated storage system and to overcome the storage technology cost barrier, properly designed utility programs are needed to transform the market. This section provides a review of existing residential storage pilots and programs to understand the current landscape, a framework for developing a program design based upon program design considerations, components of possible incentive program designs, and two specific program details for consideration in design. The framework is laid out in a way that utilities can pick and choose the characteristics that meet their use case(s) to create a successful program design. Following the description of the program design framework, three example program configurations are discussed. The first example shows how the real world use case of SMUD, analyzed earlier in this report, fits into the program design process. The second example again uses the program design framework but in a hypothetical use case to show how the framework operates under a different set of circumstances. Finally, a third example is given that focuses on a unique whole house smart rate option. The program design framework provided will support the development of effective PV integrated storage programs which will be an important tool for utilities to realize the benefit of behind-the-meter storage in supporting the resiliency and stability of the grid.

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<sup>17</sup> <http://www.greentechmedia.com/articles/read/us-energy-storage-market-grew-243-in-2015-largest-year-on-record>

## 6.1 Review of Existing Storage Pilots and Programs

Residential storage programs are still in the early stages of development and deployment. Almost all current programs are new or a pilot of one type or another, with the exception of California's Self Generation Incentive Program (SGIP) which has been incentivizing advanced energy storage since 2009. Included below is a summary of residential storage programs across North America and Australia.

**Table 6-1. Existing Storage Pilots and Programs**

	<b>Provider</b>	<b>Location</b>	<b>Program Name</b>	<b>Incentive Type</b>	<b>Ownership Type</b>	<b>Incentive or Lease Details</b>	<b>Program Type</b>	<b>Additional Information</b>
1	Green Mountain Power <sup>18</sup>	Vermont	TESLA Powerwall	Monthly Utility Payment for Control	Customer	\$31.76/month incentive	Storage Only	Utility will discharge battery at specific times to lower their energy costs and capacity and transmission expenses. 17 year pay back
2	Green Mountain Power	Vermont	TESLA Powerwall	None	Utility Lease	Customer pays \$1.25/day	Storage Only	See above. Interest free 17-year installment plan
3	Green Mountain Power	Vermont	TESLA Powerwall	None	Customer	Customer can purchase Tesla Powerwall for \$6,501	Storage Only	No utility control
4	Marin Clean Energy <sup>19</sup>	California	None	Monthly Utility Payment for Control	Customer	\$5/month incentive for 50% use of battery and \$10/month incentive for 100% use of battery	Storage Only	Battery vendor neutral
5	Pacific Gas & Electric, Southern California Edison, Southern California Gas, San Diego Gas & Electric <sup>20</sup>	California	Self-Generation Incentive Program (SGIP)	Equipment Incentive	Customer	\$1.31/watt incentive in 2016 and declining 10% every year (incentive structure may change in mid-2016)	Storage Only	Battery vendor neutral. Storage must be used for load shifting via at least a time-of-use rate and not just back-up
6	Ergon Retail <sup>21</sup>	Australia	Hybrid Energy Service Trial	None - Equipment installed for free	Utility	Customer pays \$89/month for 12 months	Storage + PV	Customer estimated to receive \$200-\$700 annual savings as well as having back-up power. Customer automatically participates in DR and will be on a time-of-use tariff with a

<sup>18</sup><http://products.greenmountainpower.com/product/tesla-powerwall/><sup>19</sup> Interview 12/15/2015<sup>20</sup> <https://www.selfgenca.com/documents/handbook/2016><sup>21</sup> <https://www.ergon.com.au/retail/residential/hybridenergy>

	Provider	Location	Program Name	Incentive Type	Ownership Type	Incentive or Lease Details	Program Type	Additional Information
								demand charge based on coincident system peak
7	PowerStream <sup>22</sup>	Ontario, Canada	POWER.HOUSE Pilot	None - Equipment installed for free	Utility	Customer pays upfront cost and monthly service fee	Storage + PV	20 customers and the effort is funded by a grant from the Independent Electricity System Operator (IESO) Conservation Fund
8	Xcel Energy <sup>23</sup>	Colorado	Innovative Clean Technology – Stapleton	None	Utility	Info not available	Storage + PV	Xcel will install and test six batteries on the customer side at residences with existing PV and six batteries on the utility side to understand storage's potential to manage high penetration of PV on distribution system feeders
9	Sacramento Municipal Utility <sup>24</sup>	California	2500 R Midtown	None	Customer	None	Storage + PV + Smart Appliances	In 2014, a partnership between SMUD, Sunverge and Pacific Housing resulted in 34 homes built with PV, storage and smart appliances that were designed to be zero-net-energy
10	Arizona Public Service <sup>25,26</sup>	Arizona	Solar Innovation Study 75	None - Equipment installed for free	Utility (transfer to customer after 5 years)	None	Storage + PV + Smart Appliances	System will include PV with advanced inverter at 75 homes and some locations will receive battery storage, load controllers, home energy management technology, and/or high efficiency HVAC. Customers will be on a TOU rate with a demand charge to test how customers respond to price signals.
11	SolarCity <sup>27</sup>	Hawaii	Smart Energy Home	None	3rd Party or Customer	Customer pays \$0.26/kWh for rental	Storage + PV +	System includes PV, Tesla battery, Nest thermostat, Steffes smart electric

<sup>22</sup> <https://www.powerstream.ca/innovation/power-house.html>

<sup>23</sup> <https://www.colorado.gov/pacific/dora/news/puc-approves-xcel-energy-request-two-clean-technology-demonstration-projects>

<sup>24</sup> <http://smartgridcustomereducation.com/presentations/SGCES-LupeLimenez-SMUD.pdf>

<sup>25</sup> <https://www.aps.com/en/globalservices/installers/Pages/solar-innovation-study.aspx>

<sup>26</sup> <http://www.utilitydive.com/news/how-arizona-public-service-is-preparing-for-the-grid-of-the-future/413667>

<sup>27</sup> <http://www.greentechmedia.com/articles/read/SolarCitys-System-For-Self-Supply-in-Hawaii-Includes-PV-Storage-Water-He>

	Provider	Location	Program Name	Incentive Type	Ownership Type	Incentive or Lease Details	Program Type	Additional Information
						or can purchase system for \$4.50/watt	Smart Appliances	heater, and a gateway to control and optimize the system. Participating in Customer Grid Supply (CGS) which only credits surplus power at about $\frac{1}{2}$ the retail rate for the next two years or the Customer Self-Supply (CSS) tariff that only allows for inadvertent export with zero compensation.
12	Glasgow Electric Plant Board <sup>28</sup>	Infotricity	Kentucky	Info not available	Info not available	Info not available	Storage + Smart Appliances	\$7.4 million grant to install heat pump water heaters and smart thermostats in 330 homes. Now adding Sunverge and smart appliances to 44 homes. Customers do not receive back-up power or PV. 60 DR event days a year up to 3 hours long. Utility controls the equipment to pre-heat water at low-demand, pre-heat or pre-cool living spaces, and respond to DR events to benefit the grid and manage peak load.

<sup>28</sup> [http://www.elp.com/articles/powergrid\\_international/print/volume-20/issue-11/features/case-study-glasgow-epb-s-infotricity-key-tour.html](http://www.elp.com/articles/powergrid_international/print/volume-20/issue-11/features/case-study-glasgow-epb-s-infotricity-key-tour.html)

## 6.2 Program Design Considerations

As has been demonstrated throughout this paper, there are a variety of benefits and values that customer-sited residential storage integrated with solar can provide to a utility. To fully harness those benefits through an incentive program, the utility first needs to consider a variety of factors before choosing the program components that best fit the specific utility's goals. This section covers the various program factors to review. While the design is flexible and customizable, there isn't a "silver bullet" and one program is not going to meet all the goals of utility so it is important to narrow down priorities before designing a program.

### 6.2.1 UTILITY DRIVERS

- + California regulatory requirements
  - California AB 2514 requires all three CA IOUs to procure a combined storage capacity of 1.325 GW by 2020, of which 200 MW must be customer sited
  - SB 350 increases California's renewable portfolio standard to 50% by 2030. Storage can support the addition of intermittent renewables and support grid reliability
  - Local capacity requirements (LCR) in California allow a variety of technologies including storage. SCE acquired more than 250MW of energy storage under its LCR RFO authorized under the Long Term Procurement Plan (LTPP) proceeding to meet local capacity requirements in the Western LA Basin and Moorpark sub-areas. SDG&E is also in the process of procuring resources for their LCR requirements and storage is an eligible resource.
  - California AB 327 requires CA IOUs to consider DERs as part of their distribution system planning process for deferment of traditional infrastructure projects when cost effective. Storage (along with DR) are expected to be important contributors to alleviating distribution peak capacity constraints.
- + Customer benefits
  - Maintain relationship with customers as a trusted energy advisor
  - Provide unique value to customers
  - Increase customer control over bills

- Support transition away from net-energy metering tariffs while still supporting customers interest in increased renewables and bill savings
- Grid benefits to all customers
- + Financial benefits
  - Transmission deferral
  - Distribution deferral
  - Transmission congestion relief
  - Resource adequacy
  - Reduce energy costs through economic dispatch
  - Ancillary services (spin/non-spin reserve, frequency regulation, voltage support)
  - Reduce peak demand
  - Mitigate grid impacts of the projected evening ramp
- + Grow industry knowledge and experience with storage during the early commercialization phase
- + Support integrated demand side management corporate strategy

### **6.2.2 UTILITY CONCERNS**

- + System impacts of storage – lack of predictability in increases and decreases in load
- + Reduction of revenue
- + Reduction of customer demand
- + Introduction of a third party relationship that interferes with utility customer relationship – third party managed resources
- + Costly infrastructure upgrades needed to integrate with utility systems for transparency, monitoring and unit control – utility controlled systems
- + Customer equity in distribution of infrastructure costs

### **6.2.3 CUSTOMER DRIVERS**

- + Supporting integration of more renewables on the grid
- + Investing in new and ‘cool’ technology

- Understanding where storage is in the market adoption curve will allow the program to target the correct customer type. Currently batteries are being adopted by Innovators and Early Adopters that are interested in new and ‘cool’ technology
- + Reducing electricity costs and realizing bill savings
  - More market research needed as batteries are generally not cost effective with existing residential rate structures
- + Procuring of an Emergency back-up resource – more of a driver in areas of low grid reliability
- + Harvesting value from DER in areas where NEM rates are not lucrative to recover investment costs
- + Going off the grid for environmental or political reasons

#### 6.2.4 STORAGE INDUSTRY BARRIERS

- + Cost
  - High upfront capital investment cost
  - Low rate of capital recovery (relatively)
  - Time-independent residential tariff structures without demand charges
- + Equipment reliability
- + Inefficiency in interconnection and permitting due to unfamiliarity with the technology
- + Uncertainty in regulatory markets
- + Lack of trained installers

### 6.3 Integrated Storage Program Components

Determining program drivers, goals and industry barriers is the first step in developing a successful integrated PV and storage program, as was discussed in the previous section. The next step is to review the various program components and determine which set of components best overcome the industry barriers and achieve the program goals. This section focuses on the use case, benefits and drawbacks of two major components of a program: incentive options and ownership models.

### 6.3.1 INCENTIVE OPTIONS

Current storage pilots have mostly elected to forego an incentive to the customer as seen in Table 6-1. Instead, many pilots are providing the equipment free to the customer (a common quality of pilots) which supports the assertion that utilities feel there is still a lot to learn about storage. However, as the storage industry matures programs, instead of pilots, will be needed to push the market forward and incentives will be a key factor to overcome the major hurdle of first cost that storage battles with today. There are three main incentive options to consider when developing an integrated storage program: an equipment incentive, a monthly utility payment for control of the system, or a specific rate.

#### 6.3.1.1 *Storage Equipment Incentive*

+ Use case

- Market Maturity: Emerging Technology/Early Adoption
- Program Goal: Resource Acquisition
- Storage does not need to ‘act’ in a specific way once installed at the customers site

+ Benefits

- Additional financial support to overcome the industry barrier of cost
- Could provide the incentive at different points in the supply chain including upstream, midstream or downstream to make the greatest impact

+ Drawbacks

- No persistent motivation to cause a customer to use the PV+storage technology in a way that best benefits the grid
- Current cost of technology may be too high to be able to develop an incentive program where the utility benefits are greater than the cost of the program

#### 6.3.1.2 *Monthly Utility Payment for Control of Storage*

+ Use case

- Market Maturity: Early Adoption/Early Majority
- Program Goal: Maximize grid benefits, utility control of / access to resource
- Customer owned PV+storage system with utility control of storage to maximize grid benefits

**+ Benefits**

- Utility uses the technology in a way that best benefits the grid
- Utility only paying for the value they will receive from controlling the battery which results in a cost effective program and reduced risk to the utility
- Utility maintains connection with customer (unless a third party is used to manage the storage operation)

**+ Drawbacks**

- Customer needs to be motivated to purchase PV and storage for other reasons
- Customer needs to overcome more of the cost barrier than with an equipment incentive
- Could be difficult to ensure the usage of the storage into the future unless there is a multi-year contract
- Utility needs a technical solution to manage the control of many batteries, or contract that management out to a third party

### 6.3.1.3 **Storage Electricity Rate**

**+ Use case**

- Market Maturity: Mature Market
- Program Goal: Market Saturation with Low Overhead
- Customer controlled PV+Storage regardless of ownership or financing of the system

**+ Benefits**

- Customer is motivated to use their PV+Storage to benefit the grid based on how the rate was developed to incentivize discharge at the times of day that are of greatest value
- Utility does not need to develop and administer a rebate report which saves cost

**+ Drawbacks**

- Rate development takes many years and the grid needs are likely to have changed by the time the rate is implemented
- Rate development is complex and requires input and approval from many parties and stakeholders
  - Note that an underlying ‘real-time’ rate structure could address these drawbacks

- Rate development requires a clear understanding of grid optimization techniques and the benefits of storage relative to the competing needs of the utility. This understanding is preliminary at this time.

### 6.3.2 EQUIPMENT OWNERSHIP MODELS

There are many options for equipment ownership that an integrated storage program can adopt which can be summarized into three main models: Customer-owned, Utility-owned, and Third-party-owned. The benefits and drawbacks of each model is described below from the view point of the utility.

#### 6.3.2.1 *Customer owned*

+ Utility Benefits

- No equipment cost to the utility
- Reduced risk to the utility for maintenance and operation
- Increased customer-utility relationship by providing utility financing

+ Utility Drawbacks

- Customer may withdraw from utility control program unexpectedly unless a type of contract is in place. This makes it harder for a utility to count on the storage device for deferral value
- Potential difficulty in integrating with multiple storage types
- Utility would not be able to include the equipment cost in their rate base
- High first cost for customer to overcome unless incentives are available
- Decrease customer-utility relationship if financing provided by third party

#### 6.3.2.2 *Utility Owned or Leased to the Customer*

+ Utility Benefits

- Utility may be able to include the equipment cost in their rate base
- Easier to maintain control of the storage device
- Increase customer-utility relationship by offering leasing option

+ Utility Drawbacks

- Responsibility to operate, control and maintain storage equipment

- Risk of customer frustration with the utility if something in the house breaks as the customer may blame the new storage device
- Increased costs for customer support and service to storage devices

#### 6.3.2.3 *Third Party Owned or Leased to the Customer*

##### + Utility Benefits

- Using a competitive solicitation would result in cost effective solutions by leveraging the market
- Reduction in administrative costs to implement and support an integrated program
- Third party responsible for ensuring customer participation
- Utility is not responsible for customer acquisition

##### + Utility Drawbacks

- Utility does not gain firsthand knowledge of working with integrated storage solutions during this early time in the market
- Not able to include equipment cost in rate base
- Removing of a potential touch point in the customer-utility relationship

## 6.4 Program Details

After collecting and determining program design considerations and program components there are a couple of final program details to consider to support the success of the integrated storage program design. Program marketing and development of a qualified products list are two primary topics on a list of many others that should be given careful consideration and research. This section only highlights those two specific topics as a starting point for program design discussions.

### 6.4.1 RESIDENTIAL MARKETING STRATEGY<sup>29</sup>

Outreach and marketing strategy should be a major component of any program. There are a couple of major marketing aspects to a residential program that should be considered, starting with developing a clear and

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<sup>29</sup> SMUD Interview

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simple message. This is key for all sectors but specifically the residential sector as energy is such a small part of the customers' daily concerns. The residential sector doesn't benefit from the attention and know-how of an assigned energy manager, as is common amongst other sectors. The value proposition should be simple and focus on why a customer would want the integrated storage solution, while including compelling monetary and non-monetary benefits. For residential customers focusing on benefits instead of drawbacks has been found to be more effective.<sup>30</sup> Another strategy is to develop a program name that is simple, specific and appealing to residential customers instead of a name that reflects energy or utility jargon. The residential sector has been found to be more emotional and focused on comfort and the personal impacts while the commercial sector is more driven by financial considerations<sup>31</sup>. Taking this into consideration, SMUD found that one-on-one outreach was more effective than rolling out a complex energy program. Utilizing a more grassroots approach and personal touch to explain the offering allowed the customer to feel that their concerns were addressed and that they understood the details of the new offering, such as dynamic prices. The marketing outreach should be tailored to the customer type that the program is targeting but these high level strategies can support the development of that framework.

#### 6.4.2 QUALIFIED PRODUCTS LIST

Regardless of whether the program design component is utility-owned with a specific technology or customer-owned with a variety of technologies, the program needs to consider what solution is qualified to participate in the program. This is of extra importance at this early phase of the storage industry because there has not been enough time to ensure the technology will last. Included below is a short list of characteristics to consider in a Qualified Products List with each factor deserving dedicated attention to ensure the product is the correct fit for the utility use case:

- + Round Trip Efficiency
- + Power Efficiency
- + Warranty
- + Interconnection requirements
- + Cyber Security solutions

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<sup>30</sup> SMUD Interview

<sup>31</sup> SMUD Interview

- + Communication(s) Protocol(s)
- + Utility access, control and remote monitoring
- + Eligible Smart Inverters
- + Capacity of battery or inverter
- + Safety Standards – UL 9540 is one option

## 6.5 Example Program Configurations

Using the program design considerations and components discussed earlier, three example integrated PV and storage program configurations are described below. The first example is a case study focused on the SMUD use case including the cost benefit analysis results discussed in Section 5. The second example involves a hypothetical utility and demonstrates the general process of using the framework of Sections 6.2 to 6.4 to drive toward a program design. The third and final example provides a unique alternative to an electricity storage rate for Smart Homes.

### 6.5.1 EXAMPLE PROGRAM #1: SMUD USE CASE

This CSI RD&D PV Integrated Storage research project provided a unique opportunity to model and determine actual financial impacts of residential behind-the-meter storage determined through modeling of an actual SMUD feeder. This modeling effort was able to provide estimated values to the various financial value streams (as listed in Section 6.2.1) that a utility might pursue in a program design. This section uses the program design framework established in Sections 6.2 to 6.4 as well as the modeling results from Section 5 to design a potential battery storage program for SMUD that uses empirical evidence from measured performance instead of hypothetical values.

#### 6.5.1.1 *SMUD Drivers*

The first step for developing an integrated storage program design is determining the utility's drivers. This is what will determine how success is defined for the program and what program components to focus on. The main SMUD drivers for this potential program design are listed below.

- + Customer Benefits
  - o Maintain relationship with customers as a trusted energy advisor

- Provide unique value to customers
- + Financial Benefits
  - Distribution deferral
  - Resource adequacy
  - Reduce energy costs through economic dispatch
- + Gain understanding and experience with storage before it becomes mainstream

#### 6.5.1.2 ***SMUD Concerns***

The next step in the program design framework is to evaluate what concerns the utility has with regards to behind-the-meter integrated storage. The program design should aim to minimize concerns if possible. The concerns associated with this SMUD use case are included below.

- + System impacts of storage – unexpected increases and decreases in load
- + Introduction of a third party relationship that interferes with utility customer relationship – third party managed resources
- + Costly upgrades needed to integrate with utility systems for transparency, monitoring and unit control – utility controlled systems

#### 6.5.1.3 ***SMUD Customer Drivers***

In the end, the program will need participation from customers to achieve its goals so it is important to understand the main customer drivers. Customer market research is an important way to gather detailed information on current customer drivers to tailor marketing efforts that increase participation in the proposed program.

- + Interest in new and ‘cool’ technology
- + Reduce electricity costs
- + Support integration of more renewables on the grid

#### 6.5.1.4 ***Storage Barriers Addressed in this Program***

If the market was already achieving the utility drivers and program goals, then there would not be a need for a program in the first place. Programs are used to overcome market barriers in order to achieve the established goals and drivers. Ideally a program could overcome all market barriers, but that is not realistic. Therefore, this proposed SMUD program chose to focus on addressing two specific storage market barriers: Cost and Interconnection Familiarity. The cost of the PV integrated storage technology was reduced by providing a monthly payment to the customer in exchange for utility control of the storage technology. The concern over interconnection delays was reduced through an expedited option for those PV+storage applications or storage applications adding onto PV systems.

#### 6.5.1.5 ***Program Description***

Following the provided program design framework, the SMUD use case supports a PV integrated storage program with monthly utility payment for the control of the storage with a customer equipment ownership model.

SMUD is able to provide a monthly payment to the customer because of the multiple value streams SMUD will realize which were described in Section 6.2.1. The largest value comes from the deferral amount which is dependent on where the storage is interconnected. The results showed very little additional value for storage on the Waterman-Grantline feeder as compared to the value PV was already providing. However, the Jackson Sunrise feeder showed significant value from adding a modest amount of behind-the-meter storage. This SMUD program will therefore focus on the customer locations on the Jackson Sunrise feeder.

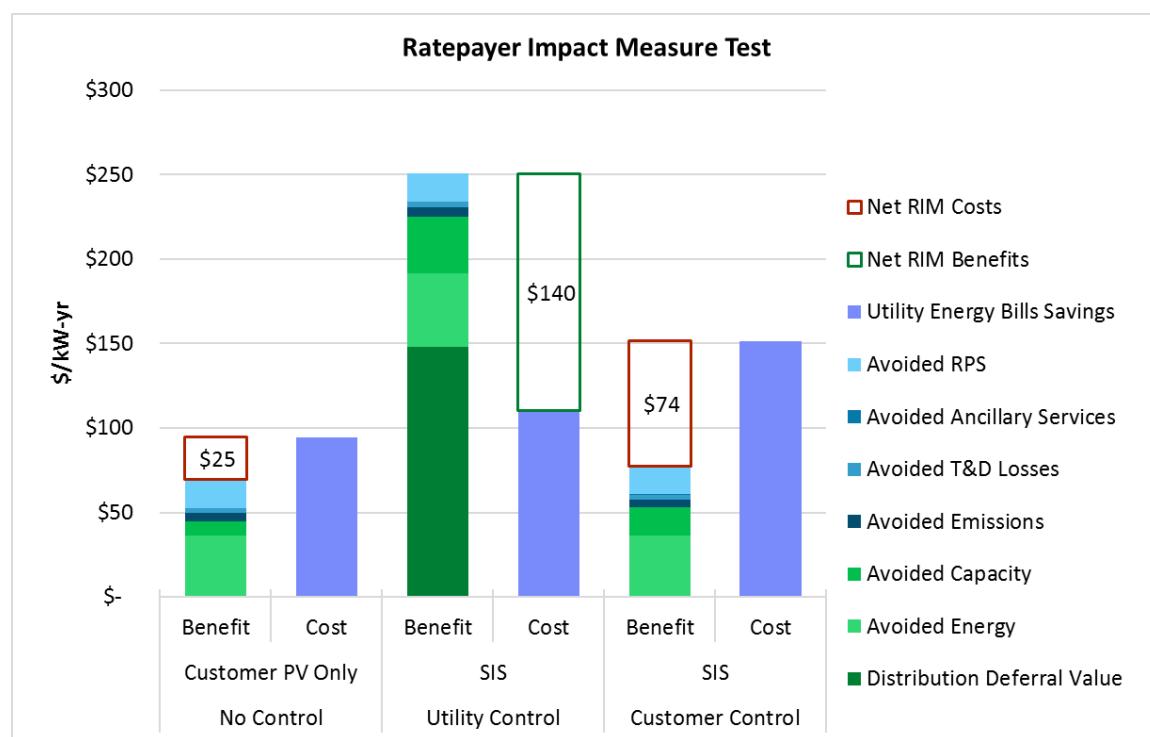
The Jackson-Sunrise feeder currently has 314 residential customers and 16 of those customers have PV interconnected with SMUD. The financial modeling in Section 5, determined that the use of 31 up to 36 storage units at the size of the Sunverge units modeled at 2500R (4.5 kW/unit) would result in the same realized value to the utility of \$227,149. This SMUD program would therefore target the utility control of 31-36 storage units that are combined with onsite PV.

To motivate the installation of PV+Storage systems on the Jackson-Sunrise feeder and address another industry barrier of interconnection process inefficiency, we recommend that the program also include measures to expedite interconnection of the PV + Storage projects, including the following:

- + Prioritizing PV + Storage applications at the front of the interconnection queue
- + Providing specific training for at least one local inspector on PV-integrated storage solutions
- + Coordinating with local AHJs on permitting and inspections
- + Standardizing and simplifying application docs and single-line diagrams for projects under 10kW

Modeling of the Jackson-Sunrise feeder determined that there is a value to the utility of \$251/kW-yr. With customer bill savings of \$110/kW-year., the utility would be able to offer the difference as a monthly incentive to the customer to grant the utility control over the storage device. Using the size of the Sunverge SIS units at the 2500R housing development as an average capacity (4.5 kW/unit) the program incentive would be \$140/kW-yr.  $\times$  4.5 kW/unit = \$630/unit a year, or \$52.5/month for PV+Storage. The customer would have the option to participate for up to 15 years with a minimum requirement of 8 years.

**Figure 6-1. RIM Test Results Excluding SGIP Incentives Under the TOU+CPP Rate (\$/kW-yr.).**



Based on financial modeling, current customers' bill savings are \$25/kW-yr. greater than the utility's benefits with PV-only on their site and when participating in the Time-Of-Use (TOU) rate combined with the CPP rate. This proposed SMUD program would start to even-out the PV equity issue among all SMUD customers.

Deferring capacity upgrades with non-wires solutions is still a relatively new demand management method for many utilities. Normally SMUD would schedule 12-18 months to construct a traditional upgrade project if the PV-storage alternative was not available. Also, SMUD would prefer to have 3-6 months of data covering the summer season to demonstrate the load reduction before deciding to defer the upgrades.<sup>32</sup> Therefore, this program would require that the customer commit to 8 years of allowing the utility to control their storage. This would provide the up to one year to achieve 3-6 months of summer data, the 12-18 month safety in case the PV-storage systems did not meet the design requirements, the 5 years the systems would be used for deferral, and 1 year of contingency to get at least 31 units enrolled in the program.

Using the data from the Jackson Sunrise feeder, a sensitivity analysis was completed on the value to the customer based on bill savings over the percent of battery reserved for back-up ranging from 45% to 85%. It was found that the difference in customer bill savings was less than \$5 dollars/kW-yr. Therefore, since the utility would own the battery and the impact to the customer is minimal, the program will include 100% utility control of the battery. The utility could guarantee no adverse bill impacts for the customer. Simplicity is a key to success in residential programs and this program design decision adds simplicity to the program instead of trying to partition out a certain percentage of the battery for utility control.

#### 6.5.1.6 *Benefits*

Following the program design framework resulted in a program that meets the main SMUD drivers and has many benefits for the utility including those listed below.

- + SMUD maintains relationship with customer
- + SMUD does not need to purchase and maintain storage units and PV systems
- + SMUD can gain experience with controlling customer owned batteries benefiting the grid
- + Program is locationally focused to harness greatest value out of storage
- + SMUD would not need to address the potential storage-to-inverter connection technology concern where new storage devices are not plug-n-play with existing inverters

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<sup>32</sup> SMUD Interview

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### 6.5.1.7 ***Drawbacks***

While the SMUD program has many benefits there are still risks and some drawbacks. Understanding these drawbacks are useful to understand if the SMUD program design is applicable to other utility situations.

- + SMUD needs to manage the charging of all the batteries
- + The program has to meet or exceed the program goal of 31 batteries in order to be cost effective.
- + SMUD cannot guarantee bill savings to the customer, particularly not over the savings available to the customer through self-managed onsite storage. This could impact customer satisfaction if not properly addressed.

## 6.5.2 EXAMPLE PROGRAM #2: MIDSTREAM APPROACH

The SMUD program example focused on the specific use case surrounding SMUD and the research documented in this paper. The program design framework discussed can be applied to a variety of other situations that are different than the SMUD case study. The following section provides a strawman midstream program design for a hypothetical utility titled Utility XYZ to demonstrate how the program design framework can be used.

### 6.5.2.1 ***Utility Drivers***

- + Provide unique value to customers
- + Support customers during a transition away from lucrative net-energy metering tariffs
- + Reduced energy costs through economic dispatch
- + Mitigate grid impacts of the projected evening ramp
- + Support integrated demand side management corporate strategy

### 6.5.2.2 ***Utility Concerns***

- + Costly infrastructure upgrades to allow for utility controlled DERs
- + Customer equity in distribution of infrastructure costs

### 6.5.2.3 ***Customer Drivers***

- + Supporting integration of more renewables on the grid

- + Investing in new and ‘cool’ technology

#### 6.5.2.4 ***Storage barriers addressed in this program***

- + Cost

#### 6.5.2.5 ***Program description***

The midstream integrated storage program design would provide an incentive to third party aggregation service providers for PV integrated storage residential behind-the-meter projects. The projects receiving an incentive would also agree to provide utility value through third party control based on utility provided price signals for a five-year period. Instead of a monthly payment, the program offers an equipment incentive at time of installation stipulating utility control for a five-year commitment. By providing a larger incentive up front the program tries to overcome the first cost barrier of PV integrated with storage equipment. Then that allows for the market to develop and in five years there will likely be more rate based or congestion relief programs that exist that the integrated storage solution could participate in to ensure sufficient ongoing revenue.

The midstream incentive location allows the third party to determine the best way to use the incentive. The third party can develop the best business case for their situation and potentially pass along the incentive to the customer or even use the incentive to set up a lease or financing option. This also allows the third party to decide if they would own the equipment or if the customer would own the equipment, again allowing the market to make the decision instead of a utility requirement. This plays a key role as the storage market continues to develop and determine the value proposition for residential storage solutions.

The midstream program for Utility XYZ would require that a third party handle the battery management and operation based on utility price signals. In this situation the utility would not have to develop the infrastructure as well as manage hundreds of storage assets. This program would be territory wide so would not be focusing on the deferral value of batteries but instead on economic dispatch which has been shown in this research project to not always fall within the designated ‘peak’ time periods. Also, having a third party manage the assets would allow for more creative ways to harness available capacity as long as the utility-third party interface allows for locational differentiation instead of just bulk system deployment. As the utility becomes more comfortable with non-wires distribution deferral they could experiment with sending high price signals for areas of high congestion to leverage their existing fleet of storage projects.

#### 6.5.2.6 ***Benefits***

- + Provide upfront incentive to begin to overcome the first cost hurdle and then let the market operate
  - o Potential for partnerships to form between storage, PV and financing vendors
  - o Consolidate solar sales channels and existing customers
- + Leverage existing market channels and business lines
- + Utility XYZ does not need to develop infrastructure and expertise to manage many small storage assets
- + Utility does not have to pick technology winner and can instead be vendor neutral
- + Performance accountability remains between utility and few aggregators, rather than utility and many customers
  - o Aggregator contract (rather than customer claw back) framework for ensuring ongoing performance
  - o Expected higher curtailment reliability from third-party aggregated resources

#### 6.5.2.7 ***Drawbacks***

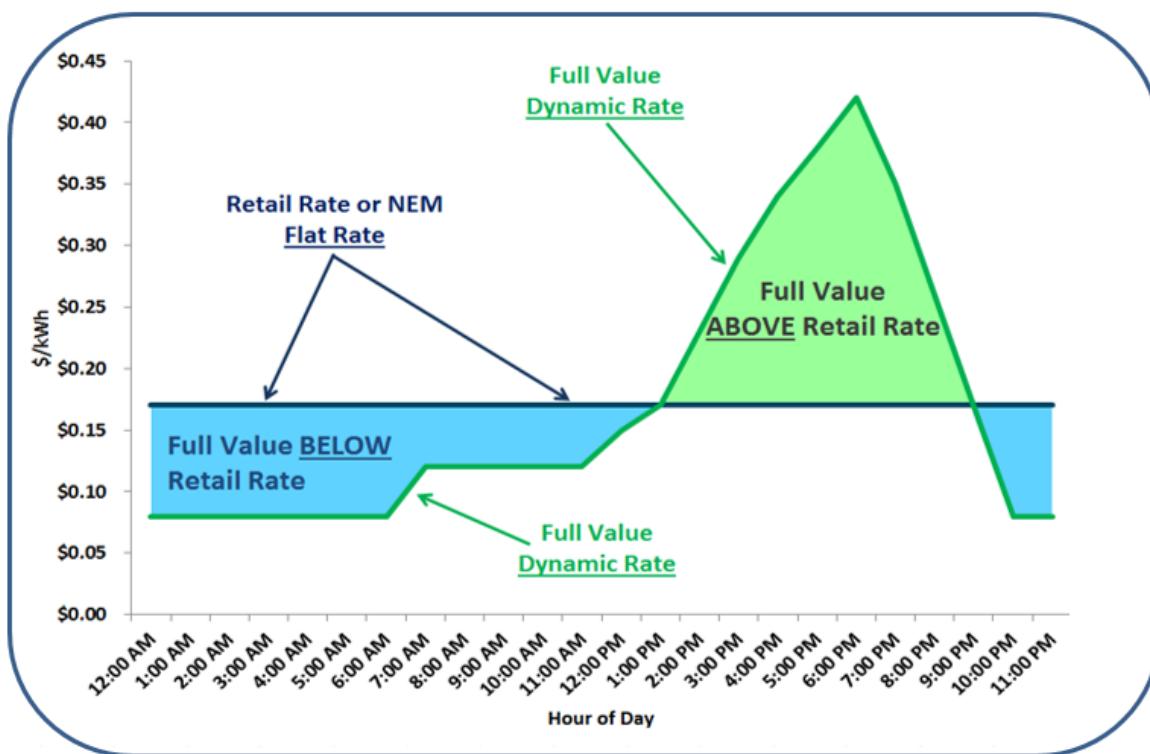
- + No direct tie between customer and utility incentive - utility loses a touch point with the customer to strengthen the utility-customer relationship
- + Incentive may not be large enough to move the market if the utility is held to traditional cost effectiveness requirements
- + No utility control over customer incentive/compensation for performance

### 6.5.3 EXAMPLE PROGRAM #3: FULL VALUE TARIFF

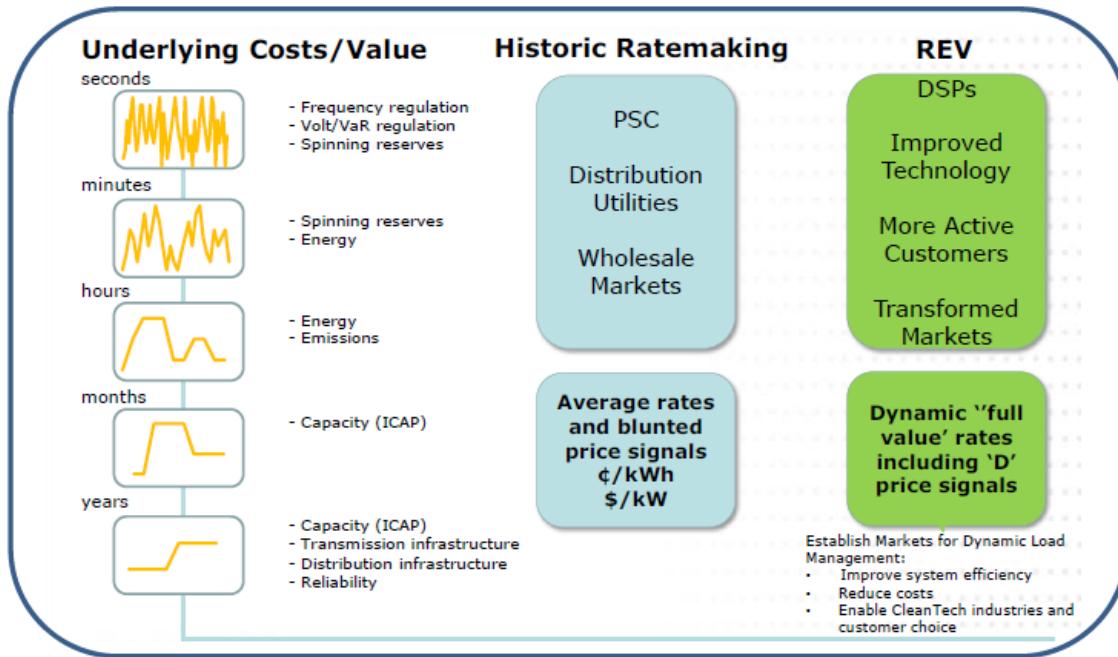
In contrast to following the program design framework, this section describes a unique rate-only integrated storage program design to animate the market and leverage third-party contributions in maintaining and managing the grid through the efficient investment in and operation of DERs. Traditionally, mass-market electricity retail rates have been relatively simple, averaging many of the costs of delivering reliable electricity into flat or tier-based volumetric rates. However, this simplicity artificially masks the temporal and spatial variation in the utility costs of reliably serving the electric load of its customers and limits the opportunities for DERs to participate in actively managing these costs in an economically efficient manner. E3's recent study

on behalf of several state agencies in New York as part of the Reforming Energy Vision (REV) proceeding proposes an innovative rate design called the Full Value Tariff (FVT) (Energy and Environmental Economics, 2016) that can put rate design and DER compensation on a more economically efficient and technology agnostic footing to encourage DERs and customer behavioral changes that can provide value in terms of both time and location as well as rationalize cost collection for the utility (Figure 6-2). Historic ratemaking has masked the true underlying costs of the grid from the customer. These costs now have the potential to become sources of value for DERs that can provide “full value,” which is something being contemplated in multiple jurisdictions, most notably in New York State through its Reforming the Energy Vision proceeding (Figure 6-3).

**Figure 6-2: A Full Value Tariff Provides Dynamic Price Signals than Traditional Flat or TOU Rates**



**Figure 6-3: The NY REV Full Value Tariff Reflects Underlying Costs Better than Historic Ratemaking Methods**



Communication networks, information technologies, and DERs enable customers to make better use of time- and location-specific price information than has previously been possible. A “smart” home may have a variety of internet-connected DER technologies such as lighting automation, smart thermostat, rooftop PV, energy storage, and/or a smart charging electric vehicle – some or all of which can respond to more granular and dynamic price signals, i.e. a Smart Home Rate, to lower costs and provide value for both the customer and the overall system.

A time-varying and location specific FVT can align the underlying costs of the electric grid on an hourly basis with the price and compensation signals sent to customers and DERs or DER aggregators. This incentivizes customers and DERs to maximize the value they provide to the utility without the necessity of the utility having direct control. In essence the market and load can respond to the price signals to assemble a portfolio of resources that can provide value to the grid without significant amounts of utility oversight, control, or investment. This could be one tool to use to manage costs and encourage adoption of high-value DERs.

The design goals of a FVT or Smart Home Rate can include the following:

- + Increasing the ability of non-utility resources to provide grid services

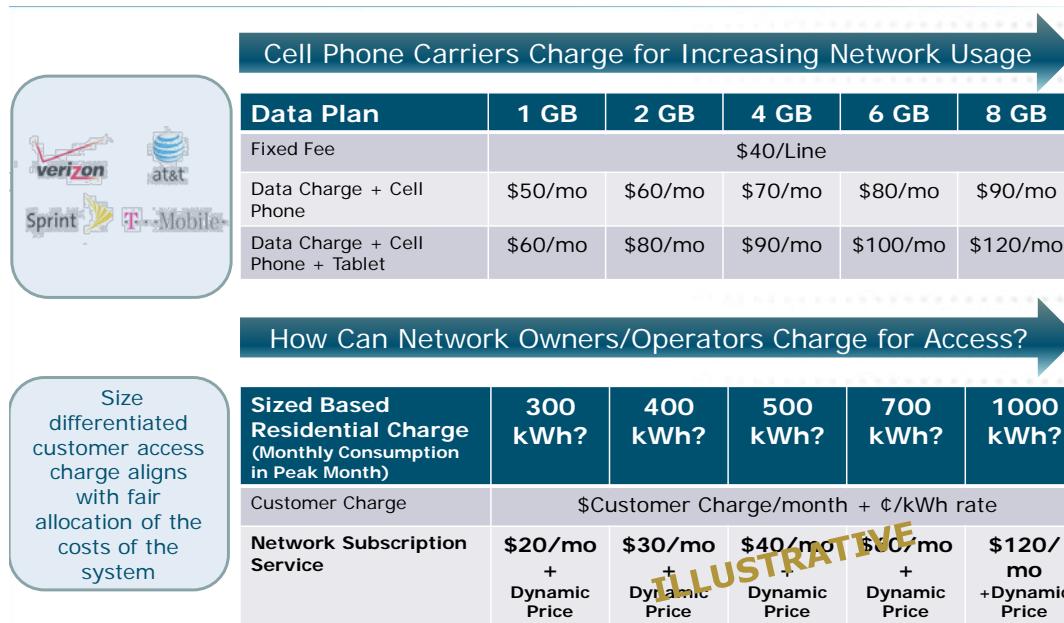
- + More accurately compensating customers and third parties for their contributions to managing the grid
- + Equitably and efficiently collecting embedded costs of the distribution utility
- + Lowering long term customer costs through more efficient usage of grid resources

#### 6.5.3.1 ***Full Value Tariff Characteristics***

A FVT should be constructed to reflect and recover both the marginal and embedded costs of the bulk electric and local transmission and distribution (T&D) system. Time varying energy prices should signal the forward-looking marginal value, i.e. avoided costs, of a change in consumption or production, while the total customer bills should collect the historical embedded costs.

Forward-looking marginal or avoidable costs are reflected in the FVT through time and location varying dynamic prices. Because marginal cost pricing of delivered energy does not account for prior utility investments or operations and maintenance, additional billing components are needed to allow the utility to collect the difference between their revenue requirements and revenues from pure marginal cost based hourly energy pricing. The FVT would provide customers with hourly prices that reflect the marginal cost of service and also allocate the embedded costs of the grid amongst customers based on customer connection size and grid use. Three components of a FVT rate include a Customer Charge, a Network Subscription Charge, and Dynamic Pricing. Figure 6-4 shows that consumers are already familiar with this rate structure, as it is commonly used by cell phone carriers to pay for different levels of access or subscription to the fixed cellular network.

**Figure 6-4: The proposed FVT is analogous to the rate structure used by cell phone carriers.**



- + **Customer Charge.** Embedded costs and expenses associated with serving the customer, such as the meter, meter servicing, and customer billing, are recovered through a charge on a (\$/customer) basis.
- + **Network Subscription Charge.** The embedded costs of the grid are inelastic and do not change dynamically with consumption or time of use. Embedded costs of grid infrastructure should be recovered based on the customer's size or share of peak demands. A Network Subscription Charge covers the cost of the existing grid infrastructure such as distribution, sub-transmission, transmission, and utility-owned generation assets. This charge could theoretically be created according to location specific grid asset utilization. One type of Network Subscription Charge is a demand charge (\$/kW). Demand charges are defined by a customer's share or usage during the peak demands on the various assets in the electrical network on a cost causation basis. It is important that the demand charge reflects the utility capacity planning and maintenance policies so that it reflects real world costs rather than a synthesized cost allocation. If demand metering is not available, then a monthly average demand charge (\$/kW-month) or monthly energy subscription charge (\$/kWh) may approximate this value. E3 in its FVT has proposed a Network Subscription Charge based on a rolling 12-month maximum monthly peak energy consumption or average demand in a peak month figure. A charge based on average demand or total consumption can provide an incentive for energy efficiency investments that lower average energy consumption.
- + **Dynamic Pricing.** The Dynamic Price is calculated using a location and time-varying price on electric energy (\$/kWh). The focus of the forward-looking marginal cost prices is to provide customers with clear price signals that allow the customers to make consumption and production decisions based on

actual marginal and avoidable cost impacts. Marginal and avoidable costs include locational marginal energy costs, electrical losses, avoidable T&D capacity costs, and avoidable generation, i.e. resource adequacy, capacity costs during peak periods. Avoidable T&D capacity costs reflects potential local network upgrade deferral value and would incentivize behaviors that can help reduce the need for planned distribution or sub-transmission upgrades. Marginal cost prices could also include adders for externalities or non-monetized societal costs such as carbon emissions.

#### 6.5.3.2 **Avoidable T&D Capacity Cost or Unlocking the Value of ‘D’**

A novel component of the Dynamic Price in the FVT proposal is translating the utility’s distribution and sub-transmission forward looking marginal costs into Dynamic Price signals, which is referred to as “Unlocking the Value of D”. This ‘D’ price signaling represents the avoidable distribution and sub-transmission capacity costs to incentivize DERs and consumer behavioral changes to act as an alternative to network upgrades, exposing these utility capital investments to competition and market forces. Under California’s Distribution Resource Planning (DRP) proceedings, utilities must consider DERs as an alternative when cost effective in comparison to planned sub-transmission or distribution network capacity upgrades. These values can form the basis of a forward-looking avoidable delivery capacity cost reflected in real-time energy prices.

Depending on the reaction of consumers and DERs to the real-time prices, the Dynamic Prices may need to be adjusted. For example, load reduction beyond what is necessary to avoid a network upgrade has no marginal value to the system, and so it should not receive compensation. Coordination of DERs and consumers through local market mechanisms, a DER aggregator, or other clearly defined operational rules will be needed to avoid unintended or inefficient reactions by DERs and consumers.

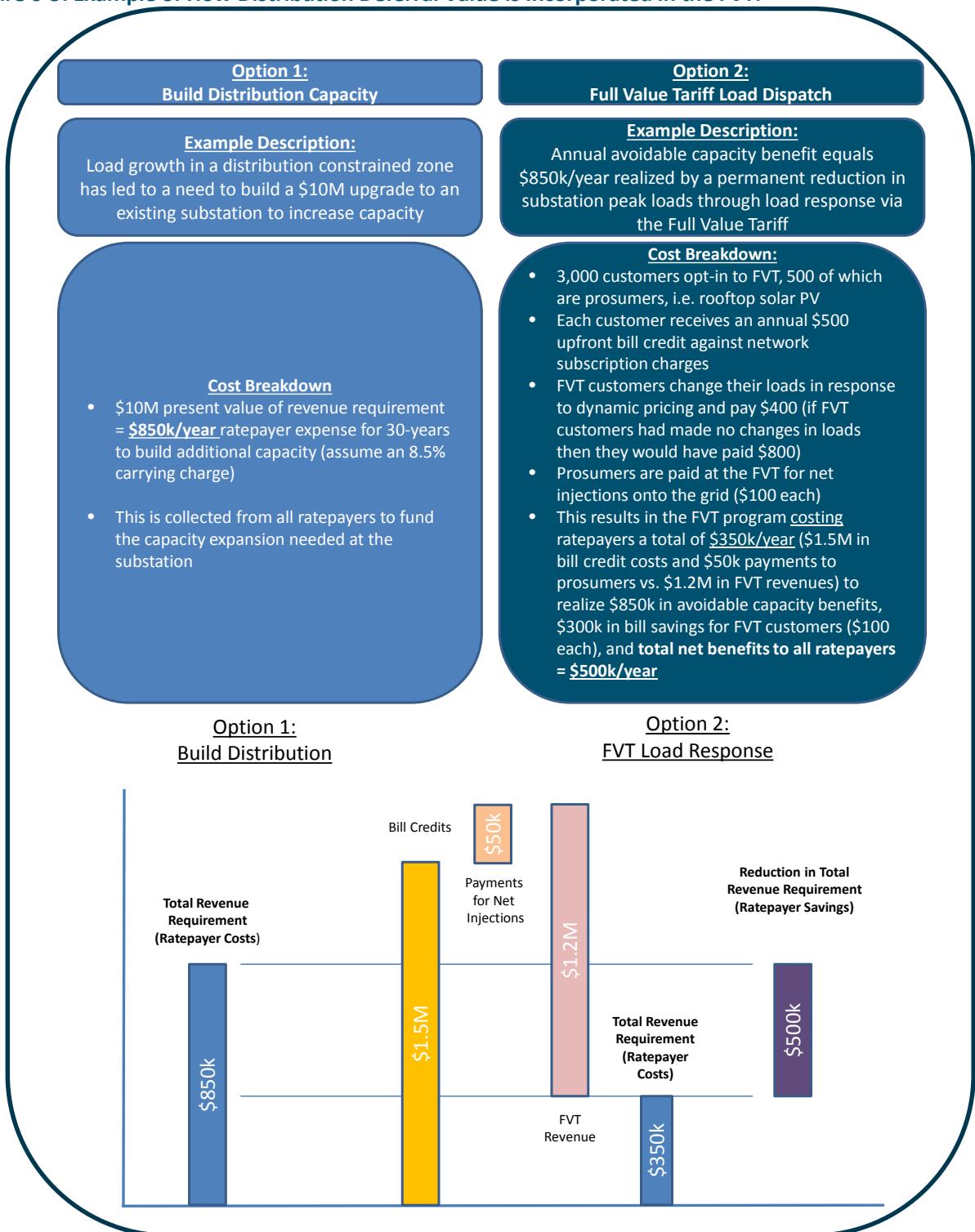
#### 6.5.3.3 **Billing Equity Issues**

The FVT is designed to enable customers to make efficient consumption and production decisions that would not cause cross-subsidization, uneconomic bypass, or welfare losses. In order to be viewed as fair by consumers and gain acceptance, a FVT should be designed avoid increasing the average customer’s bills, especially across locations. Customers should not be unduly penalized if they happen to be located in a T&D constrained portion of the grid. Any FVT formulation should be designed such that the participating customer population does not face a structural increase in customer energy bills if average customers do not change their behavior or adopt DERs, but rather gives flexible customers an opportunity to reduce bills by shifting load or providing net

injections into the grid at critical times. Yet, incentives for changes in customer and DER behavior must be balanced against the potential for cost shifting across customers and policy goals.

An example of how FVT driven dispatch of DER would compare to the cost and rate impacts of a tradition utility build of distribution infrastructure is shown in Figure 6-5.

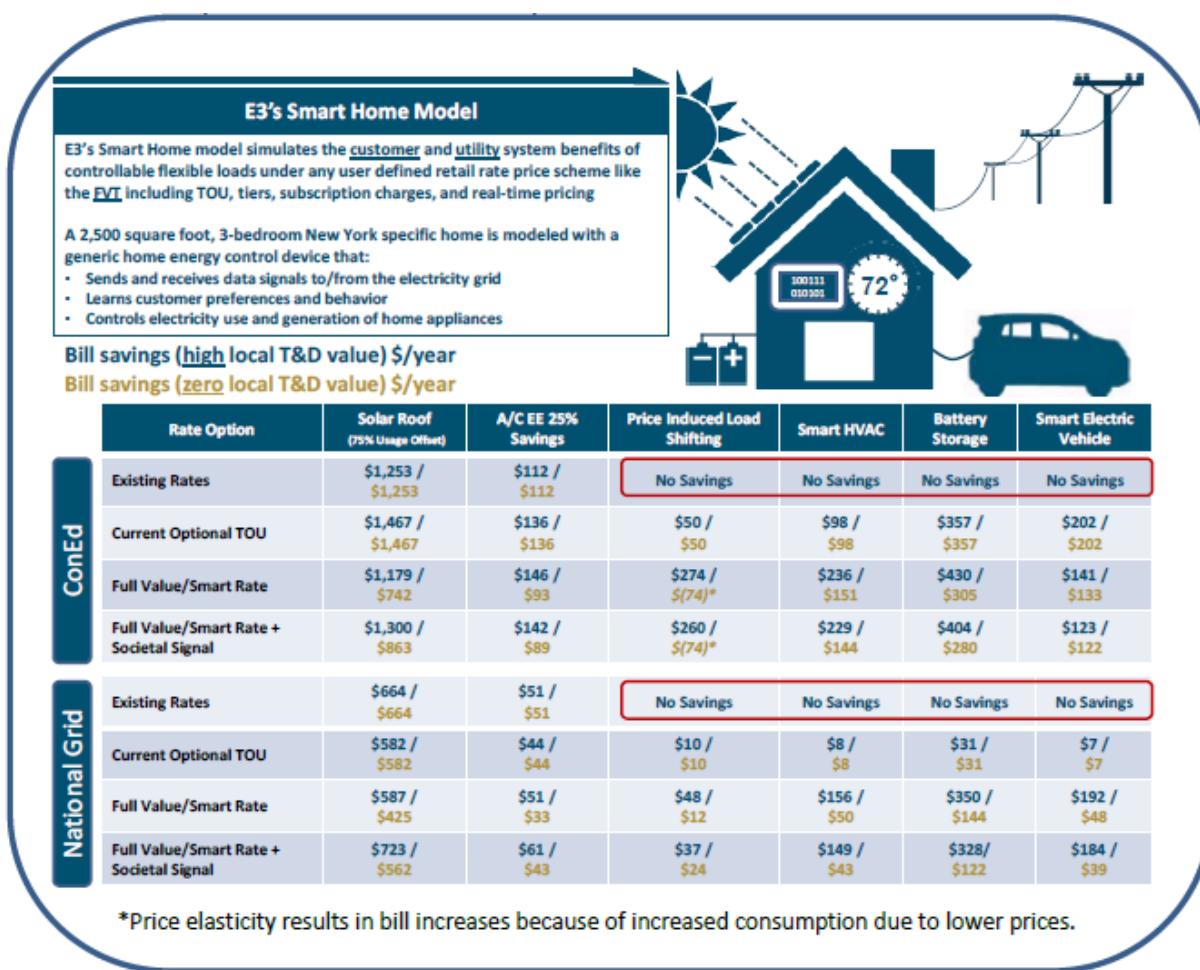
**Figure 6-5: Example of How Distribution Deferral Value is Incorporated in the FVT.**



#### 6.5.3.4 FVT Testing

As part of E3's FVT study a New York specific "smart home" model was developed to test various rate designs including FVT formulations with and without an explicit societal or externality adder. This model balances customer preferences with the potential for bill savings to see what the effects of a FVT would be on various technologies. As can be seen without a FVT like rate there is no customer value proposition for load shifting technologies like storage. 'Smart home' technologies can realize significant customer savings as prices become more value-based, i.e. time-variant and location-specific, under the FVT. Customer bill savings from both dynamic pricing and network subscription charge reductions from dispatchable and non-dispatchable technologies are shown for both a low and high local value location.

**Figure 1-4 Bill Comparison under Full Value Tariff in New York with Zero and High T&D Value**



# 7 Conclusions & Recommendations

The key conclusions and recommendations from our report are summarized below.

- + Sunverge successfully integrated SIS units with SMUD's demand response management system to automate DR events. The communication and subsequently, the functionality has limitations due to the communications protocol (OpenADR 2.0a), but can be overcome with the more robust OpenADR 2.0b protocol or direct communications with Sunverge's Control Software.
- + Only modest local distribution operational benefits are demonstrated for this case study. The results affirm findings from prior studies that operational benefits from DERs are highly location specific.
- + Under the assumptions modeled, PV plus storage as applied in this pilot project is not cost-effective under the TRC at near-term projected prices. Distributed storage can still be cost-effective in local capacity constrained areas or on distribution feeders with high deferral value.
- + We do find, however, that adding storage to PV can provide incremental benefits that exceed the cost of the storage system. Stated alternatively, the total cost of PV and storage exceed the TRC benefits, but the incremental TRC benefits of storage can exceed the cost of the storage system in some cases.
- + Combining customer and utility benefits is a promising business case for storage. The stack of benefits from the customer and utility perspective cannot simply be added together as some are mutually exclusive. Still, enabling utility dispatch (or providing dynamic rate signals) during certain high-value hours could combine the high value customer benefits (reliability and bill reduction) and utility benefits (local capacity and distribution deferral) in one application.
- + Storage that is dispatched on the customer's behalf to maximize bill savings does not provide benefits that exceed the loss of revenue to the utility under any scenario studied. The NEM cost-shift to non-participating ratepayers with storage is higher than with PV alone.
- + With utility dispatch or a dynamic Full Value Tariff, the benefits realized increase substantially relative to customer dispatch under a standard TOU or TOU-CPP rate. For the Jackson-Sunrise feeder in this case study, the total TRC benefits when storage is dispatched to meet both utility and customer objectives are up to 2.5 times higher when dispatched for customer benefit only under a TOU-CPP rate.
- + A CPP rate called based on system peak loads will result in load reductions that may not coincide with local distribution peak loads on many feeders.

- + The benefits of distributed storage are higher for feeders that peak later in the day after PV generation declines, and under higher penetrations of PV on the feeder, that push net load peaks to later in the day.
- + Allowing the utility to dispatch storage to charge from the grid in the morning on high load, low PV generation days would increase the reliable system and distribution peak load reductions more than when storage is limited to charge from PV alone.
- + A program including dispatch for utility as well as customer benefits or a dynamic Full Value Tariff is technically feasible and potentially attractive for customers. Furthermore, such a program provides significantly more value to the utility and its ratepayers than programs (such as California's Self Generation Incentive Program) that provide incentives for installing storage that is dispatched for the customer's benefit only.
- + A utility sponsored storage programs can be developed around three primary motivators: 1) utility drivers and concerns, 2) customer drivers and 3) storage industry barriers. The report describes program incentive and ownership options that can be designed around these primary motivators.

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# Appendix A. SIS Dispatch Optimization Model

In this section, we present the mathematical optimization problem that IDER uses to maximize the value of the SIS's battery under either customer dispatch or utility dispatch. The optimization problem from the utility's perspective is given in (1), with the arbitrage value and O&M cost at each hour defined in (2) and (3). The small  $m$  represents an arbitrarily small number that makes peak load reduction the first priority.

$$\max_{\substack{\text{Charge}_h, \text{Discharge}_h \\ \text{s.t. (4)-(12)}}} \left[ m \times \left( \sum_h \text{Arbitrage}_h - \text{O\&M\_Cost}_h \right) + \text{Peak Load Reduction} \right] \quad (1)$$

$$\text{Arbitrage}_h = (\text{Discharge}_h - \text{Charge}_h) \times \text{Total Avoided Cost of Energy}_h \quad (2)$$

$$\text{O\&M\_Cost}_h = \text{Variable O\&M} \times \text{Discharge}_h \quad (3)$$

The peak load reduction variable is constrained by (4)-(6) such that distribution network load is reduced to the upgrade threshold, and not more so, for the purpose of distribution upgrade deferral. Any further reduction in peak load would be because there is an incentive from the arbitrage value.

$$\text{Peak Load Reduction} \leq \text{Peak}_{\text{orig}} - \text{Peak}_{\text{new}} \quad (4)$$

$$\text{Peak Load Reduction} \leq \text{Peak}_{\text{orig}} - \text{Upgrade Threshold} \quad (5)$$

$$\text{Peak}_{\text{new}} \geq \text{Distribution Load}_h - \text{Discharge}_h - \text{PV}_h + \text{Charge}_h \quad (6)$$

Constraints (7)-(12) model the battery state of charge dynamics and limit the charging or discharging to the capabilities of the SIS unit's inverter. The parasitic load is 20 to 30 W which is necessary to power the SIS unit's computer.

$$\text{State of Charge}_h = \text{State of Charge}_{h-1} + \text{CD} - \text{Parasitic Load} \quad (7)$$

$$\text{CD} = (\text{Charge}_h \times \text{eff}_1) - (\text{Discharge}_h \div \text{eff}_1) \quad (8)$$

$$SOC_{min} < State\ of\ charge_h < SOC_{max} \quad (9)$$

$$0 \leq Charge_h - PV_h \leq Inverter_{max} \quad (10)$$

$$0 \leq Discharge_h + PV_h \leq Inverter_{max} \quad (11)$$

$$0 \leq Charge_h + Discharge_h \leq Inverter_{max} \quad (12)$$

When battery is dispatched to maximize customer benefits, the dispatch optimization problem is given by (13). In this problem, the arbitrage value is defined by (14) where the value of energy is given by the retail rate. Additionally, the battery is constrained by (15) to only charge from power produced by the SIS unit's PV array.

$$\begin{aligned} & \max_{\substack{Charge_h, Discharge_h \\ s.t. (7)-(12),(15)}} \left[ m \times \left( \sum_h Arbitrage_h - O\&M\_Cost_h \right) \right] \end{aligned} \quad (13)$$

$$Arbitrage_h = (Discharge_h - Charge_h) \times Rate_h \quad (14)$$

$$0 \leq Charge_h \leq PV_h \quad (15)$$

## CAPACITOR OPERATION SAVINGS CALCULATION

Capacitor replacement savings are estimated by the differences in the net present value of replacement costs with and without PV and SIS units due to the changes of capacitor lifetime. The impacts of PV and SIS are assumed to be 15 years, the lifetime of SIS units.

### *Capacitor Replacement Savings*

$$\begin{aligned} &= NPV\ of\ Capacitor\ Replacement\ Cost_{with\ DER} \\ &\quad - NPV\ of\ Capacitor\ Replacement\ Cost_{without\ DER} \end{aligned}$$

Where:

### *NPV of Capacitor Replacement Cost*

$$\begin{aligned} &= Capacitor\ Replacement\ Cost_{2016\$} \\ &\times \frac{(1 + inflation\ rate)^{Replacement\ year - 2016}}{(1 + discount\ rate)^{Replacement\ year - 2016}} \end{aligned}$$

And

$$\text{Replacement year}_{\text{without DER}} = \frac{\text{Capacitor Life Time (Hours)}}{\text{Capacitor Usage}_{\text{without DER}} (\text{Hours/year})}$$

$\text{Replacement year}_{\text{with DER}}$

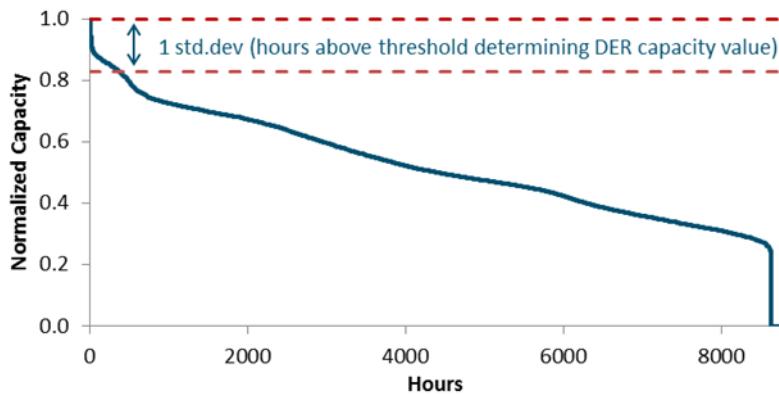
$$\begin{aligned} &= \min \left\{ \frac{\text{Capacitor Life Time (Hours)}}{\text{Capacitor Usage}_{\text{with DER}} (\text{Hours/year})}, \text{DER Life Time} \right. \\ &\quad \left. + \frac{\text{Capacitor Life Time (Hours)} - \text{Capacitor Usage}_{\text{with DER}} (\text{hours/year}) \times \text{DER Life time (yrs)}}{\text{Capacitor Usage}_{\text{without DER}} (\text{hours/year})} \right\} \end{aligned}$$

### PEAK CAPACITY ALLOCATION FACTOR (PCAF)

The peak capacity allocation factor (PCAF) method is used in two ways in the iDER analysis: 1) Allocating annual system generation capacity price (\$/kW) to each hour (\$/kWh) and 2) determining the contribution of DER measures toward distribution peak load reduction.

In this study, peak load hours are defined as the hours where network loads are within one standard deviation of the highest network load. Figure 8-1 illustrates how the threshold is determined and applied to the peak period.

**Figure 8-1. PCAF Hours on the Load Duration Curve**



The load in the hour below one standard deviation from the top of the load duration curve is the threshold cutoff and is the highest load not to be included in the peak period. Reducing loads in hours at or below the threshold is assumed not to have any capacity value to the system. The relative importance of each hour in reducing load is then quantified as a weighting factor. Weights are calculated for all peak hours in proportion

to their level above the threshold. The formula for PCAFs using proportional weights is shown below in (16), where  $Thresh[yr.]$  is the load in the threshold hour.

$$PCAF[yr][hr] = \frac{Max(0, Load[yr][hr] - Thresh[yr])}{\sum_{hr=1}^{8760} Max(0, Load[yr][hr] - Thresh[yr])} \quad (16)$$

Once the PCAFs have been determined for each hour of the year, these are multiplied by the annual generation capacity price (\$/kW) to determine the hourly capacity avoided cost of energy (\$/kWh). The application of the PCAF method to allocating distribution deferral value is discussed in section 5.3.2.2.

# Appendix B. Sunverge XML Documentation

## XML REQUEST (POST) AND RESPONSE WHEN THERE IS NO EVENT

### XML Request (POST) and Response when there is no event

#### Request

```
<?xml version="1.0" encoding="UTF-8" standalone="yes"?><ns3:oadrRequestEvent xmlns="http://docs.oasis-open.org/ns/energyinterop/201110/payloads" xmlns:ns2="http://docs.oasis-open.org/ns/energyinterop/201110" xmlns:ns3="http://openadr.org/oadr-2.0a/2012/07"><eiRequestEvent><ns2:venID>XXXXXXX</ns2:venID></eiRequestEvent></ns3:oadrRequestEvent>
```

#### Response

```
<?xml version="1.0" encoding="UTF-8" standalone="yes"?><ns6:oadrDistributeEvent xmlns="http://docs.oasis-open.org/ns/energyinterop/201110" xmlns:ns2="http://docs.oasis-open.org/ns/energyinterop/201110/payloads" xmlns:ns3="http://docs.oasis-open.org/ns/emix/2011/06" xmlns:ns4="urn:ietf:params:xml:ns:icalendar-2.0" xmlns:ns5="urn:ietf:params:xml:ns:icalendar-2.0:stream" xmlns:ns6="http://openadr.org/oadr-2.0a/2012/07"><eiResponse><responseCode>200</responseCode></eiResponse><ns2:requestID>reqId</ns2:requestID><vtnID>OPENADR2_VTN_ID</vtnID></ns6:oadrDistributeEvent>
```

### XML of an Actual Event Response to the request (POST)

```
<?xml version="1.0" encoding="UTF-8" standalone="yes"?><ns6:oadrDistributeEvent xmlns="http://docs.oasis-open.org/ns/energyinterop/201110" xmlns:ns2="http://docs.oasis-open.org/ns/energyinterop/201110/payloads" xmlns:ns3="http://docs.oasis-open.org/ns/emix/2011/06" xmlns:ns4="urn:ietf:params:xml:ns:icalendar-2.0" xmlns:ns5="urn:ietf:params:xml:ns:icalendar-2.0:stream" xmlns:ns6="http://openadr.org/oadr-2.0a/2012/07"><eiResponse><responseCode>200</responseCode></eiResponse><ns2:requestID>reqId</ns2:requestID><vtnID>OPENADR2_VTN_ID</vtnID><ns6:oadrEvent><eiEvent><eventDescriptor><eventID>533403E2-97B9-46B5-80E5-308AC3451CD8</eventID><modificationNumber>0</modificationNumber><eiMarketContext><ns3:marketContext>http://anymarket.com</ns3:marketContext></eiMarketContext><createdDateTime>2015-09-9T22:31:55.269Z</createdDateTime><eventStatus>far</eventStatus></eventDescriptor><eiActivePeriod><ns4:properties><ns4:dtstart><ns4:date-time>2015-09-10T23:00:00Z</ns4:date-time></ns4:dtstart><ns4:duration><ns4:duration>PT10799S</ns4:duration></ns4:duration><x-eiNotification><ns4:duration>PT10799S</ns4:duration></x-eiNotification></ns4:properties><ns4:components xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance" xmlns:xs="http://www.w3.org/2001/XMLSchema">
```

```

xsi:type="xs:string"></ns4:components></eiActivePeriod><eiEventSignals><eiEventSignal><ns5:intervals><interval><ns4:duration><ns4:duration>PT10799S</ns4:duration></ns4:duration><ns4:uid><ns4:text>0</ns4:text></ns4:uid><signalPayload><payloadFloat><value>1.0</value></payloadFloat></signalPayload></interval></ns5:intervals><signalName>simple</signalName><signalType>level</signalType><signalID>9FD7179D-26C7-4686-9BD3-7163286F0D32</signalID><currentValue><payloadFloat><value>0.0</value></payloadFloat></currentValue></eiEventSignal></eiEventSignals><eiTarget><venID>XXXXXXX</venID></eiTarget></eiEvent><ns6:oadrResponseRequired>always</ns6:oadrResponseRequired></ns6:oadrEvent></ns6:oadrDistributeEvent>

```

### Sample OpenADR Event Signal from SMUD (XML)

```

<ns6:oadrDistributeEvent
  xmlns="urn:ietf:params:xml:ns:icalendar-2.0"
  xmlns:ns2="urn:ietf:params:xml:ns:icalendar-2.0:stream"
  xmlns:ns3="http://docs.oasis-open.org/ns/energyinterop/201110"
  xmlns:ns4="http://docs.oasis-open.org/ns/energyinterop/201110/payments"
  xmlns:ns5="http://docs.oasis-open.org/ns/emix/2011/06"
  xmlns:ns6="http://openadr.org/oadr-2.0a/2012/07">
  <ns3:eiResponse>
    <ns3:responseCode>200</ns3:responseCode>
    <ns4:requestID></ns4:requestID>
  </ns3:eiResponse>
  <ns4:requestID>reqId</ns4:requestID>
  <ns3:vtnID>OPENADR2_VTN_ID</ns3:vtnID>
  <ns6:oadrEvent>
    <ns3:eiEvent>
      <ns3:eventDescriptor>
        <ns3:eventID>92C39C42-1FF5-4CBD-B4F5-579EDAEA2D5F</ns3:eventID>
        <ns3:modificationNumber>0</ns3:modificationNumber>
        <ns3:eiMarketContext>
          <ns5:marketContext>http://anymarket.com</ns5:marketContext>
        </ns3:eiMarketContext>
        <ns3:createdDateTime>2014-02-14T23:13:04.047Z</ns3:createdDateTime>
        <ns3:eventStatus>far</ns3:eventStatus>
      </ns3:eventDescriptor>
      <ns3:eiActivePeriod>
        <properties>
          <dtstart>
            <date-time>2014-02-15T00:00:00Z</date-time>
          </dtstart>
          <duration>
            <duration>PT3599S</duration>
          </duration>
          <ns3:x-eiNotification>
            <duration>PT3599S</duration>
          </ns3:x-eiNotification>
        </properties>
      </ns3:eiActivePeriod>
    </ns3:eiEvent>
  </ns6:oadrEvent>
</ns6:oadrDistributeEvent>

```

```
<components
    xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
    xmlns:xs="http://www.w3.org/2001/XMLSchema"
        xsi:type="xs:string">
    </components>
</ns3:eiActivePeriod>
<ns3:eiEventSignals>
    <ns3:eiEventSignal>
        <ns2:intervals>
            <ns3:interval>
                <duration>
                    <duration>PT3599S</duration>
                </duration>
                <uid>
                    <text>0</text>
                </uid>
                <ns3:signalPayload>
                    <ns3:payloadFloat>
                        <ns3:value>1.0</ns3:value>
                    </ns3:payloadFloat>
                </ns3:signalPayload>
            </ns3:interval>
        </ns2:intervals>
        <ns3:signalName>simple</ns3:signalName>
        <ns3:signalType>level</ns3:signalType>
        <ns3:signalID>359BB6F8-D6EE-42A0-BC6C-5DDBB2A6BE57</ns3:signalID>
        <ns3:currentValue>
            <ns3:payloadFloat>
                <ns3:value>0.0</ns3:value>
            </ns3:payloadFloat>
        </ns3:currentValue>
    </ns3:eiEventSignal>
</ns3:eiEventSignals>
<ns3:eiTarget>
    <ns3:venID>SEEloadIdentifierforVEN</ns3:venID>
</ns3:eiTarget>
</ns3:eiEvent>
    <ns6:oadrResponseRequired>always</ns6:oadrResponseRequired>
</ns6:oadrEvent>
</ns6:oadrDistributeEvent>
```

# Appendix C. Recruitment Letter

## RECRUITMENT LETTER TO 2500R COMMUNITY TO PARTICIPATE IN DRMS INTEGRATION TEST

Dear 2500 R Midtown Resident,

**Sunverge Energy is seeking volunteers to participate in a few short tests starting in October. As a token of our thanks, you will receive a \$100 Amazon gift card for volunteering to participate. Please respond by Friday, October 9<sup>th</sup> if you would like to participate.**

We want to test Sunverge's ability to automatically receive signals from SMUD and control the Solar Integration Systems (SIS). Our goal will be to limit your home's energy use from the grid and to send energy back to the grid during certain hours of the day. This project is part of a utility ratepayer-funded grant from the California Solar Initiative to validate renewable energy technologies.

Participants will allow Sunverge to send excess stored power from their SIS unit to the grid for several days during October and November. You will not experience any changes to your electricity habits, but there may be temporary changes to the operation of your SIS unit. We do not expect any impact to your electricity bill, because there is no special rate associated with this test. We are simply changing the time at which we send back your excess solar generation during test days. Sunverge will continue to reserve battery back-up power in the unlikely event of a grid outage.

Your participation will help us improve customer and utility services by improving the connection of Sunverge SIS units with SMUD's systems. Ultimately this will help ensure electricity reliability for all customers.

If you would like to sign up, please click on the following link to submit your contact information. Submissions must be made by Friday, October 9 to qualify.

We appreciate your support as we strive to enhance the value of your SIS and its operations. Remember, if you have any questions about the operation of your SIS, you can always contact our support team.

Best regards,  
Sunverge Programs team