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Via Electronic Filing

September 25, 2015

Mr. Steven V. King
Executive Director and Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive S.W.
Olympia, WA 98504-7250

RE: Comments on Docket UE-151069, Modeling Energy Storage in Integrated Resource Planning

Dear Mr. King:

Attached for filing in docket UE-151069 are the **Comments of the Interstate Renewable Energy Council, Inc. Responding to the UTC's Notice of Opportunity to Comment Issued August 7, 2015.**

Thank you for your assistance.

Sincerely,

Jason B. Keyes

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BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

Docket UE-151069

COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL, INC. RESPONDING TO THE UTC'S NOTICE OF OPPORTUNITY TO COMMENT ISSUED AUGUST 7, 2015

September 25, 2015

I. INTRODUCTION

The Interstate Renewable Energy Council, Inc. ("IREC") appreciates the opportunity to file these comments and the attached report in response to the Utilities and Transportation Commission's August 7, 2015 Notice of Opportunity to Submit Comments regarding modeling energy storage in integrated resource planning. IREC was not able to participate in the workshop in this docket held on August 25, but has reviewed the Staff White Paper.

As discussed below, IREC's focus is on the potential for customer-sited storage, and a proposed methodology for valuation of customer-sited storage coupled with solar energy. The Staff White Paper and the UTC's call for comments do not appear to contemplate this option, and IREC urges the Commission to consider it. Siting utility-controlled storage at customers' premises allows the significant benefit of back-up power for customers during utility outages, while providing all of the other benefits that centrally located storage can provide.

IREC is a 501(c)(3) non-partisan, non-profit organization working nationally to expand and simplify consumer access to reliable and affordable distributed clean energy by: (1) developing and advancing regulatory policy innovations; (2) generating and promoting national model rules, standards, and best practices; and (3) providing workforce training, education, and credentialing. IREC works independently from renewable energy industries, trade associations, technologies, and advocacy organizations; and, though we promote the creation of robust, competitive clean energy markets, IREC does not have a financial stake in those markets. Grounded in the latest research and objective analysis, IREC's work helps inform and guide fact-based regulatory decision-making and workforce development efforts. Through collaborative partnerships with diverse stakeholders, IREC seeks to build consensus and achieve workable solutions to create a sustainable and economically strong clean energy future. The scope of IREC's work includes expanding programs that facilitate consumers' ability to host a renewable energy system to directly self-supply energy needs or provide energy to the grid, and implementing shared renewable energy programs to expand options for consumers that cannot host a renewable energy system.

IREC looks forward to further participation in this docket.

II. Customer-Sited Energy Storage Has Inherent Advantages

Staff's White Paper provides a thorough overview of storage valuation, but does not appear to contemplate customer-sited storage. As well, the call for comments does not address the issue, though item A(3) asks for modeling of the benefit of "outage mitigation," which could include the value of back-up power. IREC suggests that customer-sited storage has the inherent added benefit of back-up power and can provide all of the other services that centralized storage can, and should be the first preference. In particular, customers with net metered solar arrays can add storage behind a single inverter, and have the potential for operation during extended outages.

In other jurisdictions, a utility preference for centralized storage has been premised on the notion that the utility can control energy storage facilities on their own property, but cannot rely on storage sited on customer property to be available when needed. This notion is incorrect – it is certainly possible to give the utility full control of customer-sited storage facilities, other than to let the customer rely on the stored energy during outages.

As one example, Sunverge installs utility-owned storage facilities at customers' sites, with hundreds of systems in place around the world. IREC suggests that storage facilities do not fall under the rubric of natural monopolies, and therefore is not promoting the Sunverge model, but the existence of Sunverge is proof that customer-sited storage can work. Instead, IREC suggests that customers can own storage facilities themselves, or lease them from third parties, as is done by customers do with solar arrays.

The advantages of customer-sited storage go beyond back-up power. First, the customer provides the site for the storage facility, relieving the utility from using or acquiring land for siting. Second, centralized storage entails line losses both delivering the energy to the facility and discharging the energy from the facility and delivering it to customers. And third, one hundred facilities capable of storing 10 kWh each (such as the Tesla Powerwall) totaling a megawatt are collectively more reliable than a single one MW storage facility. With a very high degree of confidence, at least 95 out of the one hundred small facilities will be operable at any given time, while the large facility can have a malfunction that results in no functionality.

III. Customers with Solar Facilities Are the Most Likely Early Adopters

Across the country, very few net metered solar facilities are coupled with storage, though it appears likely that will change over the coming decade. IREC does not have recent data from Washington, but several years ago, the state had a much higher percentage of net metered customers than in other parts of the country. Roughly, in Washington, over 5% of net metered customers also had batteries, while the figure nationally is below 1%. Presumably, this relates to the likelihood of outages in remote, wooded areas.

IREC is not aware of residential use of battery-only systems, though there are storage facilities for commercial customers as a means of controlling demand charges. Residential customers desiring back-up power almost universally rely on generators. In general, from conversations with companies that provide commercial storage, it appears that most systems are co-located with solar facilities, though controlling utility demand charges with storage is independent of use of solar facilities.

Solar customers are the most likely early adopters of energy storage for two reasons. First, they have the interest in self-generation that led them to install a solar array, making them the group most likely to consider related options. As has often been reported, customers tend to become more aware and interested in their energy consumption after installing a solar facility. And second, solar customers require an inverter, disconnects, wiring, and permit approvals already, making the addition of storage fairly simple. While an inverter capable of two-way power flows is required for storage facilities, which is a bit more expensive than an inverter for the output of a solar array, the cost of storage is lower for solar customers than for others.

IV. IREC's Solar Plus Storage Valuation Report

Attached to these comments is a report commissioned by IREC and conducted by Clean Power Research (CPR) to establish a valuation methodology for distributed solar coupled with storage, based on an assumption of utility control of the stored energy. The report focuses on Hawaii and gives preliminary value estimates for Hawaii that are not relevant to Washington, but the methodology is generally applicable. Hawaii has very high electricity rates, very high capacity costs, and experiences system peaks after sunset, making it attractive to install storage. For the purposes of demonstrating the application of the methodology, the report provides an example using the assumption that the utility will discharge the customer-sited energy storage on the 90 highest load periods of the year.

For Hawaii in the aforementioned sample run of the methodology, the report finds that energy storage adds 7.9 cents per kWh of energy generated by the solar array; that is, a solar plus storage facility costs more than a solar-only facility and actually produces less energy, after accounting for losses in energy storage. However, the report finds that the levelized value per kWh generated is 10.3 cents greater with the addition of storage than the value per kWh for solar-only facilities. For Hawaii, it appears that adding storage to a solar array adds a net 2.4 cents of value per kWh.

Realistically, storage is likely to cost as much in Washington as in Hawaii, but have less value in Washington. Still, energy storage costs are coming down and utility rates are likely to continue to rise, making storage a viable option for Washington in the future. To plan for that eventuality, IREC suggests that the Commission consider the methodology in the IREC/CPR report, and the general premise outlined in these comments regarding the advantages of customer-sited energy storage.

IV. CONCLUSION

IREC appreciates the opportunity to participate in the Commission's consideration of the role that energy storage can play in integrated resource planning, and looks forward to continued involvement in this docket.

Respectfully Submitted on September 25, 2015.

By: ______________________

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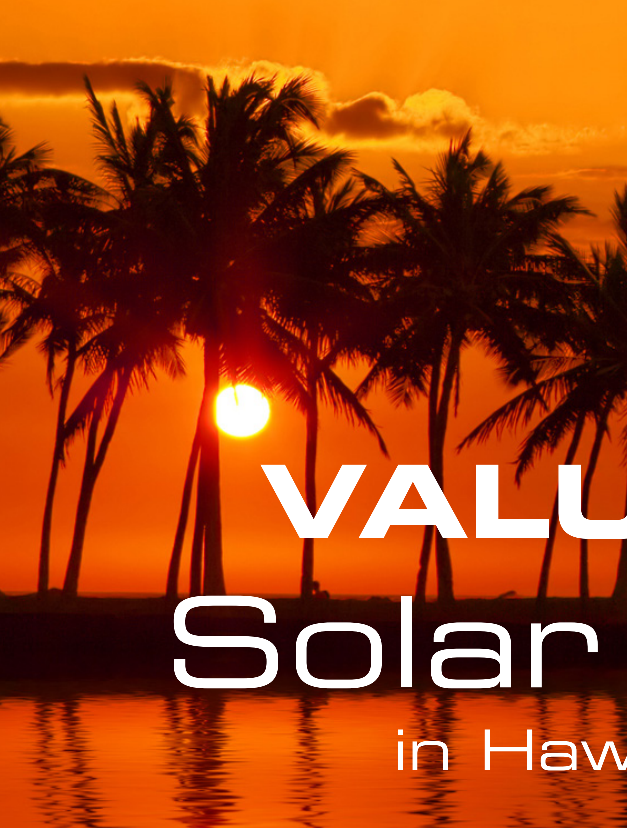
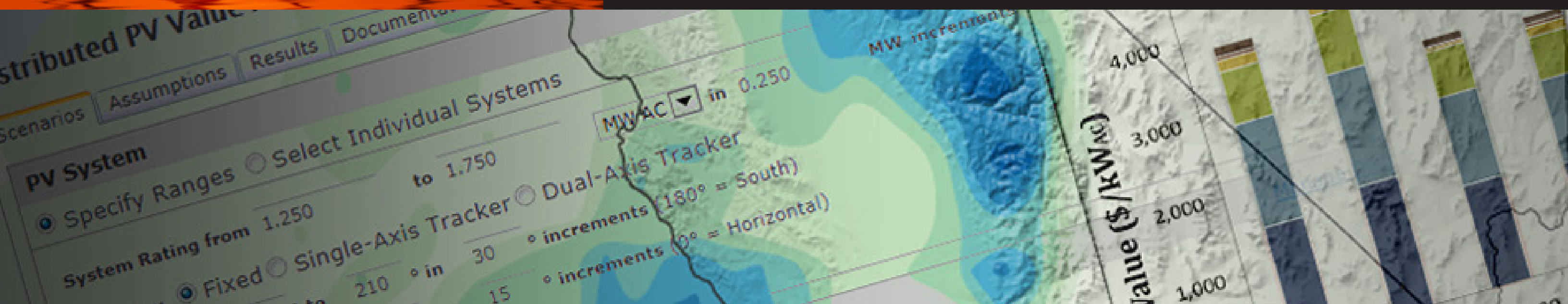
Attachment:

Valuation of Solar + Storage in Hawaii: Methodology



VALUATION OF Solar + Storage in Hawaii: Methodology



IREC Interstate Renewable Energy Council, Inc.

A REPORT of the
Interstate Renewable Energy Council, Inc.

by Ben Norris

Clean Power Research

June 2015

Legal Notice from Clean Power Research

Contents

Introduction

Background

The Interstate Renewable Energy Council, Inc. (IREC) engaged Clean Power Research (CPR) to develop a methodology that could be used to value solar energy coupled with battery storage in Hawaii. The methodology was to be largely driven by requirements in Hawaii, so as an initial step a workshop was held in Honolulu on January 23, 2015. The workshop included representatives from the solar community and the Hawaii State Energy Office who provided input and direction to the methodology. A meeting was also held with the Hawaii Public Utilities Commission staff which provided direction and insight into storage opportunities and challenges in the context of the state's electric grid requirements.

The desire to investigate storage and consider its use as an enabling technology in the islands is motivated by two observations.

First, the very high level of solar adoption there has led to concern by the utility that distribution transient over-voltages may exceed allowable limits and that backfeed on feeders may disrupt circuit protection. This has caused a backlog in interconnection approvals and a severe disruption in the solar industry, although recent NREL/SolarCity/HECO inverter studies have indicated that transient over-voltage concerns can be overcome through fast-tripping inverters.[1] Batteries could be charged using solar energy, thereby reducing or eliminating export onto the grid and overcoming the immediate interconnection bottleneck related to reverse power flow concerns.

Second, the generation capacity-related benefits of solar alone, as a non-dispatchable resource, are expected to be modest since the peak demand in Hawaii is found in the evening hours. Storage could be used to charge daytime solar energy for later dispatch during the peak after sundown. Thus, the combination of solar plus storage would increase both capacity and energy benefits.

Potential Benefit of Storage

A rough approximation of the potential benefit that would result from the addition of storage (over solar alone) may be made as follows. First, assume that the cost of capacity in Hawaii is $2000 per kW,[2]

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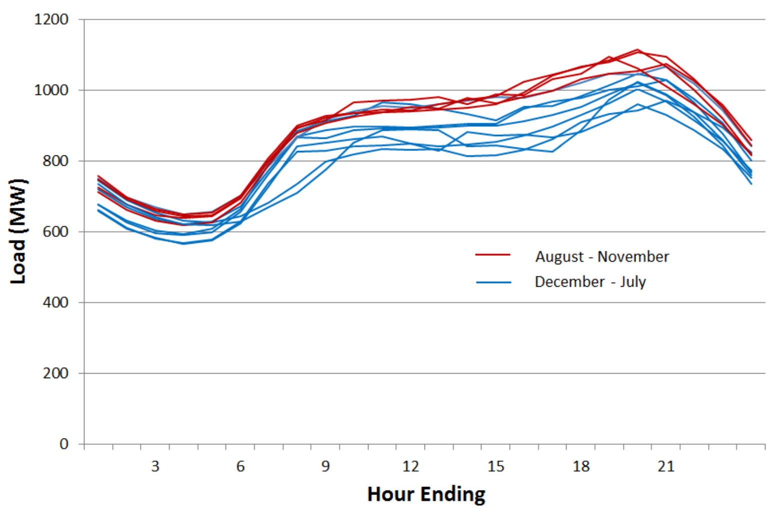
[1] "Inverter Load Rejection Over-Voltage Testing", A. Nelson, et al, National Renewable Energy Lab, February 2015

[2] Resource options are found in the Hawaiian Electric 2013 Integrated Resource Planning Report (http://www.hawaiianelectric.com/heco/Clean-Energy/Integrated-Resource-Planning). Behind-the-meter storage would probably be dispatched with approximately the same capacity factor (5%) as "simple cycle" (peaking) resources. The IRP (Appendix K) includes seven such commercial resource options, including biodiesel reciprocating engines, biodiesel gas turbines, and natural gas turbines. These range in capital cost from $1,997 to

and that new capacity is needed in the near term. Also, assume that a utility peak load reduction of 1 kW requires 2 kWh of storage capacity,[3] and that for simplicity the power rating of storage is equal to the power rating of PV (for every kW of PV resource, there is 1 kW / 2 kWh of storage).

Finally, assume that the desired peak load reduction is achieved by operating the battery in this way over the top 90 highest peak days, based on day-ahead forecasts, and not cycled significantly during the remaining nine months. While Hawaii does not exhibit seasonal variation as pronounced as many mainland utilities, Figure 1 indicates that the highest loads are clustered in the August to November timeframe. Thus, the assumption is that the top 90 days per year could be selected for battery dispatch.[4] The battery would not be dispatched on other days in order to preserve cycle life.

Figure 1. Oahu seasonal electric loads, taken on the 15th of each calendar month.



The capacity benefit in this scenario is calculated in Table 1, showing a study period of 25 years (typical assumption for PV life).[5] PV production of 1800 kWh per kW-AC (including losses) is based on a simulation for Honolulu using SolarAnywhere. PV capacity is assumed to degrade each year by 0.5%.

$6,633 per kW. The cost of $2,000 per kW is the lowest cost peaking resource option, and is therefore conservative.

[3] This could be dispatched, say, over a four hour peak period using a load-following algorithm. For example, if the load shape allowed storage to be discharged over four hours by ramping linearly from zero to full power over two hours, then ramping down to zero over the next two hours, then a 1 kW load reduction would require 2 kWh of storage.

[4] The figure is simplistic in that it utilizes data for only 12 sample days per year. A more detailed examination is warranted, requiring a larger dataset.

[5] Note that 90 cycles per year over 25 years results in 2250 cycles. This is roughly double the expected cycle life of lithium ion. This estimate assumes that batteries would be replaced by the customer as required. In the case of lithium ion, replacement would occur once in the middle of the 25 year period.

The amount of stored energy based on 90 days per year, and 2 kWh per day per kW of peak load reduction, or 90 x 2 = 180 kWh per year. Storage losses (assuming 20% of charging energy) are 45 kWh per year.[6] For each year, the non-stored energy is the available solar production, less the stored energy, less the storage losses. This is the energy that can be used to serve load directly (or be exported to the grid, as the case may be). The net generation, defined later in this report, is the sum of the non-stored and stored energy (assuming that there is no curtailment).

Finally, a levelized capacity value of $0.103 per kWh of net generation is calculated. This value is verified as follows. For each year, the levelized value is multiplied by the net generation to get the annual value. For example, in year 3, the annual value is $0.103 per kWh x 1,728 kWh = $178 per kW of PV/storage. This also represents a value of $178 per kW of peak load reduction to the utility in year 3. Next, this is discounted to net present value using an assumed utility discount rate of 8%, or $178/(1.08)^3 = $142 per kW. The sum of all years is the net present value of $2000 per kW.

In other words, a customer sited storage system, sized and dispatched as described above, could reduce the peak load by 1 kW per kW of battery power capacity. Based on the above estimate, the utility would be economically indifferent to (1) paying the customer for this peak reduction service a rate of $0.103 per kWh of net generation and (2) installing new peaking generation at a cost of $2000 per kW.

An estimate of the benefits of distributed solar alone (including energy benefit and other benefits) is not included here. But suppose the benefit of solar alone is $0.20 per kWh. Then the analysis above suggests that the net generation coming from the hybrid system would have a value of $0.20 + $0.103 = $0.303 per kWh.

A more comprehensive analysis is required using the methods described in this methodology report, including the use of actual utility system load and cost data, a model of hourly dispatch, and other factors rather than the simplified assumptions presented here. But this example does give a rough approximation, and it adds impetus to conduct a more in-depth study.

[6] Energy used to charge storage is 180 kWh / (1 – 20%) = 225 kWh. Losses are 225 – 180 = 45 kWh.

Table 1. Capacity Value Calculation.

Year	PV Production	Non-stored	Stored	Storage Losses	Net Generation	Levelized Value		
	kWh/kW	kWh/kW	kWh/kW	kWh/kW	kWh/kW	Lev. $/kWh	$/kW	Disc. $/kW
0	1,800	1,575	180	45	1,755	$0.103	$181	$181
1	1,791	1,566	180	45	1,746	$0.103	$180	$167
2	1,782	1,557	180	45	1,737	$0.103	$179	$154
3	1,773	1,548	180	45	1,728	$0.103	$178	$142
4	1,764	1,539	180	45	1,719	$0.103	$177	$130
5	1,755	1,530	180	45	1,710	$0.103	$176	$120
6	1,746	1,521	180	45	1,701	$0.103	$176	$111
7	1,737	1,512	180	45	1,692	$0.103	$175	$102
8	1,728	1,503	180	45	1,683	$0.103	$174	$94
9	1,719	1,494	180	45	1,674	$0.103	$173	$86
10	1,710	1,485	180	45	1,665	$0.103	$172	$80
11	1,701	1,476	180	45	1,656	$0.103	$171	$73
12	1,692	1,467	180	45	1,647	$0.103	$170	$67
13	1,683	1,458	180	45	1,638	$0.103	$169	$62
14	1,674	1,449	180	45	1,629	$0.103	$168	$57
15	1,665	1,440	180	45	1,620	$0.103	$167	$53
16	1,656	1,431	180	45	1,611	$0.103	$166	$49
17	1,647	1,422	180	45	1,602	$0.103	$165	$45
18	1,638	1,413	180	45	1,593	$0.103	$164	$41
19	1,629	1,404	180	45	1,584	$0.103	$163	$38
20	1,620	1,395	180	45	1,575	$0.103	$163	$35
21	1,611	1,386	180	45	1,566	$0.103	$162	$32
22	1,602	1,377	180	45	1,557	$0.103	$161	$30
23	1,593	1,368	180	45	1,548	$0.103	$160	$27
24	1,584	1,359	180	45	1,539	$0.103	$159	$25
								$2,000

Cost of Customer Storage

There is limited experience with customer-owned, grid connected storage, but it is possible to estimate costs using available market data. Tesla Motors recently announced[7] the availability of a residential

[7] http://www.teslamotors.com/presskit/teslaenergy. Tesla indicates that the cost for a 2 kW / 10 kWh battery is $3,500 and the cost for a 2 kW / 7 kWh battery is $3,000. The SolarCity installed cost included here is for the 10 kWh battery.

lithium-ion battery product, and based on this product, SolarCity indicated[8] an installed cost (pre-inverter) of $500 per kWh.[9] This is in line with the low end estimate from a Purdue University study[10] which estimates the capital costs of lithium ion battery energy storage systems[11] for time-shift applications (2 – 4 hours) to be in the range of $500 - $1500 per kWh for energy.

Inverter costs would be in addition to these amounts, and the Purdue study indicated $400 - $1000 per kW for power. However, in a combined solar/storage hybrid design, it would be possible to configure the system such that the solar array and storage element share a common inverter (connecting to the same DC buss. Such a configuration would require that the inverter that operates bi-directionally (both "inverting" and "rectifying," i.e., discharging and charging), unlike conventional inverters that only operate in the forward DC-to-AC direction. In addition, the inverter would have to allow an additional connection port on the DC side. Both of these modifications are simple. Provided that the total kW power rating of the inverter does not change, the incremental cost for battery support should not be significant. Therefore, the low end of the Purdue estimate of $400 per kW is used here.

Therefore the lower bound of both inverter power ($400 per kW) and energy ($500 per kWh) are taken as the cost estimate, for a total of $400 per kW + $500 per kWh x 2 kWh per kW = $1400 per kW. As shown in Table 2, the incremental cost of this storage would be about $0.079 per kWh,[12] taking into account the incremental capital cost and the incremental losses.

Table 2. Incremental Storage Costs (8% Discount Rate)

	Capital Cost	First Year Net Energy	25-yr Levelized Cost ($/kWh)
Solar Only	$5,200 per kW-AC ($4,000 per kW-DC)	1,800 kWh	$0.261
Solar+Storage	$6,600 per kW-AC	1,755 kWh	$0.340
Incremental cost of storage	**$1,400 per kW-AC**	**45 kWh (losses)**	**$0.079**

8 http://www.greentechmedia.com/articles/read/solarcitys-plan-for-tesla-batteries-share-grid-revenues-with-homeowners?utm_source=Solar&utm_medium=Picture&utm_campaign=GTMDaily
9 $5,000 for the 10 kWh option.
10 See page 43 of http://www.purdue.edu/discoverypark/energy/assets/pdfs/SUFG/publications/SUFG%20Energy%20Storage%20Report.pdf
11 Battery energy storage system costs include batteries, bi-directional power conditioning, and balance of system (BOS) such as charge controls and auxiliaries.
12 The levelized cost of storage alone based on the energy discharged alone (180 kWh per kW per year) would be about $0.68 per kWh.

With levelized costs less than levelized benefits—$0.079 versus $0.103—the added capital cost of storage may be expected to pay for itself, provided that the capacity benefit is monetized for the customer. Expressed in capacity terms, the incremental storage cost is $1400 per kW compared to the utility cost of capacity of $2,000 per kW.

There are several reasons to believe that the customer economics may even be more attractive:

- Downward Cost Trends. We know that the costs of lithium ion technology are dropping significantly[13] due to the increase in production and sales of electric vehicles based on lithium ion battery packs. Inverter costs are also decreasing. The electronics costs may also be partly tied to electric vehicle sales,[14] so with volumes increasing in this related market the power-related costs would decline.

- Discount Rate. This calculation assumed an 8% discount rate for both the utility capacity costs and the storage costs. In actuality, the customer discount rate may be less (e.g., home equity loans). At a discount rate of 5%, for example, the levelized cost of storage decreases to $0.057 per kWh of net generation

- Combined PV/Storage Power Conversion. The costs assumed above include the power electronics component (to charge and discharge between AC and DC). However, systems could be designed to serve as both PV inverters and charge controllers. While the cost of a combined bi-directional power conditioning system may be higher than a PV inverter alone, the incremental cost would certainly be less than a stand-alone system dedicated the storage component in addition to the PV inverter.

- Time-Flexible Loads. Lithium Ion technology is not the only option for energy storage. The cost of "time-flexible loads," described briefly in this document, would be less. These may prove to be an attractive approach that could be used to supplement batteries at a lower total cost.

These preliminary results suggest that, in Hawaii under a non-export policy, the incremental cost to the customer of energy storage may be less than the capacity benefit it provides.

Solar-Only Studies

While a number of solar energy valuation studies have been performed over the years by CPR and others, the technical calculation details were often not emphasized, and in some cases it has been difficult for the public to know exactly how the calculations were performed. However, two recent

[13] Tesla Motors is expecting a decrease in battery pack costs of 35% from 2013 to 2017. See http://www.teslamotors.com/sites/default/files/blog_attachments/gigafactory.pdf
[14] For example, power transistors are used for both EV charging and stationery power conditioning systems.

methodologies developed by CPR were designed for the purpose of public use, with the intent of providing sufficient detail to allow different analysts, given the same input data, to arrive at exactly the same result. Transparency and repeatability were key objectives in these studies.

For these reasons, these two methodologies are included here for reference as they are relevant to this document. The first methodology was developed under a public, stakeholder-driven process in April 2014 for the Minnesota Department of Commerce.[15] This methodology included a set of technical steps, such as simulating fleets of distributed PV resources and calculating loss savings, as well as methods to determine avoided costs and calculate a long term value in terms of dollars per kWh of energy generated by PV. This was the first such public methodology, and it was later adopted by the Minnesota Public Utilities Commission.

A similar methodology was prepared in March 2015 for the Maine Public Utilities Commission.[16] The Maine methodology, also developed with significant stakeholder review, was primarily differentiated from the Minnesota work by the use of market pricing for energy, generation capacity, and regional transmission (markets managed by the New England Independent System Operator). It also included additional societal benefits: the net social cost of SO_2 and NO_x and market price reduction.

As the methodology for Hawaii is built upon the work in Minnesota and Maine, this document focuses on the unique aspects of the storage addition, and incorporates these two solar-only methodologies by reference.

Storage-Only Studies

There have also been studies performed on the basis of grid-connected, stationary storage resources, without solar. Sandia[17] evaluated possible use scenarios, for example, in order to identify the types of benefits that may result from energy storage, such as electric energy time shifting, electric supply capacity, load following, frequency regulation, T&D deferral, power quality, and others.

These benefits are largely dependent on the specific use case. They cannot always be combined for multiple benefits. This is because at a given time the control algorithm of one use case may be in conflict with another. For example, you cannot both reserve stored energy for reserve power and spend storage energy for load following at the same time.

Another factor governing use cases is ownership and control. Generally speaking, customer use cases require customer control, and utility use cases require utility control. There may be exceptions to this

[15] http://mn.gov/commerce/energy/businesses/energy-leg-initiatives/value-of-solar-tariff-methodology%20.jsp
[16] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2014-00171
[17] http://www.sandia.gov/ess/publications/SAND2010-0815.pdf

rule that emerge (similar to some demand response programs). However, this methodology presumes that the equipment is customer sited and therefore customer controlled.

Two of the Sandia use cases are considered here: “electric energy time shift” and “electric supply capacity.” These use cases are incorporated into the methodology using the same evaluation methods as the solar-only studies, but using the net generation profile shapes (solar plus storage) described in this report.

Valuation Framework

The solar plus storage valuation methodology developed here is intended to estimate the value, i.e., the net benefits minus costs, that accrue to the utility and its customers from grid connected, behind-the-meter, distributed hybrid solar/storage resources. The perspective of the customer utilizing such a hybrid system is not addressed, so cost-effectiveness tests such a payback and internal rate of return are not part of this methodology.

Technical Evaluation

Fleets versus Systems

The Minnesota and Maine methodologies include methods for evaluating a fleet of PV resources. The rationale for this is that every system will have unique characteristics of (1) latitude/longitude coordinates, and (2) orientation (tilt and azimuth angles). The value is therefore based on a blend of anticipated locations and orientations. Storage adds two additional dimensions to the mix: the size of storage in power (kW) and energy (kWh, or simply “hours”) relative to the nominal size of PV.

There are two approaches to address this problem. First, one or more “typical” systems may be defined and evaluated. This is covered more fully in the Study Scenarios section. Second, a fleet of hybrid systems may be defined and evaluated. Like the solar-only studies, this fleet may be based on a representative blend of systems, rather than actual systems. Furthermore, the dispatch could be based on representative customer load shapes, such as those defined by customers in a given rate class or customers on a particular rate schedule.

Net Generation Profile

For the solar-only studies, the generation profile, i.e., the hourly energy output of solar that provides the benefits and costs to be evaluated, is based on a deterministic modeling process. In the case of hybrid systems, however, the hourly charge and discharge profile of the storage component is user-defined. The output of these systems depends on how they are operated.

To address this issue, four basic algorithms are described in this methodology (see "Dispatch Models"). The algorithms define a charge/discharge pattern based on one of four possible objectives:

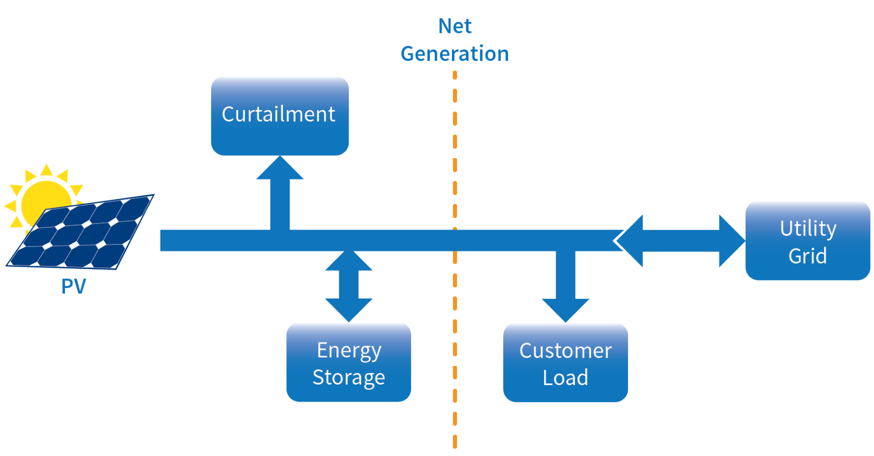
- Maximize value to the utility
- Maximize value to the customer/owner (time-of-use rate schedule)
- Maximize value to the customer/owner (demand schedule)
- Maximize value to the customer/owner (standard schedule)

Whereas solar-only evaluation is based on energy generated by a photovoltaic (PV) system measured by the output of the inverter, the hybrid evaluation must consider additional factors. The energy to be valued is the net increase or decrease in energy that would be delivered by the utility as a result of the hybrid system behavior.

As illustrated in Figure 2, this "net generation" is the combined, net result of (1) PV generation, (2) battery charging or discharging, and (3) curtailment. Curtailment may be required if export energy is prohibited. In this case, the amount of curtailment necessary would be based on real-time load, available PV power, and the SOC of the battery.

Net generation may be either positive or negative. For example, in a given hour, the net generation may be made up of PV production minus battery charging, minus curtailment. In another hour it might be made up of PV production plus batter discharge, without any curtailment. In another hour it may be made up of only battery charging from the grid (no PV or curtailment).

Figure 2. Definition of Net Generation for Valuation Purposes



It is important to note that net generation is not the same as export energy and it would require at least one separate meter to measure it (if desired). Note also that curtailment would probably not be directly measureable because it would most likely be accomplished by reducing the PV power passing through inverter from its maximum level to a reduced level. In the simplest arrangement, net generation could be measured using a single meter combining the PV and battery on a single circuit (or on the DC bus of the inverter).

Other Technical Factors

Once the net generation time series data is developed, the calculations of effective load carrying capability (ELCC), peak load reduction (PLR), and loss savings factors for energy, ELCC and distribution would all be computed using the methods described for Minnesota/Maine.

Economic Value

Benefit/Cost Components

In a stakeholder-driven process, much of the input concerns the selection of benefit/cost components. Energy supply components (fuel and generation capacity) are widely accepted because they are utility avoided costs.[18] Transmission and distribution avoided capital costs are also generally accepted, but the methodologies are less established and accepted.

In general, it is more difficult to obtain consensus on the inclusion or exclusion of environmental components and other societal values. This is partly due to the fact that they are not utility avoided costs (i.e., they are not expenses incurred by the utility or collected in rates) and partly because the methodologies rely on more speculative assumptions.

With these caveats, a proposed strawman of benefit categories are included in Figure 3, along with an overview of the computation of those categories. A full study would benefit from including a review of the relevance of these components, as CPR has done in its prior solar-only studies.

[18] There is usually stakeholder input related to the specific methods used for energy and capacity valuation, but not whether the categories should be included.

Figure 3. Example Benefit and Cost Calculation

		Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distributed PV Value D ($/kWh)
Energy Supply	Avoided Fuel Cost	C1				LSF-Energy		V1
	Avoided Gen. Capacity Cost	C2		ELCC		LSF-ELCC		V2
	Avoided Res. Gen. Capacity Cost	C3		ELCC		LSF-ELCC		V3
	Frequency Regulation	C4		ELCC		LSF-ELCC		V4
	(Solar Integration Cost)	(C5)				LSF-Energy		(V5)
Transmission & Distribution	Avoided Trans. Capacity Cost	C6		ELCC		LSF-ELCC		V6
	Avoided Dist. Capacity Cost	C7		PLR		LSF-Dist		V7
	Voltage Regulation	C8						V8
Environmental	Social Cost of Carbon	C9				LSF-Energy		V9
	Social Cost of SO_2	C10				LSF-Energy		V10
	Social Cost of NO_x	C11				LSF-Energy		V11
Other	Marginal Cost Response	C12				LSF-Energy		V12
	Avoided Fuel Price Uncertainty	C13				LSF-Energy		V13
								Total

A few observations may be made related to the methodologies as they relate to the addition of storage. These are detailed below.

Avoided Fuel Cost and Fuel Price Uncertainty

In the solar-only methodologies, natural gas has been assumed as the displaced fuel. In Hawaii, oil-fired generation is predominant, so adjustments would have to be made accordingly. Futures for fuel oil would be used instead of natural gas, and transportation to the islands would be factored in.

Generation Capacity Cost

The methodology would be the same as Minnesota, with two differences.

- For Minnesota, a blend of natural gas simple cycle turbines and combined cycle turbines were used. The cost basis for Hawaii would have to correspond to the technology anticipated by HECO for the next capacity addition. For example, if diesel plants were used, then the costs should be taken for diesel.
- The costs should be discounted if the expected capacity is to be installed in some future year.

Frequency Regulation

This benefit has not been included in solar-only studies. Storage has the ability to charge and discharge in response to signals from the grid operator in order to help regulate frequency. However, it would not be able to provide this service during the system peak without increasing power rating. For example, if the system were discharged at its rated power capacity to support the system peak, it could not also provide additional power that would be required to support frequency.

Considerations such as benefits of frequency regulation for only selected hours, telemetry requirements for small, residential systems, and the combination of multiple storage use cases require additional study.

Avoided Distribution Capacity Cost

This category may be problematic for Hawaii because HECO is facing the possibility of cost increases in order to support solar in the distribution system. On the one hand, planned distribution upgrades to allow backfeed may be considered the baseline case, so onboarding solar would not add costs beyond this plan. On the other hand, these costs are attributed to solar, so they may be considered a cost. This question requires further evaluation.

Environmental Costs

In the case that storage charging from the grid is considered (see "Dispatch Models"), the loss in efficiency from storage may increase environmental costs through off-peak charging. The net effect of the benefit from on-peak environmental benefit and off-peak environmental cost would have to be calculated. Solar energy used to charge the storage would not have an environmental cost.

Marginal Cost Response

The methodology used for Maine, or possibly the study CPR did for the Mid-Atlantic Solar Energy Industries Association (MSEIA)[19] could be used for Hawaii to determine the benefits of reduced marginal generation costs to all customers resulting from a reduction in demand. The Maine and MSEIA studies were based on market pricing, but the same method could be used for marginal costs. Generation units are dispatched in rank order by marginal cost, so by reducing demand for generation the costs may decline accordingly. For Hawaii, it is not clear whether such a clear relationship could be developed because the number of generation units is small and the fuel type is not as diverse as larger, mainland power grids.

[19] http://mseia.net/mseia/value-of-solar-study/

Dispatch Models

Overview

The evaluation of solar-only systems requires a time-series dataset, typically hourly, representing the generation profile of the solar resource to be evaluated. The resource may be defined by a single representative system, a measured aggregation of many installed systems, a simulated fleet, or other profile, but in all cases, the generation profile is determined by the available irradiance, temperature, and the physical attributes of the systems under study (such as tilt, azimuth, and losses).

Energy storage, however, and systems comprised of hybrid solar and storage components, do not behave based entirely on weather patterns. They are charged and discharged dynamically based on some defined control method. For example, storage could be used to flatten the overall utility peak by charging off-peak and discharging on-peak. Alternatively, the energy could be dispatched to minimize electric bills incurred by a given customer.

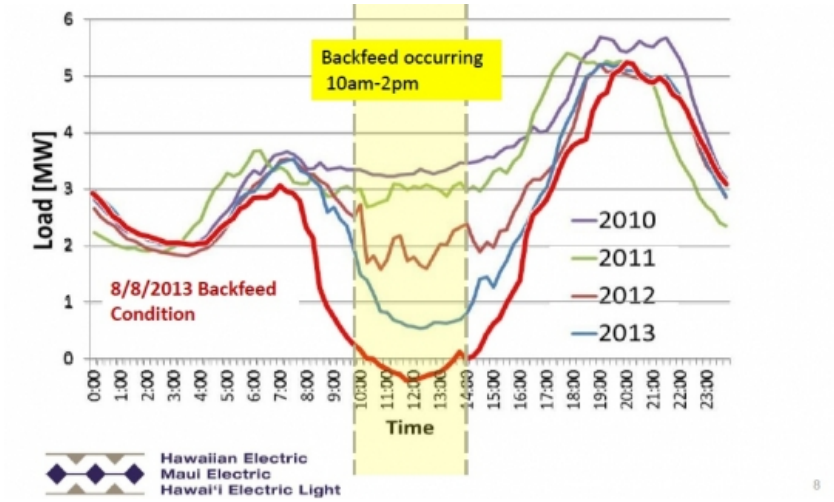
The dispatch algorithm options described here are based on

- Integration Phase (restrictions on export energy); and
- Optimization Objective (maximize value to either the utility or customer).

Integration Phase

One of the key governing factors in storage dispatch in Hawaii may be utility restrictions on energy export to the grid. These restrictions, if adopted as a measure to manage distribution constraints, would be intended to limit backfeed on circuits during peak solar times. As shown in Figure 4, backfeed occurs in HECO during the peak solar periods, so export could be prohibited during these periods.

Figure 4. Example 46 kV HECO Transformer Load, December[20]



The figure suggests that the restrictions on export during these periods would not prevent storage from providing capacity benefits, because the peak lies in the hours of about 6 pm to 10 pm. Energy could be stored from solar during the restricted hours (or any time during the day) and then discharged/exported to meet peak loads. Furthermore, storage charging during peak solar hours may provide local distribution benefits of effectively increasing load, impacting Minimum Daytime Load calculations.

Table 3 describes three "integration phases" that may come into play in Hawaii. In the first, export is prohibited entirely, the most conservative approach. In the second, export is permitted, but only during certain non-critical hours. Finally, after distribution circuits are upgraded to allow energy export, the restrictions could be removed.

Table 3. Integration Phase

Phase	Definition
Phase 1: No Export	DG and storage are permitted, but power cannot be exported beyond the meter.
Phase 2: Smart Export	Power may be exported during permitted hours only, generally outside of the solar peak, e.g., before 10 am and after 2 pm.
Phase 3: Unrestricted Export	Export may take place at any time.

[20] Taken from: http://www.greentechmedia.com/articles/read/hawaiis-solar-grid-landscape-and-the-nessie-curve

Without storage, solar power would have to be curtailed whenever export was restricted and solar power exceeded local customer load. Whether curtailment were accomplished by tripping off generation (through the use of relays) or by throttling inverter power, the curtailed energy would be lost.

Energy could alternatively be diverted through the use of time-independent loads (e.g., heat pumps, precooling, and EV charging). However, curtailment would still occur if the customer did not have these types of loads, if the loads were unavailable (e.g., water heater at maximum temperature), or if solar power still exceeded load after the addition of these loads.

Modeling of storage charging would then be handled as follows. Available solar energy in excess of load is diverted to storage whenever export restrictions are in place, time-independent loads are fully utilized, and the storage state of charge (SOC) is below 100%. If the SOC is at 100%, it cannot receive any additional charge, so solar is curtailed. The customer may continue to receive solar energy to serve its load, and load may be supplemented with utility power if necessary.

Utility Cost Optimization

This dispatch method can be used to illustrate the maximum savings to the utility. It may be considered an upper bound for the value of the benefits of solar energy with battery storage. At present, there are no rate schedules in place that would necessarily incent the customer to dispatch energy to maximize the benefit to the utility, although pricing or load signals could be provided to accomplish this and realize this benefit.

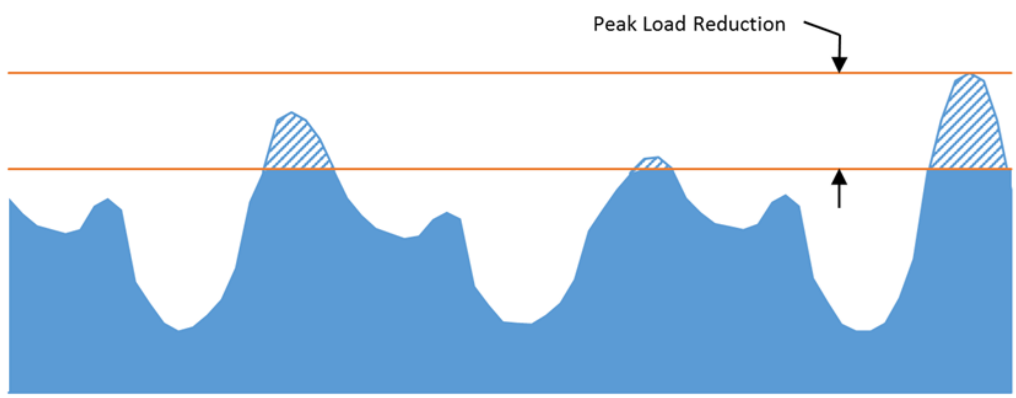
Available stored energy is dispatched in order to meet system peaks. The energy would be allocated among peak hours to meet technical constraints of the storage. For example, the SOC of the storage would be monitored for each hour and discharge would be subject to available power limits and current available stored energy.

Study scenarios could be developed in which solar production aligns with the system peak. In this case, solar energy could also be delivered to the grid, thereby avoiding losses in the storage sub-system. However, such a scenario is unlikely for Hawaii in the foreseeable future. For purposes of this methodology, solar is assumed to be non-coincident with system peak.

To model this behavior, a foreknowledge of the utility loads may be assumed for simplicity (e.g., all 8760 hours of load per year are an input to the model), although more refined methods are possible that include solar and load forecasting so that dispatch is performed using only data available. Energy is dispatched by determining the maximum annual load reduction possible for the storage resource. This is defined by a threshold, above which the storage is discharged in order to eliminate the need for supplemental utility generation above the threshold. This is illustrated in Figure 5.

The threshold is used, then, to define effective capacity.[21] The effective capacity is the annual peak load reduction: the annual system peak before storage minus the annual system peak after storage. Note that this does not necessarily correspond to the power rating of the storage system. For example, if 1 MWh is dispatched over 4 hours on the critical day, and the resulting annual peak load reduction is 500 kW (the energy is dispatched in load following mode, ramping up and down), then the effective capacity is 500 kW, even if the rating of the power conditioning system was 1 MW.

Figure 5. Utility Load Optimization (Illustrative)



Under this method, all solar energy is used to charge the storage. Solar energy that could not be stored (i.e., when SOC is at 100%) is delivered to the grid. This would have an energy value corresponding to the marginal production cost at that hour, plus loss savings.

The threshold at which storage is dispatched must be determined iteratively. If a candidate threshold is set too deep, then the resulting energy required on a given day would be in excess of the storage rating. If it is set too shallow, then the available storage would not be fully utilized.

The result is an operating regime in which the available storage discharges fully on at least one day and partially on other days. The number of days in which storage is utilized depends upon the utility seasonal load patterns. On days when the peak load is below the threshold, storage is not used.

[21] There are multiple definitions for effective capacity of DG. This model assumes that effective capacity is the reduction in annual peak load. However, the above approach could be adapted for other definitions. For example, in the Effective Load Carrying Capability, the benefits are exponentially related to load, so it may be more advantageous to limit storage dispatch (to preserve life) to only a limited number of peak hours. This would not take full advantage of the storage capacity, allowing the load to rise at certain times above what is described in the method. This is a subtlety that could be addressed in the future, if desired.

Internal system losses are included as a fixed efficiency percentage for simplicity. More sophisticated models (and technology-specific models) could be used. For example, a model could include efficiency that is variable depending on charge and discharge rates (ionic losses and power conditioning part load efficiencies). Some technologies (e.g., zinc bromine) require conditioning cycles that could be built into the model.

The generation profile to be used for valuation, then, is the sum of the discharged energy from storage, plus the solar energy delivered directly to the grid, minus the charging energy.

Customer Benefit Optimization (TOU)

Under this dispatch optimization, the customer is assumed to be on a TOU schedule, and the system is dispatched to maximize benefit to the customer. The load profile of the customer (or the load profile of a given customer class) is used as an input.

Stored energy may be used to avoid on-peak TOU charges (periods are defined by the tariff). For example, under HECO Schedule U, the priority peak is 5:00 pm to 9:00 pm, so load during this time may be served by stored energy. A variation on this approach would be for NEM customers under non-export restrictions in which stored energy could be exported.

During on-peak hours, the load would be served first by solar energy (if available), second by storage (if available), and last by the grid. During off-peak hours, solar energy would be used first to charge storage and second to serve load. This presumes that the differential between on-peak and off-peak pricing is sufficiently high to account for storage losses and loss of cycle life.[22] Otherwise the algorithm would use solar energy to serve loads first, then to charge storage.

Off-peak grid energy could also be stored. This would require a similar analysis based on price difference and impact on cycle life. If the result is favorable to storing energy, then the battery would be charged using off-peak grid energy to be used later for on-peak loads.

Customer Benefit Optimization (Demand)

As with the optimization under TOU rates, the dispatch here is intended to maximize benefit to the customer. However, in this case, the customer is assumed to be a commercial customer under a demand-based tariff. This requires an algorithm similar to the utility load optimization in which a threshold is determined, above which the storage discharges. However, the differences are:

[22] The analysis must take into account storage capital cost, cycle life, roundtrip efficiency, and electric price differential. This could be done, for example by calculating the effective cost of stored energy (off-peak price plus the amortized cost per kWh of capital cost). If the effective cost is lower than the on-peak price, then the algorithm would favor maximizing storage of solar energy and off-peak grid energy.

- The customer load is used rather than the utility load; and
- The threshold is defined for each billing month, rather than a single threshold for the whole year.[23]

The peak load reduction for each billing month corresponds to the customer demand charge savings.

Customer Benefit Optimization (Standard Rates)

Under this dispatch scenario, there is no price differential between on-peak and off-peak rates, and no demand charge (for example, HECO residential Schedule R). The customer is able to choose either the standard rate or a TOU rate, so this model assumes standard rates.[24] Under such a flat rate, there is no benefit to charging using grid energy because of losses in the battery.

Note that the customer has two options: install solar only and spill excess energy (curtailment), or install solar with storage in order to avoid spillage. This optimization method is intended to address the case in which the customer elects storage for this purpose, but remains on standard rates.

The dispatch method is simple. All load is served first by solar (as available), then by stored energy (as available), then by the grid. All solar energy in excess of load is used to first charge storage (as available), after which it is curtailed.

Study Scenarios

Study scenarios must be defined prior to a valuation study. Some considerations are offered here to identify some of the overarching decisions to be made prior to undertaking the study.

Dispatch Scenario

Depending upon study objectives, any of several dispatch scenarios shown in Table 4 may be considered. Note that under utility cost optimization, no export restrictions are assumed. This is because the storage charging and discharging is assumed to be unrestricted in order to maximize total benefit to the utility.

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[23] For simplicity, the billing month may be assumed to correspond to a calendar month. In actual practice, however, the billing months are different, and differ even among customers.

[24] See "Solar + storage in Hawaii: Making cents of time-of-use economics" why this may be the case. Available at: http://www.cleanpower.com/2015/solar-storage-hawaii/

Table 4. Dispatch Scenarios to be Considered

		No Export	Smart Export	Unrestricted Export
Objective	Utility Cost Optimization			●
	Customer Benefit Optimization (TOU)	●	●	●
	Customer Benefit Optimization (Demand)	●	●	●
	Customer Benefit Optimization (Standard)	●	●	●

It is important to note that there may be dispatch methods that are not represented in the table. It is not intended to be comprehensive. For example, some customers may utilize energy storage in part for backup purposes. Such a customer may wish to reserve a certain amount of energy (or all of the energy) for periods in which the grid is lost. This would have an impact on energy available for dispatch. Also, EV storage that could be dispatched to the grid but which also requires charging regimes based on transportation needs are not considered here.

Time-flexible Loads

The study may or may not include time-flexible loads, such as electric water heaters and EVs. These types of loads may be controlled smartly as an alternative to storage or as a complement to storage. They may be served using excess solar energy that would otherwise be delivered to the grid or lost through curtailment. The inclusion of these loads adds additional complication to the algorithms because they come with other constraints. For example, an EV must be fully charged by a specific time to meet transportation requirements.

System Ratings and Performance

Valuation studies (solar alone) typically employ a marginal PV resource, such as a 1 MW system. The size of this marginal resource is somewhat arbitrary.[25] However, by introducing storage with PV, the relative magnitudes of these components are important. For example, a 1 MW PV system coupled with a 1 MW/1 MWh storage system will result in a different value than a 1 MW PV system coupled with a 2 MW/5 MWh storage system.

The concept of a marginal resource can still be employed, but the storage ratings must be defined relative to the PV ratings. Specifically, the power rating of storage must be defined, and if the maximum charge rate is different than the maximum discharge rate, this must be included. In addition the ratio between energy and power of storage must be assumed. This could be defined in multiple study scenarios, for example, "what is the value of the system if the storage has a charge/discharge power rating equal to PV and energy to power ratios of 1 hour, 2 hours, and 4 hours?" (three scenarios).

In the case of PV, the key study assumptions are system life and degradation rate. When including storage, the key additional assumptions to be made are cycle life, calendar life, and turnaround efficiency (i.e., the combined efficiency of voltage transformation in and out of the system, the power conditioning losses in and out of the system, and storage losses such as columbic and voltaic losses and system parasitic losses).

High Value Locations

The methodology may be used for any defined region. For example, the value could be calculated for each island (Maui, Oahu, etc.) separately. In addition, certain areas within an island grid may be evaluated separately. For example, areas facing near term capital expansion or areas with better solar resource may be valued differently. Location value maps could be used as a guide in determining such study locations.

Engineering Units of Results

In solar-only studies, the resulting value is most often expressed in terms of dollars per kWh of solar generation. In the case of hybrid PV/storage systems, it becomes more complicated. The value would be expressed in dollars per kWh of net generation, but it must be understood that this is dependent upon dispatch method used and the relative size of the battery.

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[25] Although high penetration scenarios may require a definition of system size. For example, the ELCC is size dependent on assumed fleet capacity.

For example, suppose the value of a hybrid system were calculated to be, say, \$0.20 per kWh. If storage was then removed—or reached end of life but not replaced—the annual net generation would increase (storage losses would be eliminated). But this would not imply that the annual value of the system has increased due to the enhanced production. On the contrary, the value may be reduced significantly because it would have lost its time-shifting benefit.

Additional confusion may result from the fact that there are multiple flows of energy: PV production, charging energy, discharging energy, load, supplemental grid power, and "net generation" defined herein. To avoid such confusion, the results of a valuation study should clearly indicate that it is the net generation based on a specific scenario and dispatch method that is valued. It may be helpful to introduce a nomenclature such as \$ per kWh-net.

Conclusion

The methodology described in this report may be used to estimate the costs and benefits of combined solar/storage hybrid systems, placed behind-the-meter at the customer. The methodology draws heavily upon simulation and economic methods used for valuing solar-only resources, but it adds additional requirements that are needed to incorporate the storage element. A valuation study in Hawaii would require some state-specific changes, such as using accounting for displaced fuel oil rather than natural gas.

In addition, this methodology advances the prior art developed for solar-only valuation studies. Unlike solar-only resources, the hybrid resources considered here:

- May be dispatched using methods different for each rate schedule
- Include multiple power flows: from PV, to and from the battery, and may include curtailment to prevent export to the grid
- Depend upon relative sizing of storage in power rating and hours of storage

By incorporating these changes, a state-of-the-art evaluation could be performed that would determine the benefit provided by solar energy dispatched after sundown to meet Hawaii's evening peak.