PROACTIVE SOLUTIONS TO CURTAILMENT RISK

IDENTIFYING NEW CONTRACT STRUCTURES FOR UTILITY-SCALE RENEWABLES

Prepared for the Hawaiian Electric Companies by:

John Sterling, Christine Stearn, & Ted Davidovich – Smart Electric Power Alliance

Paul Quinlan, John Pang, & Chris Vlahoplus – ScottMadden Inc.

Smart Electric Power Alliance

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Executive Summary

A basic principle of power system operation is that production and consumption of electric power must be equal to each other (i.e., balanced). Variable resources such as wind and solar produce power when wind and solar energy are available, which may not correlate to periods of electricity demand. With the substantial growth of variable renewable energy generation resources on each of the Hawaiian Islands' autonomous systems, including relatively large numbers of distributed resources, Hawaiʻi's electric utilities are faced with increasing periods when electricity supply exceeds demand and actions are necessary to balance the system. Increasingly, system operators must reduce output of (curtail) renewable energy in order to preserve system reliability, because energy production capability exceeds each island's net load. Continuing to add variable resources to these systems, which face increasing periods of over-supply, requires changes to the historical commercial and contractual terms for procuring energy from these resources, which this paper will consider. Historical procurement compensated variable renewable resources strictly based on energy delivered to the utility. Some certainty of sale was provided by a combination of increasing demand on the systems (increasing the need for the energy), the right to serve energy first by designation as "must-take" resources, and with the philosophy of implementing excess energy curtailments in reverse order of project connection dates. The goal of 100 percent renewable generation requires greater flexibility in the contracting and dispatch of future projects. As the Hawaiian Electric Companies transition to higher levels of renewable resources, optimizing use of such resources helps maintain grid reliability while managing costs.[1] For purposes of this paper, curtailment is defined as a reduction in the output of a generator from what could otherwise have been produced, given the availability of the relevant variable renewable resource (e.g., solar and wind).

As the islands evolve to ever-increasing levels of renewable energy, the ability to treat any type of energy as must-take is increasingly limited. The islands serve only the demand on the island systems and cannot export excess production, as is done in other interconnected areas. Accommodating the renewable resources will displace existing generation that provides dispatchable energy, adjusted to meet demand, and affect many other characteristics to keep the power system stable and operable. Variable resources and firm renewable resources will increasingly need to provide these capabilities to adjust output to serve demand, respond to frequency, regulate voltage, etc., as the systems are transformed to economically and reliably serve the energy needs of the future with 100 percent renewable energy. This increasing contribution to grid management will necessitate changes to both procurement terms and technical and operational capabilities of all renewable resources, including distributed and variable energy resources such as solar and wind, as well as firm renewables such as biomass and geothermal resources.

[1] "Hawaiian Electric Companies" refers collectively to Maui Electric, Hawaiian Electric Company, Inc., and Hawaiʻi Electric Light Company, Inc. (collectively the "Companies").

The inability of the systems to export excess generation to neighboring systems, as is commonly done in mainland interconnections, further limits options available for excess energy.

Under a traditional Power Purchase Agreement (PPA) arrangement, variable resources have been compensated based on actual energy delivered to the utility. The need for the utility to reduce energy output during periods of low net demand results in uncertainty about how much energy the utility will be able to purchase, resulting in a financial risk to the Independent Power Producer (IPP). Basing compensation on energy delivered to the utility can have a direct, negative impact on any IPP's ability to finance projects, due to the risk of under-collected revenues resulting from curtailed energy (IPP Risk model). However, if a utility off-taker reduces the impact on the IPP by guaranteeing payments for undelivered/curtailed energy, the utility's customers may experience a higher "effective price" for energy delivered than the stated unit price under the PPA (Customer Risk model). Contractual terms based solely on energy sales fail to allocate curtailment risk in a way that is equitable to all parties, transparent to all stakeholders, and sustainable in the future with increasing need to control energy production to match demand.

As Hawai‘i moves forward towards its Renewable Portfolio Standard goal of obtaining 100 percent renewable generation by 2045, all generation sources must contribute to grid management by providing not only the ability to match supply and demand (through curtailment), but also other grid services that conventional plants have historically provided. If procured with the appropriate technical and operational capabilities and the appropriate policies that allow system operators to leverage these capabilities, renewable resource utilization can be further increased while maintaining system reliability by providing the necessary capabilities to operate a grid without reliance on conventional fossil plants or costly supplemental technologies. To that end, new contractual approaches are needed for variable renewables that incentivize the dispatchability of these resources and preserve flexibility for future system needs, all while maximizing value for the utilities' customers. This increased flexibility has the added benefit of allowing for common handling of future firm and variable resources. This report outlines some new concepts that may better achieve these objectives.

Table 1 - Preferred Contract Alternative

Solution	Description

Renewable Dispatchable Generation	○ Request for Proposals (RFP) requires bidders to break pricing into fixed ($/MW-month) and variable O&M ($/MWh) components
	  ○ The $/MW-month covers the fixed cost of the facility, ensuring that the project is financeable.
	  ○ The variable $/MWh component is based on the variable O&M cost (if any) to run the facility.
	  ○ Project selection is based on a "blended" levelized price that considers anticipated demand for the energy through a resource planning process.
	○ The seller guarantees a resource conversion factor (i.e., power curve) to convert solar irradiance or wind speed into energy production (MWh).
	○ The IPP is required to meet minimum availability metrics to ensure equipment is maintained and available for production.
	○ The IPP is required to meet technical and operational characteristics that support grid operation, including voltage regulation, disturbance ride-through, frequency response, and active power control (curtailment).
	○ The IPP is required to provide an indication to the utility of the available energy.
	○ On a real-time basis, the utility controls the output of the facility (real and reactive) based on impacts to system cost and grid reliability considerations.
	  ○ Undelivered available energy provides system reserves
	○ The utility integrates the variable resource into system planning and operations as dispatchable energy, limited by available energy used by the variable resource.

Source: SEPA & ScottMadden, 2016

For all proposed structures in this report, the long-term goal is to transition Hawai‘i away from treating resources as must-take energy, with the excess energy curtailment of resources on the basis of contract connection date, and towards treating all generation as dispatchable in nature. This paradigm shift places all generators on a more equal footing. With proper contract structures, technical and operational characteristics, and planning, this shift should lead to more economic- and reliability-focused dispatch.

Based on the work completed for this report, the Hawaiian Electric Companies' preliminary preferred option is summarized in Table 1. New PPAs would no longer be curtailed in a sequential order based on the seniority of each project's contract approval date; rather, the utility would dispatch the generating facility as required to operate the grid in a reliable manner. The fixed monthly payment would give developers more certainty of recovering the cost of the facility as long as it is maintained to meet predetermined criteria for availability; penalties would be assessed if the facility cannot meet the required metrics.[2]

[2] Because this option provides for fixed cost recovery regardless of production, it would necessarily be used only after evaluation through a resource planning process to determine customer value from anticipated energy delivered to the utility and ancillary services.

This report considers two other options:

- Capacity & Energy PPAs where under which bidders would propose pricing based on fixed (\$/MW-month) and energy (\$/MWh) components. Bidders would price their curtailment risk outlook into the proposed breakdown between fixed and variable components. For this model, the report contemplates two structures: (1) 25 percent of costs recovered via a fixed payment; and (2) 75 percent of costs recovered via fixed payment. The report also varies the amount of anticipated curtailment that is forecast in their proposal: 0 percent and 20 percent. These options provide plausible bookends for how an IPP may approach curtailment risk mitigation.
- Time-of-Day (ToD) pricing in which the energy prices are lower (or negative) during expected low-load periods, and energy prices are higher during peak load hours. The uncertainty of predicting the long-term system load profile makes this option difficult to align with forecast production costs, and therefore, appropriate energy prices.

When comparing potential pricing approaches for each of these scenarios with today's current alternatives (where either the IPP or the utility owns all of the financial risk caused by the uncertainty in the amount of energy the systems can accept), identifying ways to spread the risk more equitably can lead to less price variability for the customer and less financing risk for the developer.[3]

The modeling included in this report contemplates the impacts on new solar projects; however, these structures could be translated to any new variable or firm renewable resource, including wind, biomass, or geothermal resources. For the Renewable Dispatchable Generation model, this report assumes for simplicity that there is no variable component and that all costs are recovered via the fixed payment.

The structures identified in this report resulted in less downside risk of revenues collected for IPPs on a net present value (NPV) basis. This reduced volatility should translate into stronger project financing due to the ability to better forecast stable revenues regardless of curtailment, as compared to the traditional IPP Risk Model. Such improved financeability can be further quantified by examining the resulting Debt Service Coverage Ratio (DSCR) for each structure under zero curtailment and high curtailment scenarios. DSCR represents the likelihood that a project's future revenue streams can cover its debt obligations. Lenders frequently use this metric to set rates when financing a project. Reduced NPV risk translates into more stable DSCRs across these structures. In turn, this should lead to more attractive financing costs and, ultimately, lower PPA prices.

Lastly, the structures identified here would reduce variability for the utility's customers in the effective price of the energy delivered, after factoring in fixed and variable payments. While none of the approaches are able to eliminate curtailment risk entirely, these structures limit the upside risk in the effective price paid for delivered energy. By more

[3] All structures presented here, with the exception of the Time-of-Day Price Caps, do not assume the use of energy storage technologies.

equitably splitting economic risks with IPPs across the board, customer risk can be mitigated as well.

Continued research into how customers may be impacted by these new agreements is ongoing. Potential unintended consequences as a result of increased fixed payments and the curtailment conditions need to be identified and further discussed. One potential consequence identified is that if a PPA is considered a capital lease under current accounting guidance (or a lease under recently issued revised accounting rules), the present value of the estimated lease payments would need to be reflected as a liability on the utility company's financial statements. The impact to the utility's financial statements from having to recognize the present value of the estimated lease payments can be significant to the Hawaiian Electric Companies' credit metrics and cost of capital. Recently revised accounting rules may increase this risk, and such assessment is ongoing.

Detailed conversations with key market participants are also needed to ensure that any future procurement practices are structured in a transparent, fair, and equitable manner.

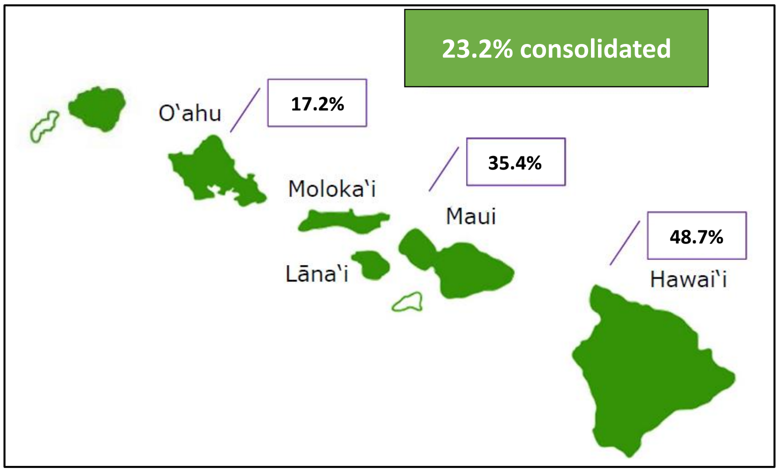
The systems have finite quantities of demand, and as a result, have finite need for new resources to meet the demand. The procurement of resources through contracts that recover fixed costs requires careful resource planning to avoid fixed expenses for resources without consumer benefit. The mix of energy resources must be designed to cost-effectively meet customer demand, while maintaining acceptable reliability. The evaluation of resource type and location must include its correlation with net demand and total impacts on system interconnection and operational costs. Care must be taken to design a mix of resources whose fixed costs that result in a net cost-benefit from the energy production and grid services, compared to resource alternatives. Alternative resource considerations can include storage options, dispatchable renewable resources, demand response, and conversion of conventional fossil plants to renewable resources through fuel conversions.

Hawai'i's place as the nation's leader in renewable energy adoption places an increasing importance on including these considerations, with a resource plan to meet 100 percent renewable energy goals while managing costs and ensuring grid stability. With time, as other states transition away from conventional generation and increase the amount of intermittent renewable resources on their systems, the lessons learned in Hawai'i will be valuable to utilities and grid operators in much larger interconnected systems. The examples and successes from Hawai'i that emerge from this effort will ripple across the industry and set the stage for a new way of thinking about renewable resources.

State of the State

Hawai'i is leading the United States with a vision of 100 percent renewable energy by 2045. This vision challenges the state's utilities to tap plentiful, natural, clean sources of power, while building grids, interconnection infrastructure, and business models to make these power sources accessible and affordable. As of December 2015, the Hawaiian Electric Companies, comprised of Hawaiian Electric Company, Inc. (Hawaiian Electric), Maui Electric Company, Limited (Maui Electric), and Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light), obtained over 23 percent of their generation from renewable energy sources[4]

Figure 1 - Renewable Energy Utilization, December 2015



Source: Hawaiian Electric Companies, 2016

The Hawaiian Electric Companies serve 95 percent of the state's 1.4 million residents on the islands of Hawai'i, Lana'i, Moloka'i, Maui, and O'ahu. To meet the energy needs of Hawai'i's residents and integrate higher levels of renewable energy, the Hawaiian Electric Companies are working aggressively to empower their customers and communities with affordable, reliable, clean energy, and provide innovative energy leadership for Hawai'i. To achieve that vision, through their resource planning process, the Hawaiian Electric Companies have produced a Power Supply Improvement Plan (PSIP) to reach the 2045 goal of 100 percent of renewable resources by:[5]

- Implementing a smart grid foundation project;
- Implementing a demand response management system (DRMS);
- Pursuing market-based distributed energy resources (DER) for O'ahu, Hawai'i Island, and Maui and high distributed generation (DG) in the form of solar photovoltaics (PV) for Moloka'i and Lana'i;
- Installing circuit level improvements on all islands;

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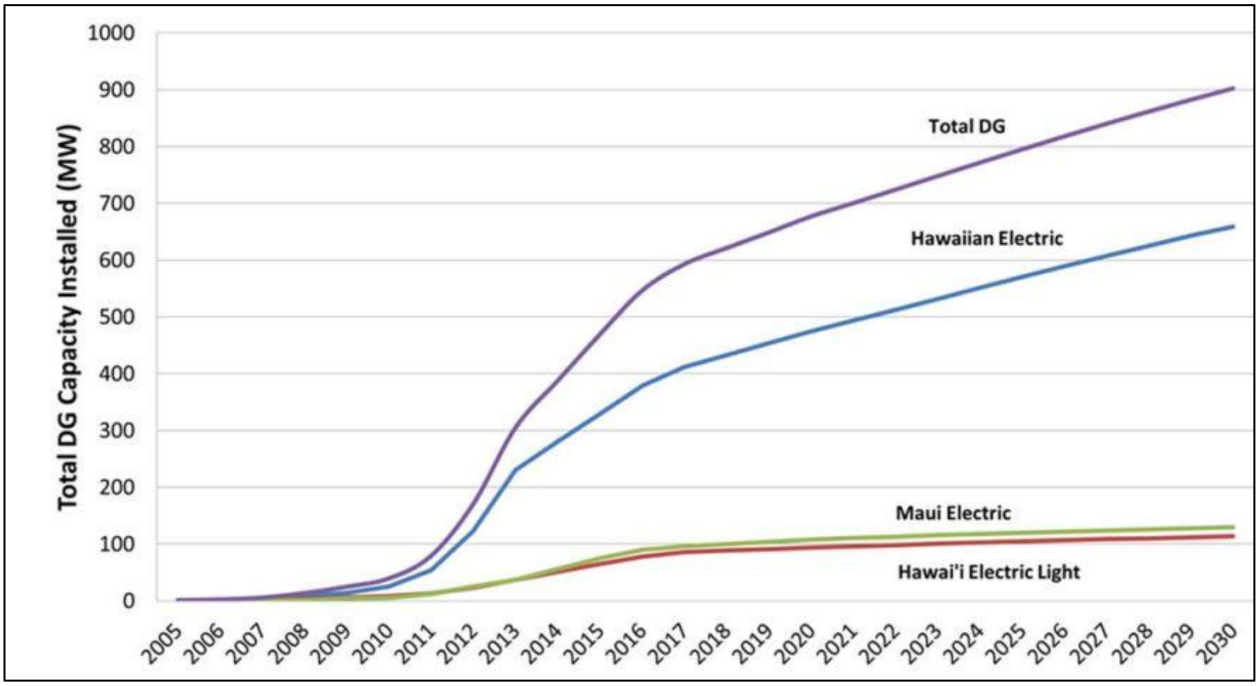
[4] Under Hawai'i's Renewable Portfolio Standards, each electric utility company that sells electricity for consumption in Hawai'i must establish the following percentages of "renewable electrical energy" sales by December 31 in each of the following years: 10% by 2010, 15% by 2015, 30% by 2020, 40% by 2030, 70% by 2040, and 100% by 2045.

[5] Hawaiian Electric Companies' "April 2016 PSIP Update Report", Docket No. 2014-0183 (April 1, 2016). All references to the PSIP in this document refer to this version.

- Pursuing energy storage options;
- Implementing community-based renewable energy;
- Issuing RFPs to seek over 350 MW of additional renewable energy by 2022;
- Researching alternative curtailment policies;
- Deactivating generation not well suited to support the integration of renewables; and,
- Improving flexibility of existing generation.

Electricity prices in Hawai'i are the highest in the country at over twice the national average. This has incentivized utility customers to evaluate and often deploy their own customer-sited DERs, such as rooftop solar. To that end, the Hawaiian Electric Companies forecast nearly tripling the amount of DERs by 2030.

Figure 2 - DG Penetration Forecast by Utility



Source: Hawaiian Electric Companies, 2014 [6]

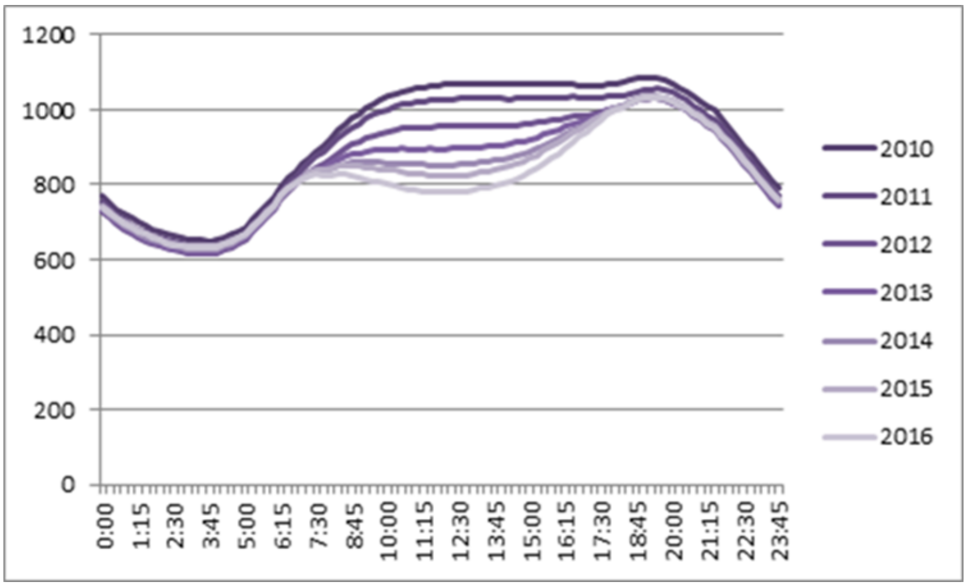
In conjunction with installed and planned DER generation, the Hawaiian Electric Companies also plan to significantly increase the amount of utility-scale wind and solar generation on each island. Because DERs meet a large portion of each islands' load, and existing interconnection programs do not provide a capability to control the output of these resources, the amount of available load to serve with utility-scale renewable resources is increasingly limited during peak sunshine hours. The resulting net load profile

[6] *See* Hawaiian Electric Companies' Letter submitting its Distributed Generation Interconnection Plan ("DGIP"), filed on August 26, 2014 in Docket 2011-0206, Reliability Standards Working Group.

will require increased access to flexible generation resources to manage supply and demand.

As shown in Figure 3, representing load profiles for O‘ahu, gross and net system load are nearly identical and can be approximated by the 2010 load shape. From 2011 onward, however, net system load begins to exhibit the dip in mid-day due to behind-the-meter PV. Despite this challenge, the Hawaiian Electric Companies are committed to finding ways to maintain safe and reliable operations while reducing the amount of load that conventional generation serves.

Figure 3 - O‘ahu Net Load Potential



Source: Hawaiian Electric Companies, 2016

Challenges in Contracting for Utility-Scale Renewables

Increasing penetration of distributed PV has created a surplus of daytime, non-dispatchable generation on all of the Hawaiian Islands.[7] This generation, which utilities do not directly control, is effectively "must-take"; that is, the utilities must manage other conventional and renewable generation resources around the output of these systems.

The large amount of distributed PV that exports to the grid, relative to total system demand, exceeds levels in other parts of the country. Incorporating large amounts of non-dispatchable utility-scale renewable resources then becomes a challenge – the system simply does not have the demand to accept all of the production at some times during the day. Subsequently, the Hawaiian Electric Companies are faced with the reality of needing to curtail utility-scale renewable resources to maintain grid stability and reliability.

The purpose of this report is to identify potential new approaches to contracting for utility-scale variable renewable energy resources that enable a focus on economic dispatch and system reliability going forward. Transitioning must-take resources into dispatchable resources (similar to conventional generators) could spur higher penetration levels of these assets without incurring an increased financial burden for customers or IPPs. Any outcome that mitigates those challenges will empower Hawaiʻi to move towards its vision of an affordable and reliable 100 percent clean energy future.

Impact of Curtailment Concerns

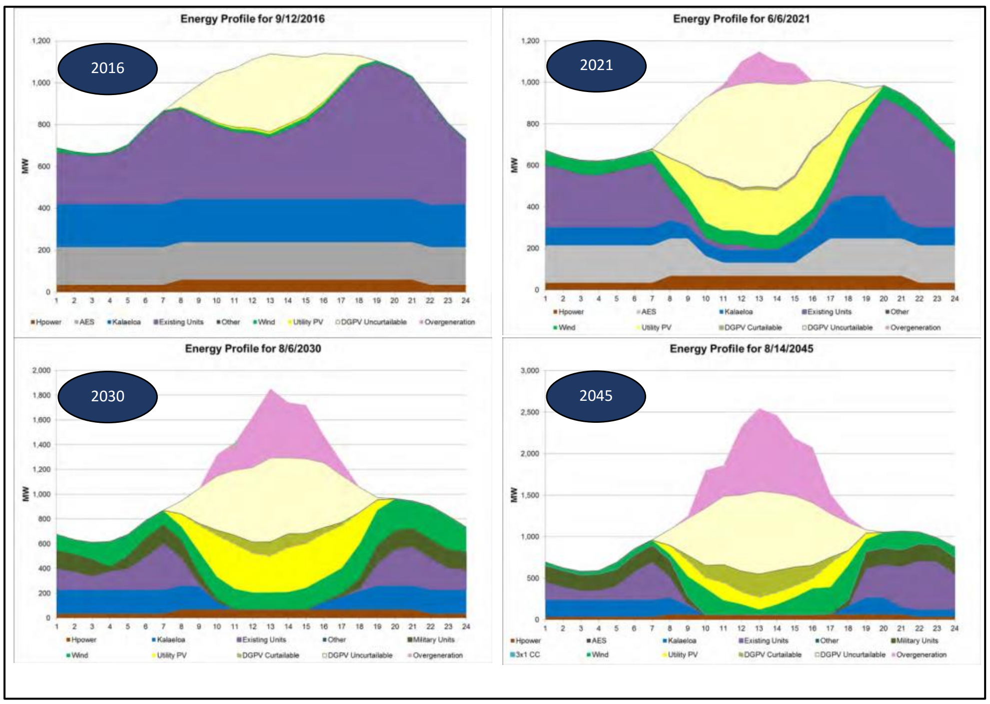
Curtailment is the reduction of a given purchased power resource below its otherwise theoretical output level. Curtailment is largely an issue reserved for resources that do not rely on a stored fuel source (e.g., coal, natural gas, biomass, etc.). For conventional generation resources that have the ability to stockpile their fuel supply, a decrease in the dispatch of the resource from its maximum output level does not *necessarily* forego energy sales forever; rather, it likely just delays the conversion of their fuel source into electricity. For solar and wind assets, however, that electricity is permanently foregone. The reality of curtailment is becoming a recurring theme on many islands in Hawaiʻi for its utility-scale wind and solar projects. Variable renewable resources such as wind and solar are not dispatchable by nature, meaning their production profile cannot be modified to meet system needs without forfeiting energy production. In other words, there is no ability to defer production to a more valuable time without the use of energy storage. The availability of sunlight or wind dictates energy production. The production can only be used or curtailed, resulting in the potential for lost sales for the asset owner.

[7] Most distributed generation in Hawaiʻi is contracted via Net Energy Metering (NEM), which historically has been compensated at retail rates. NEM systems and associated compensation are not within the scope of this report, which focuses on utility-scale transactions only.

A further complication for variable projects is that anticipated energy production (and, therefore, sales) requires an estimated availability of the wind or solar resource. The resulting capacity factor represents the amount of energy produced from the installed capacity. A project with a higher capacity factor than anticipated may experience greater curtailment risk than expected, although net energy sales could still be higher than planned.[8]

This issue is not isolated to the state of Hawai'i. Concerns have arisen in states such as California where at high levels of distributed solar penetration, other large and low cost renewable assets may be curtailed during light load situations;[9] however, due to its small islanded market and high penetration of distributed solar, the magnitude of curtailment necessary to balance supply and demand in Hawai'i far outpaces that of other regions of the country. As shown in Figure 4, increasing distributed PV creates overgeneration in greater and greater quantities during sunny daytime hours, requiring other generators to modify dispatch.[10]

Figure 4 - Future Daily Load Profiles for Hawaiian Electric



Source: Hawaiian Electric Companies, 2016

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[8] For simplicity purposes, this report does not consider the implications of capacity factor forecast inaccuracies on curtailment.

[9] For a discussion on the frequency of this at different renewable penetration levels, *see* "Impact of High Solar and Energy Storage Levels on Wholesale Power Markets" (Black & Veatch / SEPA 2015).

[10] *See* April 2016 PSIP Update Report, pages 5-11, 5-13, 5-15, and 5-17.

Given the isolated nature of the independent grids on each of the Hawaiian Islands, the ability to dispatch the output of renewable generation is inherently an essential tool to manage system stability and is likely the lowest cost solution in many circumstances given the large quantities of DERs on this autonomous system. It is conceivable that curtailment levels on O'ahu may be 10 percent (of a given generator's output potential) or greater, and 20 percent possibly up to as much as 50 percent on Maui and Hawai'i Island. If compensation for IPPs is based on energy sales only, these non-trivial curtailment levels will have a direct and measurable impact on the financeability of large renewable projects in Hawai'i. Moreover, increasingly high levels of must-take energy creates operational constraints on system operators, creating challenges for balancing and managing costs to optimize the total resource portfolio.

Translating Curtailment Risk into Project Economics

PPA Price = The price stated in the PPA for energy produced by the solar asset; or, in a take-or-pay contract, the price stated for energy that is or could have been produced.

Effective $/MWh = The all-in price that customers pay for energy delivered, after considerations for fixed and variable costs, and payments for undelivered energy.

Executing a PPA for large renewable resources is increasingly complicated by the uncertainty over curtailment. There are two main ways today that this curtailment risk has been captured, representing opposite ends of a risk spectrum:

- Placing all risk on the developer (IPP Risk Model); or,
- Placing all risk on the utility and its customers (Customer Risk Model).

In the IPP Risk model, the PPA provides for energy purchases at a given $/MWh price point with no minimum required offtake (or minimum purchase commitment) by the utility. In essence, the utility can curtail the asset and not incur any financial penalty for doing so. The developer then must attempt to forecast the likelihood of curtailment into its energy price so that the project can be financed.

The alternative Customer Risk approach, sometimes known as the "take-or-pay" contract, is structured such that the utility must pay for any energy that is produced or could have been produced if not for being curtailed. For the IPP, this type of agreement is much easier to finance and can allow for lower PPA prices. For the utility and its customers, however, this type of agreement results in payment for energy that is never delivered – a result that imputes a higher effective energy price for the resource in question.[11] This approach can also be administratively complex, relying upon calculations of "available" versus "delivered" energy that can be challenging to calculate and verify.

[11] Effective $/MWh does not include additional costs associated with the provision of electrical service, such as delivery fees, grid services, etc.

At times when there is greater certainty of energy purchases due to minimal need for curtailment, the difference in price bid to the utility should be minimal between these two structures. The price diverges, however, as curtailment risk appears.

But that is only half the story. The actual impact to developers and consumers is the delta between *anticipated* curtailment and *experienced* curtailment. Consider, for example, a utility-scale solar asset that would normally cost $100/MWh over the 20-year term of its PPA. This project has all assurances that the energy will be delivered and sold, with no risk of curtailment. If we insert the anticipation of curtailment at 20 percent, the price for the same project increases to $125/MWh so that the developer retains the revenue stream needed to finance the project. Even if it is a take-or-pay agreement and the price remains at $100/MWh, the utility and its customer base effectively pay $125/MWh for the energy that is ultimately delivered.

The challenge arises when the experienced curtailment varies significantly from what is anticipated at the time of contract execution. Continuing with the example above, consider two scenarios: (1) no anticipated curtailment, and (2) anticipated curtailment for a utility-scale solar asset.

Table 2 demonstrates the impacts to a project's revenue stream when curtailment is unexpectedly introduced into a project.[12] If the IPP owned all of the risk associated with curtailment, they could conceivably under-earn by several million dollars. In this example, the delta in revenue could pose severely negative implications on project finance, including the repayment of debt for the asset. For a take-or-pay contract, customers would be paying as much as 43 percent more per MWh for the energy delivered than was originally anticipated.

Table 2 - Impacts to Project Economics with No Curtailment Anticipated

	IPP Risk Model		Customer Risk Model
	Project NPV	Change in Project NPV	Take-or-Pay Effective $/MWh
No Actual Curtailment	$1.06 M	$ -	$100
10% Actual Curtailment	$0.15 M	($0.91 M)	$111
20% Actual Curtailment	($0.76 M)	($1.82 M)	$125
30% Actual Curtailment	($1.67 M)	($2.73 M)	$143

Source: SEPA & ScottMadden, 2016

[12] Assumes a 10-MW solar project and the anticipated revenues over a 20-year timeframe.

When curtailment risk is known in advance, there is still the potential for significant impacts to the overall economics of the project. As shown in Table 3, if the solar developer anticipates 20 percent curtailment over the course of the project, they will adjust the price of the PPA to ensure revenues are maintained. A 10 percent swing in actual curtailment, however, can still negatively impact the developer (from an NPV perspective). For customers under a take-or-pay agreement, they would pay that higher PPA price for any energy delivered. Curtailment below 20 percent would still have an effective rate of $125/MWh, which is 10-25 percent higher than the price needed to meet the developer's revenue requirements. Curtailment at the 30 percent level would again result in paying an effective price of $143/MWh for energy delivered.[13]

Table 3 - Impacts to Project Economics with 20 Percent Curtailment Anticipated

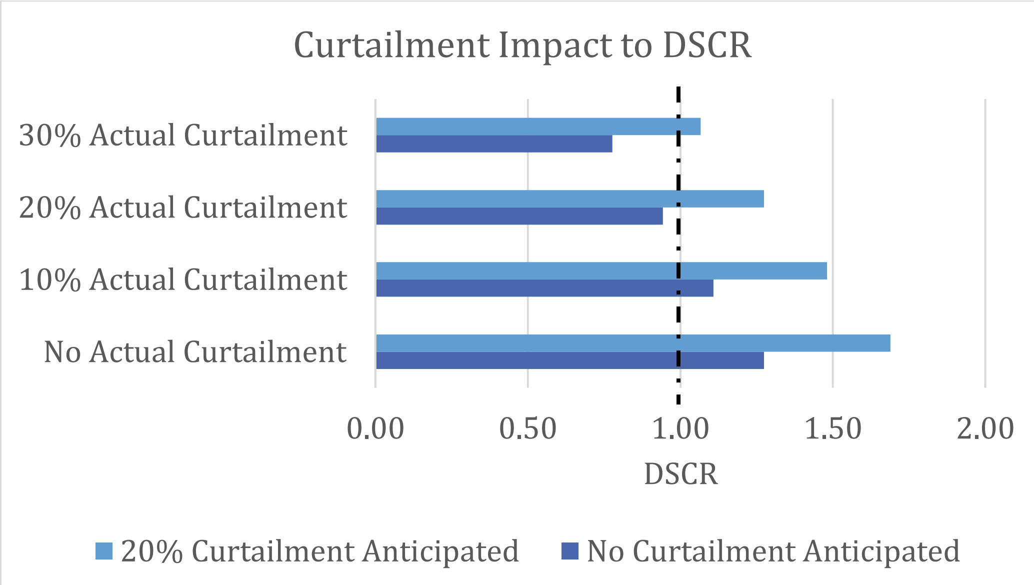
IPP Risk Model			Customer Risk Model
	Project NPV	Change in Project NPV	Take-or-Pay Effective $/MWh
No Actual Curtailment	$3.33 M	$2.27 M	$125
10% Actual Curtailment	$2.20 M	$1.14 M	$125
20% Actual Curtailment	$1.06 M	$ -	$125
30% Actual Curtailment	($0.08 M)	($1.14 M)	$143

Source: SEPA & ScottMadden, 2016

Another metric that provides visibility into project health and financeability is the DSCR. DSCR measures a project's ability to meet debt obligations with net operating income. In this analysis, DSCR is calculated using earnings before interest, taxes, depreciation, and amortization. A ratio greater than 1.0 indicates that net operating income exceeds debt obligations. A project becomes more attractive (from a financing perspective) as the DSCR increases. Figure 5 outlines the impact to a project's DSCR based on the risk of curtailment. In the face of likely curtailment, a developer would need to raise its PPA price to maintain the targeted DSCR.

[13] One natural reaction to addressing curtailment is to promote energy storage as part of projects. While this solution is discussed further below, at certain levels, curtailment of a resource may in fact be lower cost than requiring storage. Based on the pricing assumptions used in this report, it is actually more cost effective to curtail 60% or more of a project before its effective price reaches parity with solar plus storage. As storage costs decrease, however, including storage as part of future solar projects may warrant consideration.

Figure 5 - Curtailment Impact to DSCR



Source: SEPA & ScottMadden, 2016

Millions of dollars can shift between customers and developers depending upon the difference between anticipated curtailment at the time of contract execution and actual curtailment levels experienced over the life of the project. This swing represents a major unknown for all parties, and can significantly impact how developers seek to finance agreements and how the Hawaiian Electric Companies (and the utilities' regulators) view the value proposition on behalf of customers.

Grid Stability & Reliability in a Majority Renewable Future

A certain combination of resources, which includes synchronous generation, is required to maintain system reliability. Disturbances in frequency, from either load fluctuations or generation trips, is an issue that must be actively managed on any system. For island systems such as exists in Hawai'i, this issue is exacerbated. With no interconnected neighbors to provide support in the form of shared reserves or ancillary services, the grid is highly susceptible to system disturbances from generation trips or sudden load changes. As distributed solar penetration has increased, the potential for load and frequency fluctuations has been exacerbated – weather changes can cause generation loss and increased load on a moment's notice.

Maintaining a reliable system requires a delicate balance between load and generation. If load increases without a commensurate increase in generation, the frequency will drop. If generation is overproduced compared to load, frequency increases. With frequency, small changes can be problematic. Synchronous generation is critical to providing system inertia, which can be thought of as "frequency friction". Inertia simply means that there is a large rotating mass generator that – if frequency drops unexpectedly – can help slow that drop and ramp up its own generation levels to restore system frequency.

As renewable penetration increases, the amount of available synchronous generation has decreased in kind. In island systems such as Hawai'i, more of one resource must translate into less of another, because there are no neighboring systems with which to exchange energy. The Hawaiian Electric Companies have already taken steps to reduce the minimum run levels of its conventional generation resources; however, as the state moves towards its 100 percent clean energy future, the ability to continue to run conventional generation to provide system inertia may become difficult if not impossible.

This factor also has important implications for the utilities' ability to provide ancillary services. Ancillary services support the transmission of energy between generation and load and ensure that the system maintains reliable operational characteristics. Two key ancillary services warrant mention with relation to the Hawaiian Electric Companies' systems:

- Spinning reserves are generators that are synchronized to the grid but have available headroom (unloaded generation) to respond to system needs on a moment's notice by increasing their generation level.
- Regulation/frequency response are generators that ramp themselves both up and down on a moment-by-moment basis to respond to the natural variations in supply and demand in an effort to maintain frequency.

Ancillary services represent an added (and often hidden) cost to an energy system's economics. In organized Regional Transmission Organization/Independent System Operator (RTO/ISO) markets such as the Electric Reliability Council of Texas (ERCOT) or the PJM Interconnection, active ancillary services markets create transparency around costs and pricing and incent resource owners to provide ancillary services to the grid.[14]

Table 4 – 2014 Ancillary Services Pricing from Organized Markets

Ancillary Service	PJM	ERCOT
Spinning reserves	$4.21/MWh	$12.89/MWh
Regulation	$43.68/MWh	$14.22/MWh

Source: SEPA & ScottMadden, 2016

Large markets such as PJM and ERCOT have a plethora of available generation that can bid in and provide these types of services to the grid. In Hawai'i, each individual island's available generation is all that can provide these supporting services for grid reliability. With a predominantly oil-fired fleet, Hawai'i's conventional generators likely have a higher

[14] http://www.pjm.com/markets-and-operations/ancillary-services.aspx

https://www.potomaceconomics.com/uploads/ercot_documents/2014_ERCOT_State_of_the_Market_Report.pdf implied cost to provide spinning reserves and frequency regulation services than the natural gas-driven markets in PJM and ERCOT.

In 2012, GE Energy Consulting conducted a study for the Hawaiʻi Natural Energy Institute (HNEI) on the capability of certain generators to provide ancillary services.[15] Examining only the Kahe and Kalaeloa plants on Oʻahu and their opportunity costs to provide 1 MW of regulation services, GE found an approximate range of costs from $20-85/MWh per unit.[16]

Table 5 - Approximate Opportunity Costs at Kahe and Kalaeloa Plants

Plant-Unit	Nameplate – MW	Approximate Opportunity Cost
Kahe-1	81.6	$20/MWh
Kahe-2	81.6	$25/MWh
Kahe-3	85.8	$30/MWh
Kahe-4	90.9	$25/MWh
Kahe-5	134.9	$30/MWh
Kahe-6	134.9	$20/MWh
Kalaeloa-1	119.2	$85/MWh
Kalaeloa-2	119.2	$85/MWh
Kalaeloa-3	61	$40/MWh
Weigthed Average		**$42/MWh**

Sources: GE Energy Consulting & HNEI, 2012; EIA, 2016; SEPA & ScottMadden, 2016

While this specific study is a bit dated (and due to oil prices at the time of its publication may be inflated relative to operating costs today), it is illustrative of the fact that non-trivial costs are a natural part of maintaining system reliability in the provision of certain ancillary services. The actual cost of providing these services is dependent upon several factors, including the amount of reserves required, fuel costs, and available resources. To that end, the Hawaiian Electric Companies are in the process of filing ancillary services costs as part of a recent docket related to demand response.[17] Until those more accurate values are available, the costs listed in the tables above can be considered proxies for the purposes of this report.

With ever-increasing penetration levels of distributed PV, and a desire to phase out oil-fired conventional generation over time, solutions must be developed so that utilities can continue to provide system inertia and ancillary services over the long term.

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[15] GE Energy Consulting. December 2012. Ancillary Services Definitions and Capability Study.

[16] *Id.,* Part 2, Task 3-4, Final Report (December 19, 2012). *See* slide 44.

[17] Docket 2015-0412 – Application for Approval of Demand Response Program Portfolio Tariff Structure.

Potential Contract Structures for Utility-Scale Renewables

Facilitating a future of 100 percent renewable energy in the most cost-effective manner will require a fundamental shift in thinking on how to contract for large scale renewable resources. This is driven by the need to proactively address and plan for high curtailment scenarios, while also identifying potential sources of ancillary services over the long term. This section of the report identifies three approaches to restructuring PPAs and redefining how curtailment is managed: Capacity & Energy PPAs; Time-of-Day Price Caps; and, Renewable Dispatchable Generation.[18] All three of these address curtailment risk allocation issues, and the latter also provides an avenue for renewable assets to provide ancillary services for the first time. For all of these structures, any new PPA would move away from reverse chronological curtailment decisions and towards curtailment based on economics or system reliability needs.

I. Capacity & Energy PPAs

Renewable energy projects are fuel-free resources, where virtually all of the costs of the assets are tied up in the cost to finance and construct the facility; however, the historical PPA payment stream for these resources is entirely variable in nature. When curtailment is introduced, the IPP loses revenue that will never be recovered, which has negative implications on project financing. Riskier projects inherently result in higher costs of borrowing, driving up the ultimate price offered to the utility.

The first model proposed for future contracts in Hawai'i is targeted at creating more surety in revenues for IPPs so that projects become less risky – the Capacity & Energy PPA. Under this contract structure, the utility creates an RFP that specifically requires bidders to allocate their pricing into two components: a $/MW-month fixed charge and a $/MWh energy charge. The fixed charge provides bidders the ability to identify a guaranteed cash flow stream for their project. Curtailment risk is limited to the energy charge only.

This structure provides the opportunity for the market to price its own risk outlook on curtailment into the bidding process. Rather than forcing either the utility and its customers or the IPP to own all risk, this revised contract structure creates a sharing of curtailment risks and associated costs. Further, it creates a more transparent way to monetize that risk. Executing a contract that allocates capacity and energy payments for a renewable resource necessarily also contains clauses that hold IPPs to minimum availability metrics or risk forfeiting some of the capacity payment each month. Overall, however, this approach should result in less price risk for customers than would be experienced in a take-or-pay arrangement; customers are only exposed to the fixed

[18] These three main approaches were the result of a larger effort to identify a wide variety of approaches that could be pursued. A summary of the approaches considered but not included in the final analysis is available in Appendix A: Additional Models Considered.

portion of the project's total revenue stream when curtailment occurs as opposed to the full take-or-pay PPA price.

For developers, the strategy behind how to bid into this type of RFP is likely founded in their view of curtailment risk and need for more predictable cash flows. Two main triggers are now available for the developer in bidding to the utility: (1) the amount of revenues recovered in a fixed manner; and (2) the level of curtailments that are anticipated over the contract life.

Table 6 – Project Economic Implications: 25 percent of Project Costs Recovered in Capacity Payment

	0% Anticipated Curtailment			20% Anticipated Curtailment		
	Project NPV	Change in Project NPV	Customer Effective $/MWh	Project NPV	Change in Project NPV	Customer Effective $/MWh
No Curtailment	$1.06 M	$ -	$100	$2.76 M	$1.70 M	$119
10% Curtailment	$0.38 M	($0.68 M)	$103	$1.91 M	$0.85 M	$122
20% Curtailment	($0.30 M)	($1.36 M)	$106	$1.06 M	$ -	$125
30% Curtailment	($0.98 M)	($2.04 M)	$111	$0.21 M	($0.85 M)	$130

Source: SEPA & ScottMadden, 2016

Table 7 – Project Economic Implications: 75 percent of Project Costs Recovered in Capacity Payment

	0% Anticipated Curtailment			20% Anticipated Curtailment		
	Project NPV	Change in Project NPV	Customer Effective $/MWh	Project NPV	Change in Project NPV	Customer Effective $/MWh
No Curtailment	$1.06 M	$ -	$100	$1.63 M	$0.57 M	$106
10% Curtailment	$0.83 M	($0.23 M)	$108	$1.34 M	$0.28 M	$115
20% Curtailment	$0.61 M	($0.45 M)	$119	$1.06 M	$ -	$125
30% Curtailment	$0.38 M	($0.68 M)	$132	$0.78 M	($0.28 M)	$138

Source: SEPA & ScottMadden, 2016

As shown in Table 6 and Table 7, the customer's Effective $/MWh upside risk has been reduced compared to today's paradigm, while the NPV at risk for the IPP has also been limited. By allowing IPPs to factor their own risk profile into this structure, while providing for some floor level of revenue recovery, the Capacity & Energy PPA creates a platform for all participants to share the risk of curtailments equitably. It reduces the revenue at risk for the developer and reduces price fluctuations for the end customer. The ability for IPPs to manage two different levers (fixed cost recovery and anticipated curtailment) in their future bids to the utility allows the market to define curtailment risk much more effectively.

II. Time-of-Day Price Caps

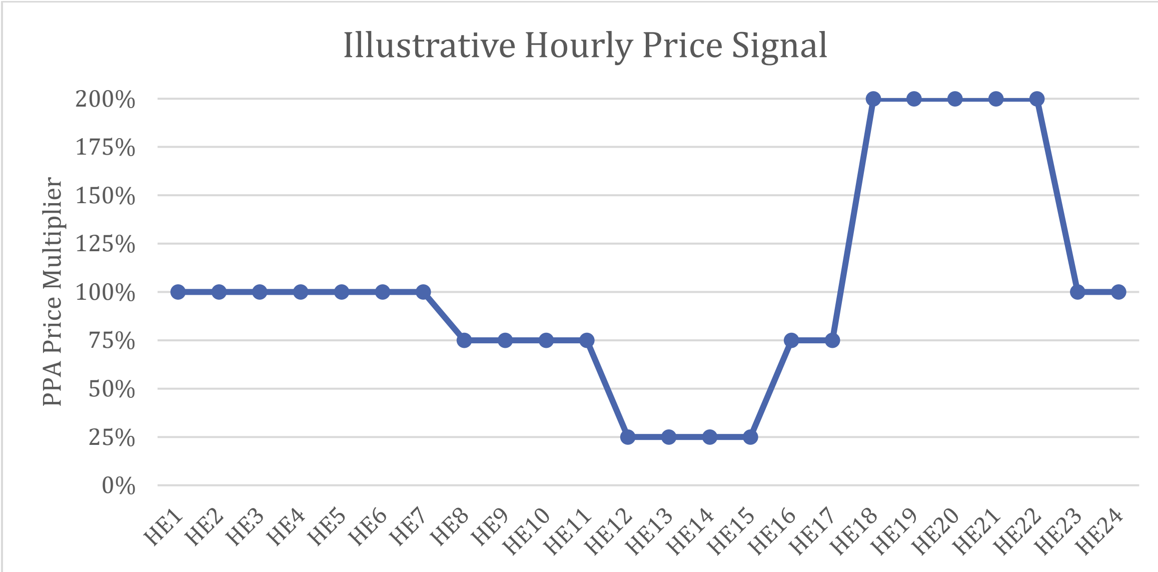
The second model under consideration creates an avenue for prospective bidders to use innovative system technology and design in a much more transparent manner. Traditionally, RFPs are oriented towards identifying the least cost project over the course of the contract term, which is typically 20 years. In some cases, utilities signal to the market specific hours of delivery that are more valuable than others in order to provide signals on relative value of production. This same idea can be leveraged to create strong incentives for developers to engineer solutions to limit curtailment.

In the Time-of-Day Price Caps (ToD) contract structure, the utility issues an RFP that sets firm caps on the price it is willing to pay for energy delivered in each hour of the day, and potentially, for different months of the year. Bidders respond with prices up to, but not exceeding, the price caps by hour. Alternatively, the utility could establish a PPA price multiplier that limits what it would pay of the PPA price during each hour of the day (*see* Figure 6). Once the contract is executed, the utility pays the IPP based on those ToD price caps for energy delivered.

Because the Hawaiian Electric Companies' systems currently have excess generation from distributed PV in the daytime hours, it is highly likely that a ToD RFP would set extremely low (or negative) prices for those same hours, with higher prices allowed for the delivery of energy in hours where net load is highest.[19]

[19] The multipliers selected for Figure 6 and the associated modeling are illustrative in nature only and are not the result of detailed system dispatch analytics. Rather, they are meant to approximate an exaggerated signal to developers to shift power to better match system net load. Actual PPA price multipliers would be the result of a detailed system modeling exercise.

Figure 6 - Illustrative Time-of-Day Price Cap Curve



Source: SEPA & ScottMadden, 2016

This structure, in which price transparency that proactively takes curtailment into consideration is presented to the market, should create strong incentives for IPPs to engineer innovative solutions that maximize their revenue potential while minimizing the likelihood of curtailed energy. One potential solution could be the incorporation of energy storage; another could be to focus on alternative renewable technologies such as fuel cells. A solar developer could still theoretically bid in and win the RFP, delivering only during hours that are likely lower on the ToD cap scale. If curtailment becomes necessary, this structure would dictate that the price paid for undelivered energy would be set at the ToD caps negotiated in the contract, with curtailment events prioritized towards the lowest caps. This cements the incentive for the developer to be flexible in shifting production away from periods when it can be anticipated that energy is less valuable. And it is not inconceivable that at some point in the future, negative price caps could be required to create enough economic incentive to shift production into the hours with the highest value.

To allow flexibility in the future, as net load patterns changes over time, the PPA may also allow for regular adjustments (e.g., every 5 to 10 years) to the ToD cap curve, as long as the utility maintains a commitment to keep the overall volume under the cap constant. For example, if distributed storage becomes prevalent at the residential level, the net load shape served by the Hawaiian Electric Companies would look substantively different from the illustrative load shape contemplated in Figure 6. Building in a refresh to the ToD price caps at specific intervals would significantly increase the flexibility offered by projects under this structure.[20] One factor working against this structure is that it is extremely complicated, both for the utility in how it designs the price caps and subsequently reviews proposals, and for the IPP in how it attempts to shape production to meet the needs of the utility.

For simplistic purposes, assume two different approaches to building a project for this price structure. In the first approach, a solar developer builds a traditional south-facing project. Given the price multipliers outlined in Figure 6, the developer knows in advance that generation during the middle of the day, which coincides with solar DER production, would only be paid out at 25 percent of the applicable PPA price. To make their project financially viable, the PPA price would therefore need to be set at $192/MWh, so that production during periods that allow for higher pricing can generate enough revenue overall.

Table 8 - Project Economic Implications: Time-of-Day Alternatives

	South-Facing Solar PPA Price = $192/MWh			South-Facing Solar with Storage PPA Price = $238/MWh		
	Project NPV	Change in Project NPV	Effective $/MWh	Project NPV	Change in Project NPV	Effective $/MWh
No Actual Curtailment	$1.1 M	$ -	$100/MWh	$2.7 M	$ -	$274/MWh
10% Actual Curtailment	$0.6 M	($0.5 M)	$106/MWh	$2.7 M	$ -	$275/MWh
20% Actual Curtailment	$0.2 M	($0.9 M)	$113/MWh	$1.5 M	($1.2 M)	$284/MWh
30% Actual Curtailment	($0.2 M)	($1.3 M)	$122/MWh	($0.2 M)	($2.9 M)	$298/MWh

Source: SEPA & ScottMadden, 2016

To the utility's customers, the same revenue stream and associated energy is delivered. Assuming no curtailment occurs, the Effective Price is $100/MWh. As curtailment is incorporated, revenue allocation is shifted to times of the day when curtailment is less likely. The IPP retains a positive project NPV across virtually all curtailment scenarios modeled. For the customer, their upward price risk (on an Effective $/MWh basis) is limited compared to today's take-or-pay structure as well.

A second approach for the IPP is to incorporate energy storage into the project. For purposes of this report, a 17-MW lithium-ion battery, which is large enough to shift several hours of on-peak production, was incorporated into the project. The battery was modeled to shift energy out of the lowest tier price cap period and into the highest tier.

[20] This flexibility would likely come at a cost, as it may necessarily require storage to be incorporated. Alternatively, it could favor more dispatchable renewable technologies such as biomass and biogas.

As shown in Table 8, this battery shifts enough energy in its base design to avoid up to 20 percent curtailment. To the customer, the result is a significantly higher Effective $/MWh; however, this approach did succeed in shifting energy outside of a window of time when there was excess generation on the system and into a window when the utility likely does need firm power supply. While not economic for the customer at present, continued reductions in storage pricing and increases in efficiency could make this a viable option in the future.[21]

This structure, incorporating solar and storage together and responding to a set of firm price signals from the utility, is functionally similar to the announced project between Kauai Island Utility Cooperative (KIUC) and SolarCity. In that agreement, SolarCity is developing a 13-MW-ac solar project coupled with a 13-MW/52-MWh battery, which will be dispatched based on KIUC's preference. In its filing in support of this PPA, KIUC mentions intending to use 80-85 percent of the output to charge the battery so that it can be used for late afternoon ramping and evening peak shave purposes.[22] This same concept and structure could arise organically out of a ToD RFP, in which developers have the opportunity to identify unique engineering solutions to a specific utility problem statement.

III. Renewable Dispatchable Generation

One of the fundamental issues with resources such as solar or wind is that they are, at their current state, non-dispatchable. The final new contract option for consideration leverages an agreement structure that is prevalent for natural gas contracts and transfers it to the world of renewable resources in an effort to create dispatchability. This new structure converts the utility's role from a passive taker to a proactive asset manager.

In the world of natural gas generation, the tolling agreement is a structure in which the utility schedules in natural gas to the third-party-owned plant, providing a schedule for production.[23] The third-party's role is to guarantee a heat rate and availability for its plant. The utility pays the IPP a fixed capacity payment and then assumes all price volatility for the fuel.

Renewable Dispatchable Generation (RDG) takes a similar approach to dispatching generation; however, rather than basing the schedule and dispatch on the delivery of the fuel source under utility control, this structure schedules the *percentage of potential production* based on the solar or wind resource available on any given day, factoring in

[21] Based on modeling, the cost of lithium-ion batteries would need to decline by 32 percent from today's estimated levels for this approach to break even with the south-facing solar system modeled under the ToD structure.

[22] *See* Docket No. 2015-0331 application, filed September 10, 2015.

[23] While not currently used in Hawai'i, the tolling agreement is a relatively common contractual arrangement in other U.S. markets.

the needs of the system from both a cost and reliability standpoint. Under ideal circumstances the IPP would:

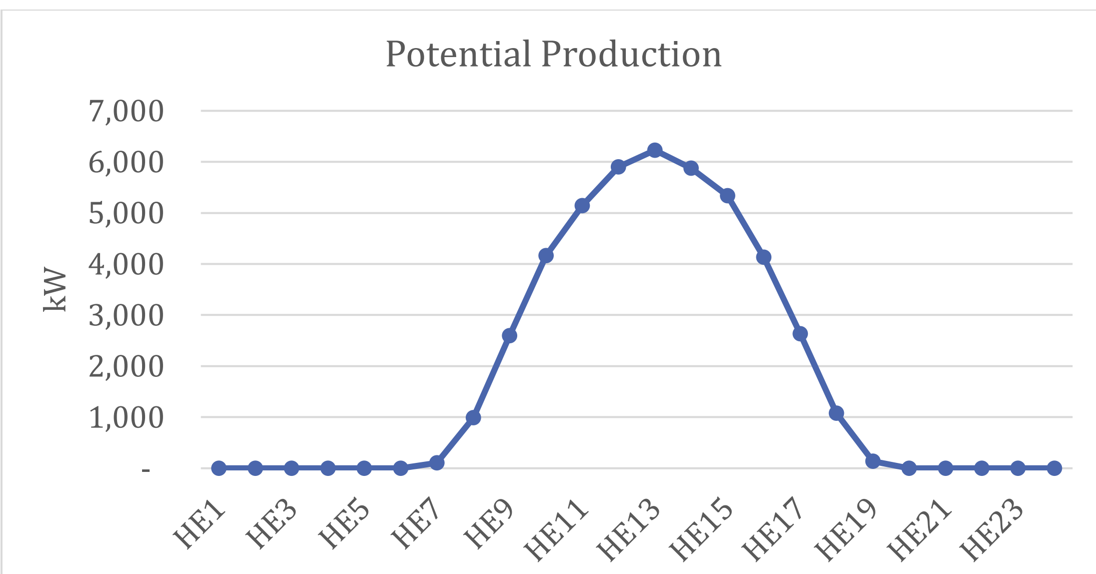
- Guarantee minimum availability metrics to ensure the equipment is maintained and available for production;
- Meet technical and operational characteristics which support grid operation, including voltage regulation, disturbance ride-through, frequency response, and active power control; and,
- Provide an indication to the utility of the available energy in the near real-time.

Similar to a tolling agreement for a conventional resource, these guarantees provide the basis for the energy production (MWh) expected for a given solar irradiance or wind speed. The utility, in turn, controls the output of the facility (both real and reactive power) on a real-time basis.

From an economic standpoint, the utility pays a fixed payment per month to ensure that the system is financeable and a variable $/MWh component to cover variable operations and maintenance (O&M) costs (if applicable, depending upon the resource). Any unscheduled energy, up to the amount capable of being produced given existing weather, becomes spinning reserves – unloaded generation that can be called upon in minutes – or is deployed automatically according to defined frequency response parameters, in a manner similar to conventional plant droop response.

For example, assume a solar plant with a nameplate capacity of 10 MW. Figure 7 depicts an average day's production curve for that plant.

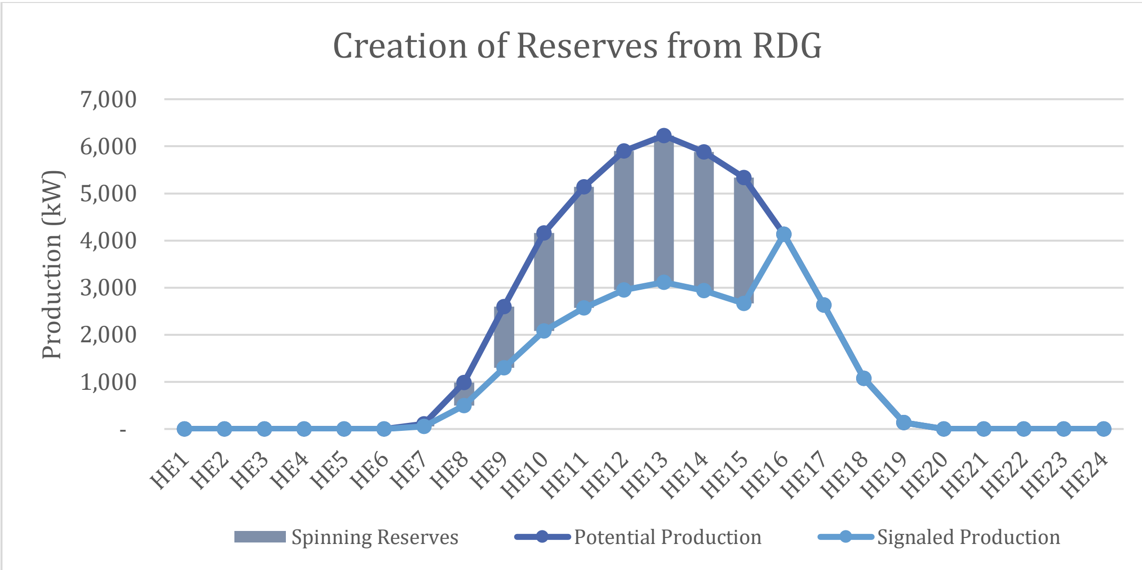
Figure 7 - Average Day Solar Production Curve



Source: SEPA & ScottMadden, 2016

Now assume that under the RDG structure, the utility intentionally dispatches the resource at 50 percent production. Later, due to a need to serve greater demand, the utility increases the production to 100 percent in the late afternoon.

Figure 8 - Potential Ancillary Services Created by Renewable Dispatchable Generation



Source: SEPA & ScottMadden, 2016

As shown in Figure 8, the ability to ramp up that solar asset created over 3 MW of upward spinning reserves on this average day, with over 2 MW of increased generation actually leveraged from 3-4pm. This resource can also provide downward spinning reserves during all producing hours. Alternatively, that same unloaded generation could be used for regulation purposes, with the inverter allowed to vary output based on the system frequency at any given moment. By purposefully under-scheduling the solar asset, the solar generator can contribute to the provision of ancillary services. Historically, variable renewables resources have not provided these types of grid services. Adding the ability to provide spinning reserves and frequency response reduces the integration costs of adding these assets to the system, effectively increasing their overall value to the Hawaiian Electric Companies. With a push towards a 100 percent clean energy future, these added capabilities may become critical to system reliability.

From a purely economic perspective, the RDG must be measured against both nominal impacts and net impacts after factoring in the benefits associated with the provision of ancillary services from the renewable resource. Using the approximated weighted average opportunity cost for the Kahe and Kalaeloa plants outlined in Table 5, a proxy value for spinning reserves and regulation services of $42/MWh is assumed for any synchronized, unloaded (rather than curtailed) generation from a RDG asset.[24] While increased unloaded generation results in a higher gross effective payment by customers, the ability to provide ancillary services from that facility provides a quantifiable value stream, creating a lower net effective price.[25]

Table 9 - Customer Economic Impacts of Renewable Dispatchable Generation

	Project NPV	Gross Effective $/MWh	Ancillary Services Impact	Net Effective $/MWh
Full Asset Utilization	$1.11 M	$100	$ -	$100
10% Unloaded		$112	($5)	$107
20% Unloaded		$126	($9)	$115
30% Unloaded		$144	($18)	$126

Source: SEPA & ScottMadden, 2016

From a financing perspective, the RDG provides guaranteed revenues (assuming the asset manager meets its minimum availability and energy production potential requirements), which should result in more certainty around debt service coverage and equity returns.

Challenges remain in transitioning directly to this new contract structure from today's paradigm. There will likely be several iterations related to resource forecasting and associated availability metrics, as well as additional operational challenges to overcome.

The idea of limiting the production from a renewable resource may seem counterintuitive – the energy produced is clean and lacks any real fuel dispatch cost. In Hawai'i, however, this may be the exact type of solution needed to help the state achieve its 100 percent renewable energy goal. At some point renewable, non-dispatchable resources will have to contribute ancillary services to support grid reliability.

Identifying Minimum Availability Metrics

For both the RDG and the Capacity & Energy PPA approaches, the concept of minimum availability metrics was broached. For these structures to succeed, the IPP must be contractually obligated to guarantee a specific availability for, and maintenance of, the equipment used to transform the raw renewable resource into energy. For the Capacity & Energy PPA, this obligation becomes the foundation of the monthly fixed payment for

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[24] Net Effective $/MWh = Delivered Energy x Gross Effective $/MWh + Ancillary Services Impact. Ancillary services impact is the levelized value of having the unloaded energy available for spinning reserves or regulation services.

[25] Because solar O&M costs tend to be more fixed/predictable in nature than variable costs, this example assumes that all costs are recovered via the fixed payment, with no variable payment included.

the resource. Failure to provide the capacity dictated in the agreement (with adjustments allowed for seasonal production differences and degradation) would result in IPP overpayment for the offered product. The RDG concept hinges on the ability to accurately predict potential renewable resource production at a given point in time, which becomes increasingly challenging as the forecast periods lengthens.

The agreed upon metrics for each of these structures may be different. In a contract that leverages the Capacity & Energy PPA structure, the peak hourly production each month is the basis of the capacity payment, and the minimum availability metric could be simply a monthly minimum MW guarantee for the plant's production (with adjustments annually for natural degradation). The fixed capacity payment would be reduced if the contracted capacity is not available. This simple structure allows for transparency between the utility and the IPP.

In an ideal RDG structure, the parties must be able to calculate resource availability based not only on equipment condition but also on the availability of the renewable resource at any given moment; to be clear, a challenge exists in gathering the necessary data. Therefore, a more formulaic approach becomes necessary. The parties must have a transparent and agreed upon approach to understanding what the production in any given hour should be so that the percentage dispatch can be calculated and tracked accordingly. One approach could be for the IPP to monitor the hourly solar radiation on site and guarantee a solar panel yield and performance ratio (covering losses, panel-specific shading, and any temperature adjustments necessary). The IPP would be required to provide equipment status as well as all telemetry required for the utility's energy forecasting purposes. Resource forecasting is performed today, and the same processes and calculations can become the foundation for codifying minimum availability metrics in the RDG contract.

Long-Term Impacts to Dispatch and Curtailment Order

Legacy renewable contracts have very stringent restrictions surrounding the ability to curtail those resources. Consequently, in Hawai‘i, curtailment order has been defined on a reverse-chronological basis, with the newest projects curtailed first, regardless of the relative costs or impacts to system reliability. As new contracts are executed and those legacy agreements term out, the curtailment order can be changed so it is based more closely on economics rather than execution date. For standard agreements, the PPA price is the most logical trigger for curtailment order, with flexibility outside of economic dispatch based on specific local system needs.

The same would hold true for the Capacity & Energy PPA structure. Contracts structured with a lower fixed cost and higher energy cost would be more likely to be curtailed. While this may motivate developers to bid high capacity costs and low energy costs, that approach may not align with how the Hawaiian Electric Companies value proposals in a competitive RFP process. However, placing the impetus on market players to determine how to best manage their risk surrounding curtailments should provide more certainty to the Hawaiian Electric Companies, as they pursue a least cost alternative for consumers.

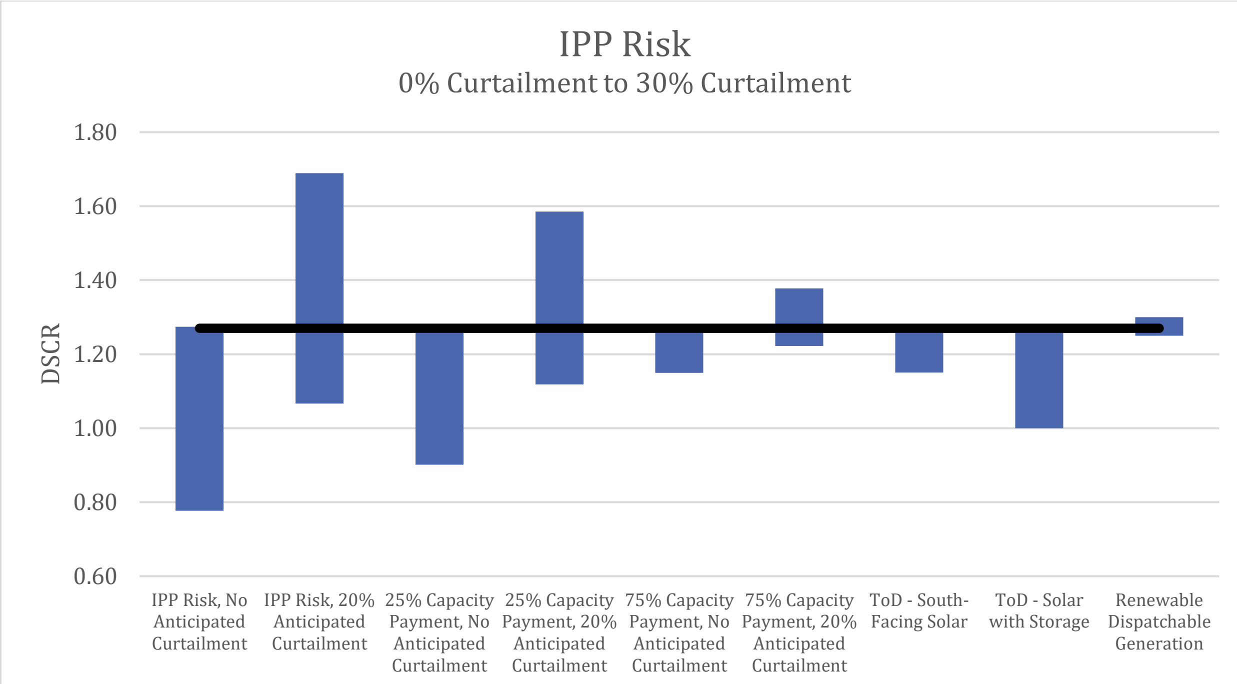
For the ToD Price Caps structure, curtailment would actually start with the lowest energy priced deal. This is because the price signals embedded in the contract already encourage energy production outside the most likely window of time that curtailments occur. Developers seek to maximize energy production outside of that timeframe and recognize contractually that production during those hours is at risk.

The RDG reframes the discussion on curtailment completely, as it is designed to provide system reliability services first and deliver energy second; the system operator has the ability to consider the most optimal dispatch of the system. Therefore, it is more appropriate to consider how that type of project fits into the economic dispatch stack. There may be many days of the year when that asset should produce power at 100 percent of its capability at an effective dispatch cost of $0/MWh, because all costs associated with the project are fixed in nature. Other times of the year, that asset should be dispatched at a much lower level (e.g., 50 percent of its potential) so that it has headroom to move up and down based on system needs or because there is insufficient demand for the energy.

Impacts to Debt Service Coverage

DSCR was chosen as a key metric because it can act as a proxy measure for the riskiness of a project. Curtailment has a direct impact on the perceived risk of a project to financiers, which can translate directly into a higher required DSCR for the project to move forward. For each of the scenarios contemplated in this report, the downside risk for IPPs is less than they currently experience under contracts in which they “own” all curtailment risk.

Figure 9 - DSCR @ Risk: 0% to 30% Actual Curtailment



Source: SEPA & ScottMadden, 2016

The range of possible DSCR values, based on the variety of curtailment scenarios modeled, narrowed considerably for several contract structures. The Capacity & Energy PPA structure provided less DSCR at risk for the scenario in which 25 percent of project costs were recovered via a fixed payment, with the 75 percent fixed payment structure providing significantly less variability overall. The RDG guaranteed the DSCR target was met because of the fixed nature of the revenues.

Next Steps

To start down this path to innovation, the following items are suggested for additional discussion and review. These and many other conversations will help better identify "win/win" solutions for Hawaiʻi.

Understanding Accounting Treatment

One issue that requires examination prior to transitioning to new contract structures is that, depending on the particulars of the agreement in question, utility accounting principles could require significantly different treatment of project costs. This is because certain PPAs could, for accounting purposes, be treated as a lease agreement. If the agreement is considered a capital lease under current accounting guidance (or simply a lease under ASU 2016-02), the utility must record a lease asset and a corresponding liability (i.e., lease obligation) on its financial statements. The lease obligation is considered a form of debt that results in the inclusion of additional leverage in the utility's capital structure. This negatively affects the utility's financial ratios. Under current accounting guidance, if the agreement is an operating lease, it is disclosed in the footnotes and not reported on the balance sheet.

Determination of whether a PPA constitutes an operating or capital lease is extremely contract-specific and project-specific, and two different solar assets could be classified differently based on their unique contractual terms and conditions. This determination is important, because the impact to the utility's financial statements from recognizing a project as a capital lease rather than an operating lease can be significant. Because recently revised accounting rules that will become effective in 2019 may increase this risk, this assessment is ongoing.

Updating Procurement Practices

Moving from concept to execution on any of the above ideas requires a reshaping of the procurement process from one driven predominantly by lowest price for delivered energy, to one that balances multiple pricing and delivery options against long-term price risk for consumers. For each of the structures identified, IPPs, regulators, utility companies, and other major stakeholders need to work together to determine how future RFPs can be designed so that: (1) IPPs have a clear picture of how projects will be valued; and (2) the Hawaiian Electric Companies can receive clear, transparent, and detailed information from IPPs to expedite the review process. These parties also need to agree on how to manifest these new ideas into contract language.

Leveraging New Technology

This report focuses on how to:

- Modify existing contract structures with developers to both lessen their risk to finance projects while also limiting the risk of severe price fluctuations to the end consumer; and,
- Reduce the constraints on the system operator to manage available resources according to their relative costs and reliability impacts on the system.

Other technologies, such as grid-facing solutions, that could meet similar end goals, were not examined here. One example to highlight is the integration of energy storage on a system level, rather than on a project level as contemplated in the ToD concept. Larger, centralized energy storage assets could help balance supply and demand more efficiently by storing solar generation for later dispatch. Storage could also be used to provide ancillary services. Indeed, the Hawaiian Electric Companies have already begun researching the potential for energy storage to provide synthetic inertia – near instantaneous response to frequency fluctuations. This and other applications for energy storage warrant further discussion and research, as the best solution for Hawai'i is most likely a holistic package of customer, developer, and utility investments that are collaboratively planned. These considerations and others can be part of a robust integrated resource planning process that weighs the relative pros and cons of different resources and contract structures for the benefit of all customers over the long term.

Conclusion

The procurement of incremental utility-scale renewable resources will be critical to meeting Hawai'i's energy future; however, those resources will be called upon to become increasingly more flexible as they comprise larger portions of the total energy portfolio. The question that must be answered is how to address the need for flexible, renewable generation while mitigating the potential costs to consumers. This requires PPA structures that:

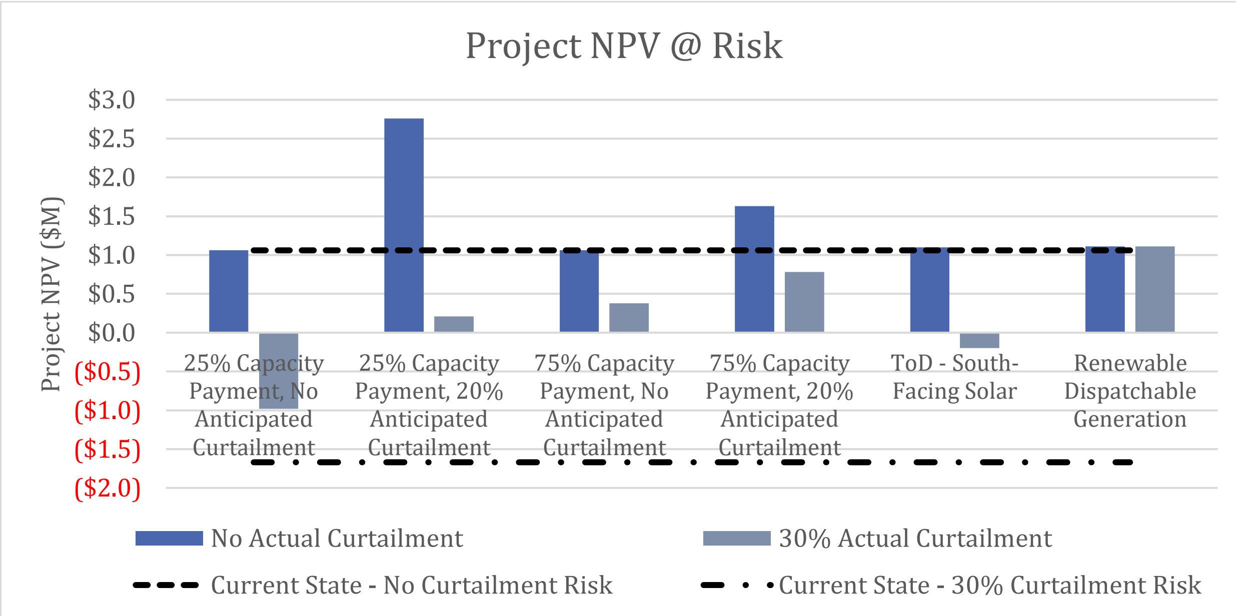
- Provide flexibility to adjust to the changing nature of the grid;
- Create adequate value to the developer;
- Deliver energy at a reasonable price for the utility; and,
- Meet the risk parameters amenable to regulators.

The goal of this report is to begin identifying new ways to contract for non-dispatchable renewable resources that meet each of these criteria; and with the complexities envisioned in the future, more than one alternative contract structure may be desired.

To varying degrees, both the Capacity & Energy and ToD contract structures shift the identification and quantification of curtailment risk away from the utility and onto the IPP. In this way, the development community can incorporate this major risk factor into how they structure proposals in future RFPs, creating the potential for the market to converge on a least-risk solution in a transparent manner. The RDG shifts the intent of contracting for utility-scale renewables away from an energy-only model and towards increasing system reliability while delivering clean energy. Large solar and wind projects mimicking the dispatchability of a conventional asset will be key in Hawai'i to achieve its vision of 100 percent renewable energy.

While the applicability of any of these proposed contract structures could vary depending on the type of project, location, and developer risk profile, understanding the impacts of curtailment across a variety of payment structures to the IPP's financing risk is important. The IPP's incorporation of that risk, driven by issues such as curtailment, will be directly reflected in the price the customer sees. This report considers both IPP and customer risk in an effort to identify "win-win" solutions for future PPA negotiations. The results of this analysis are summarized in the below graphics.

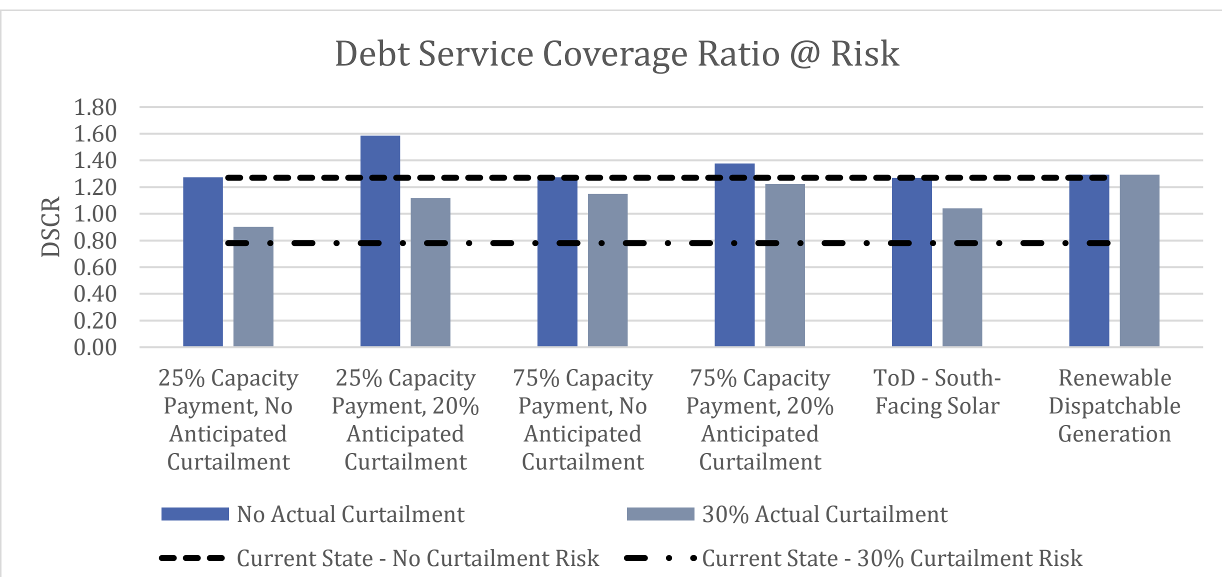
Figure 10 - Impact of New Structures on NPV @ Risk



Source: SEPA & ScottMadden, 2016

All identified contract structures have decreased NPV at risk for the IPP (*see* Figure 10). By agreeing to shift to any of these structures for new PPAs, the IPP can gain more confidence in cost recovery and their ability to earn their desired return on the project in question.

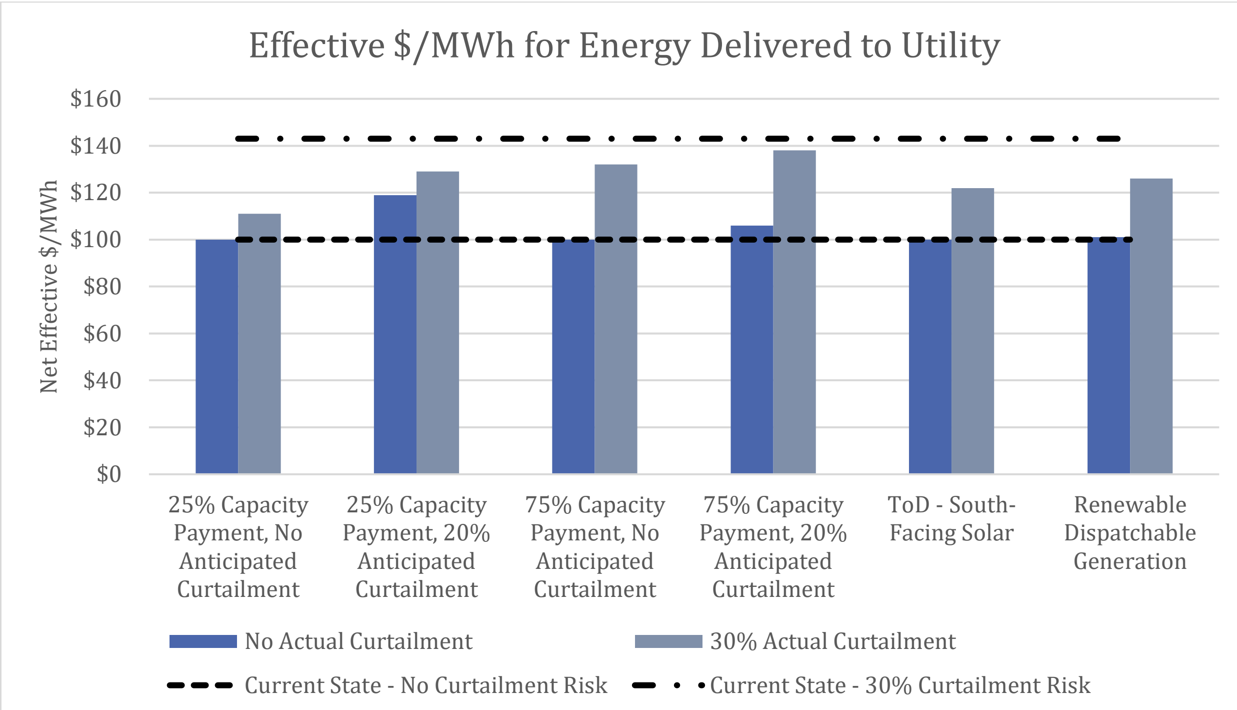
Figure 11 - Impact of New Structures on DSCR @ Risk



Source: SEPA & ScottMadden, 2016

All considered contract structures improved the project's DSCR compared to the current state approach with high curtailment risk, with all but one scenario resulting in a DSCR higher than 1.0 under 30 percent actual curtailment (*see* Figure 11). This provides further comfort for IPPs and their financiers when determining how curtailment will impact project cash flows.

Figure 12 - Impact of New Structures on Effective $/MWh for Energy Delivered to Utility



Source: SEPA & ScottMadden, 2016

All modeled contract structures resulted in lower Effective $/MWh for energy delivered, meaning the customer is better off even under high curtailment situations (*see* Figure 12).

By proactively identifying and allocating the risk of curtailed energy, it is possible to create contract structures for utility-scale renewable generation that result in net benefits for all parties. Taking advantage of these types of innovative contract structures in Hawai'i can lead to better integration of utility-scale projects that are both cost-effective and have the ability to support system reliability as the state moves towards 100 percent clean energy.

Table of Acronyms

BESS: Battery Energy Storage System

CEP: Curtailed Energy Price

DA: Day Ahead

DEP: Delivered Energy Price

DER: Distributed Energy Resources

DSCR: Debt Service Coverage Ratio

EIA: Energy Information Administration

ERCOT: Electric Reliability Council of Texas

GE: General Electric

HA: Hour Ahead

HNEI: Hawai‘i Natural Energy Institute

IPP: Independent Power Producer

ISO: Independent System Operator

KIUC: Kauai Island Utility Cooperative

kW: Kilowatt

MW: Megawatt

MWh: Megawatthour

NEM: Net Energy Metering

NREL: National Renewable Energy Laboratory

NPV: Net Present Value

O&M: Operations and Maintenance

PPA: Power Purchase Agreement

PV: Photovoltaic

RDG: Renewable Dispatchable Generation

RFP: Request for Proposals

RTO: Regional Transmission Organization

SDC: System Decremental Cost

SEPA: Smart Electric Power Alliance

ToD: Time-of-Day

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Appendix A: Additional Models Considered

Table 10 - Additional Contractual Models Considered

Solution	Description	Potential Implications
DEP / CEP PPAs	○ Require bidders to provide a Delivered Energy Price (DEP) and a Curtailed Energy Price (CEP), both in $/MWh ○ No floor or cap imposed on CEP pricing ○ Could allow for tiered CEP pricing ○ Curtailed energy compensated at CEP	○ Bidders can price their risk outlook into the breakout in payment streams, but not likely to result in major cost savings
Curtailment Bank	○ For any curtailed energy that is paid for by the utility, the same amount of energy must be delivered after the end of the base contract term	○ Proposed unsuccessfully in recent PPAs
BESS for Curtailment	○ Require Battery Energy Storage Systems (BESS) at all new non-dispatchable resources ○ BESS is sized to meet a minimum curtailment window of storage ○ Curtailment beyond BESS sizing paid at a predetermined rate	○ Deploying BESS strictly for curtailment is unlikely to be cost-effective; would need to incorporate additional BESS value streams like smoothing, frequency control, etc.
Rotating Monthly Bands	○ Create monthly min/max bands for PPAs, where the bands differ based on anticipated curtailment issues in those months ○ Each new PPA is treated uniquely for the bands, allowing for the potential to rotate which months are most curtailable at each	○ Creates opportunity for curtailment diversity among projects
SDC Curtailment	○ For any curtailed energy, the utility pays the developer their System Decremental Cost (SDC) rather than the PPA stipulated price ○ SDC would be calculated based on a cost-based rate formula that would be approved and routinely updated	○ Aligns cost borne by ratepayers with a measure more akin to the value of that decremental energy ○ Unknown SDC introduces additional risk for the IPP
Pro Rata Decrease	○ When curtailment is required, all applicable projects are required to back down at the same percentage so that, in total, the needed curtailment is met	○ May limit the magnitude of an individual IPP's curtailment risk, but may not reduce the nominal risk across an individual island for those customers

Source: SEPA & ScottMadden, 2016