Best Practices to Value Benefits of Renewable Energy Development in Hawai'i

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by Joel N. Swisher, PhD, PE

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Policies, programs, and investments to support renewable energy sources that lead to Hawai'i 's energy independence have been a major priority for the Forum. This concern and seeing the challenges and opportunities facing Hawai'i, the Forum sought to study the benefits in addition to the costs of renewables – to find a framework for assessing and prioritizing renewables; and, in particular, to seek best practices from other jurisdictions for the metrics to assess and determine Hawai'i's renewable resources portfolio.

With the support and funding of Ulupono Initiative, the Forum contracted with Dr. Joel Swisher, Director for the Institute for Energy Studies, Western Washington University, who has over 30 years experience in many aspects of clean energy technology, including energy system analysis and integration, and electric utility resource planning and economics. We asked him to assess and determine best practices and methodologies for assessing the economic value of renewable energy produced in Hawai'i. The study is a review of the academic and trade literature as well as efforts of other jurisdictions.

While the Forum sought to come up with an analytical framework for evaluating the costs and benefits of renewable resources available to Hawai'i, the study instead focuses on valuing benefits, which has heretofore been neglected in the analyses. It thus adds a fuller consideration of the value of renewables. The costs of renewables will be covered in other arenas, e.g. the current discussion before the Public Utilities Commission, but this study provides some background and focuses thoughtful consideration on the value of renewables. What Dr. Swisher found was that no existing model is a complete fit in Hawai'i. Rather, elements of some existing models, expanded and adapted to the Hawaiian context, would be needed. Hawai'i is at the cutting edge in terms of its high penetration of renewable energy, driving wholesale changes in energy supply systems, rather than marginal changes as in most other jurisdictions. The Forum therefore encourages further discussion and support for developing the metrics for valuing the benefits of renewables.

We thank those who contributed to this study, in particular, Ulupono Initiative and Hawai'i Community Foundation, for its funding support for the study; and to the many individuals and organizations who provided their input and guidance.

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Executive Summary

What is renewable energy worth in Hawai'i? More specifically, if owners of renewable energy production in Hawai'i were paid for the benefits that renewable energy brings, by replacing the use of fossil fuels in Hawai'i, how should the value of such benefits be calculated? This approach would be a departure from, for example, net energy metering – based on the retail energy tariff, or feed-in tariffs – based on cost of renewable source.

Instead, payment on the basis of the benefits of renewable fuels and electricity requires a valuation methodology that captures the full value of using renewable energy to replace fossil fuels. The methodology should be comprehensive, logically and theoretically consistent, practical to use, and applicable to Hawai'i. Initial efforts to value the benefits of renewables in energy tariff design were conducted in support of recent "value of solar" tariffs for mainland utilities with significant differences from the Hawaiian context.

While the simplest approach to valuation might be to consider only today's value of the fossil fuel avoided by using renewable energy, a comprehensive approach to valuing the benefits of renewables covers the lifetime of the renewable energy investment and should consider multiple benefits. Some categories of benefits that represent important sources of value are difficult to quantify accurately, and are typically omitted. Thus, achieving a comprehensive valuation might require compromises in achieving maximum precision.

The application of renewable energy benefit values to renewable electricity tariffs, for example, would fit the model of a two-part tariff. The basic formula is that the renewable energy owner is paid for power produced, based on its benefits, and pays for on-site consumption at the default retail rate. This approach is used, for example, in "value of solar" tariff methods developed by Austin Energy in Texas and the state of Minnesota.

Based on a review of the existing literature on avoided costs of renewable energy, i.e., the avoided cost of fossil fuel replaced by renewable fuels and the marginal cost of the power generation and delivery replaced or deferred by renewables, the following categories of renewable energy benefits appear to be most relevant in the Hawaiian context:

Benefits of renewable fuels:

- Avoided fossil fuel costs
- Fossil fuel price risk hedging value
- Emission reductions

Benefits of renewable electricity generation:

- Electric energy-related benefits
  - Avoided fossil fuel costs
  - Fossil fuel price risk hedging value
  - Emission reductions
  - Avoided energy losses

- Electric-capacity-related benefits
    - Avoided system capacity costs

Other benefits (could apply to either renewable fuels or electric generation):
    - Local economic development, with considerable methodological work

All of the categories of benefits do not necessarily apply to all renewable energy sources. Fuel energy-related benefits apply to all the technologies, as they represent the sum total of renewable fuel benefits, and they appear to be the most important component of the renewable electricity benefits. In the Hawaiian context, electric capacity-related benefits appear less important.

Note, however, that the role of generation capacity could change in Hawai'i in the near future. Growing renewable penetration will initially trigger some rate of curtailment. As system planning responds to the need to integrate more renewable sources, capacity resources will necessarily become more flexible, providing a wider range of peaking, ramping and ancillary service needs. Some of these services will be supplied by renewable sources, demand-side resources like demand response, and energy storage.

With regard to the valuation of renewable energy benefits, the Hawaiian context presents unique challenges. Existing methodologies, developed mostly for mainland utilities, generally assume that renewable energy causes a small, marginal displacement of existing supply sources in the short term, and potentially a marginal change or deferral of the reference case resource plan in the longer term. Wholesale change, beyond such marginal effects, is not readily captured in existing methods.

With these challenges in mind, one could assemble a comprehensive methodology to value renewable energy benefits in Hawai'i, by building on existing methods and adapting them to Hawai'i. The following actions are recommended for HEPF and its colleagues to accomplish the needed adaptation of renewable valuation methods:

Fuel energy-related benefits (of renewable fuels and renewable electricity):

- Avoided fossil fuel costs: use the levelized value of forecasted fuel cost, over the life of the renewable energy technology
- Fossil fuel price risk hedging value: use the fuel price premium indicated by long-term hedge quotes for 10-, 15- or 20-year supply contracts, solicited from fossil fuel suppliers or financial intermediaries. If such market price data are not available, use Monte Carlo analysis of fuel price trajectories.
- Emission reductions: use the levelized value of forecasted CO2 emission cost, over the life of the renewable energy technology. In the years before carbon prices are in force, HEPF could agree on a reasonable proxy, e.g., the median of prices in existing markets, which now in include California and RGGI in the northeast.

Electric energy-related benefits (of renewable electricity only):

- Avoided electric energy cost: use the full avoided fuel costs (the sum of the three categories of fuel energy-related benefits, above), which is multiplied by the

marginal generation heat rate, to calculate avoided electric energy cost, on an hourly basis over the life of the renewable generation investment.

- Marginal generation heat rate: The recommended approach is to adopt the model framework of the avoided cost model developed for the PUC by E3, for baseline scenarios and method for hourly determination of marginal generation sources, and to adjust its assumptions for fuel price, emissions, hedge value, etc.
- Inputs to simulated dispatch of the planned generation fleet (using a modified PUC/E3 avoided model or other model): HEPF, in collaboration with the PUC, could agree on a consensus, reference-case resource plan, which would provide a stable set of generation capacity and fuel input assumptions.
- Avoided energy losses, for distributed sources (downstream of the T&D grid) only: use the average T&D loss rate, applied to the avoided electric energy cost

Electric capacity-related benefits (of renewable electricity only):

- Marginal cost of capacity: use the levelized value of the capital cost, plus the marginal operation and maintenance (O&M) cost, for the incremental generation capacity resource(s) and associated transmission, needed to meet load growth.
- Incremental generation capacity resource: HEPF, in collaboration with the PUC, could agree on a consensus, reference-case resource plan, which would provide a stable definition of incremental planned generation capacity expansion, if any.
- Avoided capacity cost: use the effective load-carrying capacity (ELCC), multiplied by the marginal cost of capacity. HEPF could review and update utility estimates of ELCC for each island, based on consensus data inputs.
- Distribution capacity, ancillary services, etc.: existing methods for valuing these distributed benefits appear unlikely to produce significant, positive results when applied in the Hawaiian context.

Other benefits (could apply to either renewable fuels or electric generation):

- Local economic development: it is recommended that methodological development focus on producing a reasonable, albeit uncertain, estimate of the local economic development benefit of renewable energy.
- Define the economic development metric: one can consider net economic output, incremental gross state product, net labor income, tax revenue or other values.
- Drivers of economic development benefit: use the renewable energy investment, the saved fossil fuel cost, and the net change in customer energy expenditure.
- Local economic multipliers: for each of the three cost drivers above, derive local multipliers for the ratio of the selected economic development benefit to the cost driver. HEPF could convene local economic modeling experts, such as those at UHERO, to explore extracting these multipliers from statewide input-output models, or possibly general equilibrium models, specific to Hawai'i.

Summary and Recommendations

This report is intended to help the Hawai'i Energy Policy Forum to support integration of renewable energy into the Hawaiian fuel supply and electric grid by identifying, assessing and recommending best practices for valuing the benefits of renewable fuels and renewable electricity. The simplest approach to valuation might be to consider only today's value of the fossil fuel avoided by using renewable energy. In contrast, a comprehensive approach to valuing the benefits of renewables covers the lifetime of the renewable energy investment and should consider multiple benefits, including:

Potential benefits of renewable fuels:

- Fuel energy-related benefits: fuel cost savings, fuel price risk hedging, emission reductions

Potential benefits of renewable electricity generation:

- Electric energy-related benefits: avoided energy losses, fuel cost savings, fuel price risk hedging, emission reductions
- Electric capacity-related benefits: avoided generation and transmission capacity costs, distribution capacity costs, capacity value of avoided losses, ancillary services

Other potential benefits (could apply to either renewable fuels or electric generation):

- Local economic development, security-related benefits

The framework of this report first considers the benefits of renewable fuels such as biomass, biogas, and biodiesel. These benefits are the "fuel energy-related benefits," because the benefits are proportional to the delivered energy content of renewable fuel that replaces fossil fuel.[1] A comprehensive approach to valuing the benefits of renewable fuels should include each of the categories of fuel energy-related benefits.

The benefits of renewable electric generation also include fuel energy-related benefits, the value of which also depend on the efficiency, or heat rate, associated with fossil fuel-fired generation that renewables replace.[2] In addition, "electric energy-related benefits" might also include the value of avoided grid losses, for certain distributed generation sources that can be sited downstream from the transmission and distribution (T&D) grid.

The full value of renewable electricity benefits is the sum of electric energy-related benefits and any "electric capacity-related benefits" that apply to a specific type of renewable generation source. The value of capacity-related benefits depends on the degree to which a renewable source can offset electric supply capacity, generally during times of peak load.

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[1] In million British thermal units, MMBtu, or gigajoules (GJ) of fuel energy.

[2] Heat rate is typically measures as fuel input in MMBtu per MWh of generation, which is actually the reciprocal of efficiency, i.e., lower heat rates indicate higher efficiency.

Based on a review of the existing literature on avoided costs of renewable energy, i.e., the avoided cost of fossil fuel replaced by biofuels and the marginal cost of the power generation and delivery replaced or deferred by renewables, and initial efforts to value the benefits of renewables in energy tariff design, such as recent "value of solar" tariffs, the following categories of renewable energy benefits appear to be most relevant in the Hawaiian context:

Benefits of renewable fuels:

- Avoided fossil fuel costs
- Fossil fuel price risk hedging value
- Emission reductions

Benefits of renewable electricity generation:

- Electric energy-related benefits
  - Avoided fossil fuel costs
  - Fossil fuel price risk hedging value
  - Emission reductions
  - Avoided energy losses
- Electric-capacity-related benefits
  - Avoided system capacity costs

Other benefits (could apply to either renewable fuels or electric generation):

- Local economic development, with considerable methodological work

Recommended methods for valuing each of the above categories, all of which are explained in detail in the main body of this report, are as follows:

Fuel energy-related benefits (of renewable fuels and renewable electricity):

- Avoided fossil fuel costs: use the levelized value of forecasted fuel cost, over the life of the renewable energy technology.

- Fossil fuel price risk hedging value: use the fuel price premium indicated by long-term hedge quotes for 10-, 15- or 20-year supply contracts, solicited from fossil fuel suppliers or financial intermediaries. If such market price data are not available, use Monte Carlo analysis of fuel price trajectories.

- Emission reductions: use the levelized value of forecasted CO2 emission cost, over the life of the renewable energy technology. In the years before carbon prices are in force, HEPF could agree on a reasonable proxy, e.g., the median of prices in existing markets, which now in include California and RGGI in the northeast.

Avoided fossil fuel cost is typically the most important component in the valuation of benefits of renewable electricity, and it is the sum total of renewable fuel benefits. Some categories of energy-related benefits, such as fuel price hedge value and emission reductions, appear to be important sources of value that are typically omitted, due to the difficulty of quantifying them accurately. Omitting these categories of benefits, however, would implicitly treat their value as zero for 20+ years, a clearly unreasonable result.

Thus, achieving the goal of comprehensive valuation might require compromises in the valuation methods' accuracy, to pursue reasonable, if imprecise, non-zero estimates. Estimation of fuel price hedge value should be explored via long-term future supply contracts or, alternatively, Monte Carlo models. Emissions can be included via carbon market proxy, as the value of CO2 emissions tends to dominate emission valuations.

Electric energy-related benefits (of renewable electricity only):

- Avoided electric energy cost: use the full avoided fuel costs (the sum of the three categories of fuel energy-related benefits, above), which is multiplied by the marginal generation heat rate, to calculate avoided electric energy cost, on an hourly basis over the life of the renewable generation investment.

- Marginal generation heat rate: The recommended approach is to adopt the model framework of the avoided cost model developed for the PUC by E3, for baseline scenarios and method for hourly determination of marginal generation sources, and to adjust its assumptions for fuel price, emissions, hedge value, etc.

- Inputs to simulated dispatch of the planned generation fleet (using a modified PUC/E3 avoided model or other model): HEPF, in collaboration with the PUC, could agree on a consensus, reference-case resource plan, which would provide a stable set of generation capacity and fuel input assumptions.

- Avoided energy losses, for distributed sources (downstream of the T&D grid) only: use the average T&D loss rate, applied to the avoided electric energy cost.

Electric energy-related benefits can be estimated by applying best-practice methods from mainland utilities, although their relevance will be limited as Hawai'i pursues higher renewable production levels and adjusts its future resource planning accordingly. As the renewable penetration grows, it increases the risk of curtailment of renewable sources. With renewables as the marginal source during some hours, avoided energy cost is zero.

The process of converting avoided fuel costs to avoided electric energy costs requires identification of marginal generation sources and their heat rate, fuel cost and carbon content. Existing tools offer a practical approach for this task in Hawai'i. For example, adopting the framework of the avoided cost model developed for the Hawai'i PUC could provide a model of the baseline supply scenarios and hourly determination of marginal

generation sources. It should be feasible to build an open process to adjust assumptions for fuel prices, emissions, hedge value, etc., while protecting any proprietary data.

Electric capacity-related benefits (of renewable electricity only):

- Marginal cost of capacity: use the levelized value of the capital cost, plus the marginal operation and maintenance (O&M) cost, for the incremental generation capacity resource(s) and associated transmission, needed to meet load growth.

- Incremental generation capacity resource: HEPF, in collaboration with the PUC, could agree on a consensus, reference-case resource plan, which would provide a stable definition of incremental planned generation capacity expansion, if any.

- Avoided capacity cost: use the effective load-carrying capacity (ELCC), multiplied by the marginal cost of capacity. HEPF could review and update utility estimates of ELCC for each island, based on consensus data inputs.

- Distribution capacity, ancillary services, etc.: existing methods for valuing these distributed benefits appear unlikely to produce significant, positive results when applied in the Hawaiian context. New technical work to resolve the engineering and cost implications of grid management with higher penetration of renewable sources may reveal useful insights, but results are likely to be highly site-specific.

In Hawai'i, with modest load growth, high fuel prices, and evening demand peaks, avoided capacity costs appear unlikely to contribute a large component of the economic benefit of renewable energy. Rather, avoided energy-related costs are likely to dominate. However, some renewable generation options, such as baseload or dispatchable biomass-fired power on Oahu, could have a significant capacity-related benefit.

To construct stable estimates of renewable energy benefits, one needs a stable reference-case resource plan. The risk of increasing renewable curtailment and the future prospect of replacing oil-fired generation with LNG make today's reference-case resource plans less certain. Thus, a potentially helpful result of on-going integrated resource planning and PSIP processes would be to converge on consensus, reference-case plans that the HEPF could endorse. Its generation capacity and fuel assumptions could provide a more confident basis on which to estimate avoided costs and benefits of renewable generation.

Several categories of potential distribution-level benefits – namely marginal distribution capacity costs, capacity value of avoided losses, and ancillary services – appear to be either unlikely to indicate significant benefit values, or are relatively uncertain and difficult to value. In particular, this uncertainty appears large, relative to the likely range of benefit values, which diminishes the need to include these categories in the valuation.

Other benefits (could apply to either renewable fuels or electric generation):

- Local economic development: it is recommended that methodological development focus on producing a reasonable, albeit uncertain, estimate of the local economic development benefit of renewable energy.

- Define the economic development metric: one can consider net economic output, incremental gross state product, net labor income, tax revenue or other values.

- Drivers of economic development benefit: use the renewable energy investment, the saved fossil fuel cost, and the net change in customer energy expenditure.

- Local economic multipliers: for each of the three cost drivers above, derive local multipliers for the ratio of the selected economic development benefit to the cost driver. HEPF could convene local economic modeling experts, such as those at UHERO, to explore extracting these multipliers from statewide input-output models, or possibly general equilibrium models, specific to Hawai'i.

Among the other, relatively novel, categories of benefits, local economic development benefits have potential to be quantified and could indicate a significant benefit value. More research and methodology development are needed to define the appropriate metric and to adapt economic modeling results to the rough quantification of a benefit than can be attributed to renewable energy. On the other hand, security-related benefits appear to be too uncertain and difficult to define and quantify with currently available methods.

Table S-1. Applicability of renewable energy benefits by technology

Benefit category	**Biofuels for transport**	**Distributed solar PV**	**Central solar PV or CSP**	**Wind**	**Hydro (run-of-river)**	**Geo-thermal**	**Biofuel – fired power generation**	**Distributed generation from biofuel**
Fuel cost	√	√	√	√	√	√	√	√
Hedge value	√	√	√	√	√	√	√	√
Emissions	√	√	√	√	√	√	√ & biogas may have CH4 benefit	√
Energy losses	n/a	√						√
Generation, transmission system capacity	n/a	minimal as the net load peak moves later in the evening	Minimal, √ for CSP + thermal storage	√ for a portfolio of sources	√ for a portfolio of sources	√	√	√
Distribution capacity, ancillary serv.	n/a	minimal, maybe zero or negative						depends on location, operation
Economic development	?	?	?	?	?	?	?	?

All of the categories of benefits do not necessarily apply to all renewable energy sources. Table S-1 summarizes the general correspondence between the benefit categories and the main renewable fuel and electric generation technologies. Fuel energy-related benefits apply to all the technologies, as they represent the sum total of renewable fuel benefits, and they appear to be the most important component of the renewable electricity benefits.

In the Hawaiian context, electric capacity-related benefits appear less important, based on low estimates of ELCC values for solar and wind in particular. The benefit of avoided energy losses only applies to distributed sources, downstream of the T&D grid. Values of other distributed benefits, such as distribution capacity, ancillary services, etc., only apply to distributed sources, and are further limited by low ELCC values.

As noted above, however, the role of generation capacity could change in Hawai'i in the near future. Growing renewable penetration will initially trigger some rate of curtailment. As system planning responds to the need to integrate more renewable sources, capacity resources will necessarily become more flexible, providing a wider range of peaking, ramping and ancillary service needs. Some of these services will be supplied by renewable sources, demand-side resources like demand response, and energy storage.

This future of enhanced flexibility will challenge and probably confound some of the existing valuation methods covered in this report, as the very definition of capacity may change. On the other hand, the flexibility provided by fast-ramping generation, demand response, plug-in vehicles and energy storage will moderate the need to curtail renewable sources as their penetration grows, thus enhancing their value based on today's metrics.

With regard to the valuation of renewable energy benefits, the Hawaiian context presents unique challenges. Existing methodologies, developed mostly for mainland utilities, generally assume that renewable energy causes a small, marginal displacement of existing supply sources in the short term, and potentially a marginal change or deferral of the reference case resource plan in the longer term. Wholesale change, beyond such marginal effects, is not readily captured in existing methods.

Figure 1 compares the range of benefit values for the main categories of renewable electric energy benefits, as catalogued in a meta-study by Rocky Mountain Institute (RMI),[3] with an approximate range of energy-related benefits in Hawai'i. The Hawaiian costs are far higher, due to the high fuel costs associated with oil-fired power generation.

Accordingly, one can project that the avoided fuel-related costs from mainland utilities, as reported by RMI, would be higher in Hawai'i, for categories such as fuel, hedge value and losses. Other categories would not necessarily be higher in Hawai'i and, for distribution-level benefits like distribution capacity and ancillary services, could be lower. From this perspective, the avoided energy-related costs clearly appear to dominate

[3] Rocky Mountain Institute (RMI), 2013. A Review of Solar PV Benefit & Cost Studies, http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue

the valuation of renewable electricity benefits, with a possible contribution from generation capacity in the case of baseload or dispatchable renewable sources.

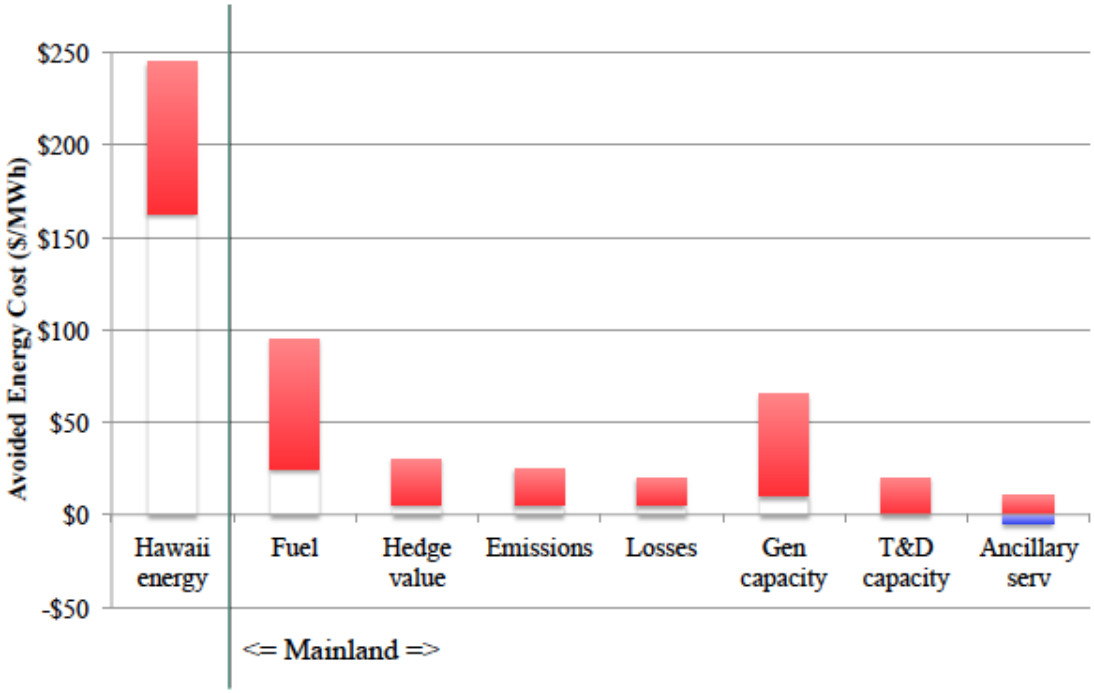

Figure 1. Range of mainland utilities' renewable benefit values, compared to range of Hawai'i avoided energy-related costs. Source: Rocky Mountain Institute 2013.

The application of renewable energy benefit values to renewable electricity tariffs, for example as an alternative to net energy metering, would fit the model of the two-part tariff. The basic formula is that the renewable energy owner is paid for power produced according to its benefits, and on-site consumption is billed at the default retail rate. This approach is used, for example, in "value of solar" tariff methods developed by Austin Energy in Texas and the state of Minnesota.

Because the energy- and capacity-related benefits of renewable energy vary over time, it might be appropriate to apply a time-varying tariff to capture these variations, for example in customer segments where advanced metering is feasible. If a time-varying valuation formula is used, it should be designed to be stable and predictable over the renewable energy investment time horizon. A renewable tariff that is adjusted over time, for example according to an index of future fuel prices, would be less predictable than traditional tariff terms, and could increase financial risk.

An alternative to time-varying tariffs to capture capacity-related value would be separate payment for energy and capacity. This approach could be relevant for distributed solar combined with demand response or demand-side energy storage. Given low ELCC values for distributed solar in Hawai'i, most of a combined system's capacity value would come from the demand-side resource. Thus, separate valuation could be the simplest method.

Introduction

Comprehensive and accurate evaluation of the costs and benefits of renewable energy is a useful tool for prioritizing investments in renewable generation and other energy resources. Some utilities and state regulators have applied estimates of the benefits of renewable energy and energy efficiency in utility planning and procurement procedures. For example, in 2003 the California Public Utilities Commission (PUC) commissioned the development of a formal procedure to estimate comprehensive avoided costs for efficiency programs. The resulting methodology clarified utility targets under the state's policy to capture all cost-effective efficiency resources, and parts have also been applied to utility procurement of renewable energy.

Procurement of customer-sited renewable generation has mostly not been based on payment for benefits of renewable energy. Rather, in the U.S., the energy metering (NEM) tariffs have been based on retail utility rates. Resulting in a somewhat arbitrary level of subsidy on most mainland systems. Elsewhere, especially in Europe, feed-in tariffs (FIT) have been based on costs, rather than benefits, of renewable energy. Both NEM and FIT tariffs have been based on a policy goal of subsidizing the development of renewable sources, rather than payment for their benefits.

Today, in Hawai'i and other jurisdictions where the contribution of customer-sited renewable generation has reached 10% or more of circuit loads, alternatives to a simple NEM tariff are increasingly relevant. Such alternatives include "value of solar" rates and other types of two-way tariff structures, in which energy flows to and from the customer are valued individually. Since the value of renewable generation is based on the benefits it delivers, this approach requires a balanced and realistic valuation of the benefits.

The benefits of renewable energy are often underestimated by considering only the resulting fuel cost savings at current prices. A more comprehensive approach to valuing the benefits of renewables should consider the full avoided costs of utility power supply, as well as other categories of economic, social and environmental benefits that can be quantified using available data.

Note that expanding the method for the valuation of benefits, to be more comprehensive, leads to tension with the goal of accuracy. Some categories of benefits, such as fuel price hedge value and reduction of presently unregulated emissions, appear to be important sources of value that are typically omitted, due to the difficulty of quantifying them accurately. Thus, achieving the goal of comprehensive valuation might require compromises in achieving the goal of accuracy.

This study reviews existing work on the valuation of renewable and distributed energy, avoided costs, etc., to identify and prioritize categories of renewable energy benefits (energy, capacity and other) that are most relevant and important in the Hawaiian context.

The objective here is not to debate the merits of this approach to valuation against those of NEM or FIT methods as policy tools.

Rather, the goal is to recommend to the Hawai'i Energy Policy Forum the best-practice methodologies to quantify renewable energy benefits, and to begin a discussion regarding their potential application to renewable energy production in Hawai'i, while observing remaining methodological gaps. In particular, as discussed below, the high penetration of renewables in small, isolated power systems in Hawai'i tends to increase uncertainty in the definition of marginal resources, which limits the applicability of existing valuation methodologies that are based on stable cost structures assumed for mainland utilities.

Background: Existing Literature on Renewable Benefits and Avoided Costs

Research and analysis of the benefits and avoided costs of renewable and distributed resources has developed over more than 20 years. Early work showed the increased value of distributed renewables, based specifically on the area- and time-specific avoided costs of distribution capacity.[4] This work was applied to demand-side management,[5] as well as to distributed renewables in Brazil and the Philippines.[6]

The idea that distributed resources, including renewables and other technologies such as fuel cell cogeneration, had inherent value in the utility system was cataloged by Rocky Mountain Institute (RMI), in voluminous detail[7] and more accessible form.[8] The most quantifiable benefits identified in these studies were based on avoided distribution costs, ancillary services and reliability benefits, which depended heavily on the degree to which distributed sources could provide capacity value in the system in question.

Avoided cost is defined as the marginal cost of the same amount of energy acquired through another means such as the construction and operation of new generation and delivery, or purchase from an alternate supplier. Avoided cost is essentially the mirror image of the long-run marginal cost of power supply. While marginal cost indicates the cost of the *next* unit of supply, avoided cost is the savings from avoiding the *last* unit.

As such, avoided costs include energy costs, such as fuel and emissions, and capacity costs, such as generation and distribution. The avoided cost of a resource like renewable

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[4] Orans, R., 1989. Area-Specific Marginal Costing for Electric Utilities: A Case Study of Transmission and Distribution Costs, PhD Thesis, Stanford University.
[5] Orans, R., C.K. Woo, J. Swisher, 1992. Targeting DSM for Transmission and Distribution Benefits, Electric Power Research Institute, EPRI TR-100487.
[6] Swisher, J., 1998. *Using Area-Specific Cost Analysis to Identify Low Incremental-Cost Renewable Energy Options*, Global Environment Facility.
[7] Lovins, A., et. al., 2002. Small Is Profitable, http://www.rmi.org/Knowledge-Center/Library/U01-13_SmallIsProfitable
[8] Swisher, J., 2002. Cleaner Energy, Greener Profits: Fuel Cells as Cost-Effective Distributed Energy Resources, http://www.rmi.org/Knowledge-Center/Library/U02-02_CleanerEnergyGreenerProfits

generation includes each of these terms, to the extent that the resource is able to avoid, i.e., replace or defer, the energy or capacity otherwise supplied by the marginal resource.

The idea of avoided costs as an indication of the value of alternative energy resources arose from the Public Utilities Regulatory Policy Act (PURPA) of 1978, which established the criterion that non-utility generation sources such as co-generation should be valued at the utility's full *avoided cost.* When this criterion was applied, with a rather generous interpretation, to wind power in California during the 1980s, it triggered the first (temporary) boom in renewable energy development, after which avoided costs were interpreted in a more limited manner.

New avoided cost methodologies have been formalized and now cover several of the relevant categories of renewable energy benefits. These methods have been most fully developed and formalized by Energy and Environmental Economics (E3), who recently developed an avoided cost model for Hawai'i PUC. Earlier E3 work on avoided costs of energy efficiency, for the California PUC, set precedents for the inclusion as avoided costs of new categories of benefits that had previously been treated as externalities or not quantifiable, including costs of air pollution and greenhouse gases (GHGs).[9] Today, E3 models are used as default avoided cost calculators for several California programs.

Recently, a large number of studies have addressed the benefits of distributed solar in the U.S., each with a slightly different methodology and menu of avoided costs or other benefit categories. Informative meta-studies by the National Renewable Energy Lab NREL) and, more recently, RMI, have catalogued these studies and observed which specific categories of benefits each considers.[10]

There are relatively few examples of the use of calculated avoided cost or renewable benefits in tariffs for paying renewable energy sources. The most relevant such studies are those for existing value of solar programs, such as in Austin TX and in Minnesota, based on methods developed by Clean Power Research (CPR).

The Austin Energy value of solar tariff (VOST) was first offered in 2012. It uses a two-part structure, where all customer usage is billed at retail rates, and all solar generation, whether used on-site or exported, is credited at the VOST.[11] This value was initially set at $0.128/kWh for typical south-facing systems, on the basis of analysis by CPR, and then lowered to $0.103/kWh in 2014, due to reduced forward fuel prices.[12] Additional up-front incentives are also offered to solar customers, available up to an annual budget limit.

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[9] Price, S., E. Kollman, 2004. New California PUC Avoided Costs for Energy Efficiency, http://aceee.org/files/proceedings/2004/data/papers/SS04_Panel5_Paper20.pdf

[10] RMI, 2013, op. cit., and Contreras, J., et. al., 2008. Photovoltaics Value Analysis, http://www.nrel.gov/docs/fy08osti/42303.pdf

[11] Rabago, K., Norris, B., Hoff, T., 2012. Designing Austin Energy's Solar Tariff Using A Distributed PV Calculator, http://www.austinenergy.com/About%20Us/Newsroom/Reports/solarGoalsUpdate.pdf

[12] Austin Energy, 2013. https://powersaver.austinenergy.com/wps/portal/psp/about/press-releases/new-value-of-solar-rate-takes-effect-january

The state of Minnesota has approved a similar VOST, which utilities can choose to adopt as an alternative to net energy metering. To date, the VOST has not yet been offered to customers by a utility. The VOST methodology was also developed by CPR, and it is intended to be tailored to a specific utility and its cost structure. Based on typical 2013 values, CPR estimates the VOST at $0.135/kWh.[13]

A similar analytic approach is taken by Crossborder Energy, who conducted studies for industry groups in Arizona, California, and Colorado. These studies show relatively higher avoided costs of generation capacity and transmission capacity, partly due to the closer coincidence of peak load and solar output in Southwest states, and they are among the few studies to that that found significant value in avoided ancillary services and reserve capacity.[14] Because of the high avoided capacity costs, these studies report larger overall benefits of renewable energy than corresponding studies commissioned by the utilities in Arizona and Colorado.[15]

Other studies estimate the benefits of renewable generation as part of an analysis of the cost-effectiveness of net metering programs in various states, using similar methods to those described above.[16] On the other hand, studies of feed-in-tariffs (FITs) are not very relevant to determining avoided cost or value of renewables, because FIT rates are mostly based on the *cost* of renewable generation, rather than its benefits or value.

As the costs of renewables have fallen, FIT values have been reduced. In Germany, for example, the FIT is now generally lower than the retail rate. As a result, the FIT now functions as a two-part tariff, paying the lower FIT for exported energy and the higher retail rate when on-site production offsets the customer's usage.[17] Solar developers have responded to this change by tailoring designs to smooth production over more hours (for example, east/west orientation) rather than maximizing total output (south orientation).

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[13] Clean Power Research (CPR), 2014. Minnesota Value of Solar: Methodology, https://mn.gov/commerce/energy/images/DRAFT-MN-VOS-Methodology-111913.pdf

[14] Crossborder Energy, 2013. The Benefits and Costs of Solar Distributed Generation for Arizona Public Service, http://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf, Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado, http://www.oursolarrights.org/files/5513/8662/3174/Crossborder_Study_of_the_Benefits_of_Distributed_Solar_Generation_for_PSCo.pdf, Evaluating the Benefits and Costs of Net Energy Metering in California, http://votesolar.org/wpcontent/uploads/2013/07/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf

[15] SAIC Energy, 2013. Solar PV Value Report, Arizona Public Service, http://www.solarfuturearizona.com/2013SolarValueStudy.pdf, and Xcel Energy, 2013. Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System, Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223.

[16] RMI, 2013, *op. cit.*

[17] Rocky Mountain Institute, 2014. German Solar Market Evolution, http://blog.rmi.org/blog_2013_10_01_german_solar_market_evolution

On Kauai, payment for customer-sited solar generation purchased by KIUC follows a similar two-part arrangement.

Relevance of Existing Methodologies in the Hawaiian Context

While it would be convenient to adopt existing methodologies in whole or part, it is important to examine their details with an eye toward the specifics of the Hawaiian context. Compared to mainland utilities, for which most of the existing work on renewable energy valuation has been performed, the Hawaiian context regarding the electricity system and renewable energy is significantly different.

Key questions and uncertainties specific to Hawai'i are summarized in Table 1.

Table 1. Key questions and uncertainties specific to renewable energy benefits in Hawai'i

Hawaiian utilities	Mainland utilities
High retail rates drive concern over excess or unfair payments under net metering	Retail rates are (mostly) still insufficient to motivate distributed renewable investment
Avoided fossil fuel is mostly oil, which is expensive, carbon intensive, exposed to volatile and insecure global markets	Avoided fossil fuel is mostly gas, although its domestic market is also volatile
Uncertain reference case resource plan, prospect of shifting a substantial share of generation from existing oil-fired to LNG	Generation resource mix is stable, with most new supply from gas and renewables
The large share of renewable generation already on the island systems makes it more difficult to determine marginal supply sources and expansion resource types	Renewable generation is not yet sufficient to influence the marginal supply sources or expansion resource types
The large renewable share today increases risk of local or system-wide surpluses and resulting curtailment of renewables, while increasing the incentive for energy storage	Modest renewable share in a large inter-connected system, to date, has relatively low risk of curtailment and less value for storage
Energy imports costs an island economy economic development potential; local energy production enhances this potential	Difficult to draw boundaries around area of economic development interest, can assess only total employment or revenue impact
Little use of advanced metering and time-differentiated rate structures	Widespread use of advanced metering and time-differentiated rate structures

The most obvious difference is that the Hawaiian electricity grids are small, isolated systems, rather than very large interconnected networks. This reduces the quantity and diversity of supply and demand-side resources that can be harnesses to balance variation in loads or in production from renewable sources, increasing the risk, for example, that excess renewable generation would have to be curtailed.

The energy supply in Hawai'i is dominated by imported oil. The power generation fleet has been developed with almost entirely diesel and fuel oil-fired generation, in contrast to mainland utilities that rely on varying combinations of baseload and dispatchable

generation from coal, natural gas, nuclear and hydro power sources. Oil-fired generation is negligible on the mainland, except as a backup fuel for units with dual-fuel capability.

Due to the dependence on oil, energy, and especially electricity, is relatively very expensive in Hawai'i. Utility production costs and retail electricity rates in Hawai'i are more than double those of most mainland utilities. Transport fuels are also more expensive in Hawai'i, since the fuel supply is 100% imported into a small market with limited refining capacity. An important consequence is that renewable energy has become cost-competitive with conventional energy supplies earlier in Hawai'i than elsewhere, making the present topic of the value of renewable energy more relevant.

Another consequence of high fuel prices is that the reference case electric utility resource plan is somewhat uncertain, in contrast to those of most mainland utilities, whose resource mix is stable, with most new supply from gas, energy efficiency and renewables. Hawai'i has the prospect of shifting a substantial share of generation from existing oil-fired to liquid natural gas-fired (LNG) generation. This prospect makes it less certain which, or if, generation capacity could be replaced or deferred by renewable sources.

The favorable economics for renewable energy has driven rapid growth in renewable energy, especially solar photovoltaics, in Hawai'i. Installed solar capacity has reached almost 200 MW on Oahu and almost 100 MW in the rest of the state.[18] The high and growing penetration of variable renewables sources (solar and wind) in the state's small, isolated electric systems is already unlike almost anything experienced to date on the mainland and elsewhere. Even grids with large amounts of renewables, such as solar and wind in Germany or California, or wind in Denmark, Texas and Iowa, are part of large, interconnected systems in which the overall share of variables renewables is still modest.

The high penetration of renewables in small, isolated power systems puts Hawai'i in unexplored territory, at the frontier in terms of addressing the challenge of integrating variable renewable resources. A great deal of leading-edge technical work is underway to resolve the engineering questions around grid management with the high penetration of renewables in Hawai'i, including recent work for the Hawaii Natural Energy Institute, led by General Electric.[19]

With regard to the valuation of renewable energy benefits, the Hawaiian context presents unique challenges. Existing methodologies, developed mostly for mainland utilities, generally assume that renewable energy causes a small, marginal displacement of existing supply sources in the short term, and potentially a marginal change or deferral of the reference case resource plan in the longer term. Wholesale change, beyond such marginal effects, is not readily captured in existing methods. For example, renewable

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[18] Energy Information Administration, 2015. Hawaii's electric system is changing with rooftop solar growth and new utility ownership, http://www.eia.gov/todayinenergy/detail.cfm?id=19731

[19] GE Energy Consulting, 2015. Hawaii RPS Study, 2015, http://www.hnei.hawaii.edu/sites/www.hnei.hawaii.edu/files/Hawaii%20RPS%20Study%20Executive%20Summary%20Final.pdf

energy penetration high enough to cause curtailment of renewable sources is only beginning to be considered in assessment of power system economics in California.[20]

In Hawai'i, substantial changes to the power supply system are already beginning to occur, beyond the sort of marginal effects assumed in the existing valuation methods for mainland utilities. The prospect of frequent curtailment of renewable generation is real. Thus, the power planning context has moved beyond the assumption of a stable supply system with only marginal effects from renewable supply. Rather, the integration of a large share of renewables is now a principal planning question and, at the same time, the prospect of shifting a substantial share of generation from existing oil-fired generation to LNG creates more uncertainty.

These unique qualities of the Hawaiian context, regarding the electricity system and renewable energy, tend to confound existing valuation methods and may dilute the relevance of existing valuation methodologies, based on the stable assumptions of mainland utilities. Thus, one should be careful and selective in applying the lessons from existing methodological work to the new, changing conditions in Hawai'i. Such differences will be relevant in the detailed discussion below about avoided costs and renewable energy valuation.

Categories of Renewable Energy Benefits Most Relevant in the Hawaiian Context

For the purpose of defining the types of economic benefits that are potentially derived from renewable generation, the menu of benefits can be generally categorized as the following:

- Benefits related to fuel energy, i.e., realized via each MMBtu produced,
- Benefits related to electric energy, i.e., realized via each kWh produced,
- Benefits related to electric capacity, i.e., realized via the kW of capacity provided during one or more, generally high-load hours of the year, and
- Other benefits, some of which may be realized as energy- or capacity-related

All of the categories of benefits do not necessarily apply to all renewable energy sources. Table 2 summarizes the general correspondence between the benefit categories and the main renewable fuel and electric generation technologies. Fuel energy-related benefits apply to all the technologies, as they represent the sum total of renewable fuel benefits, and they appear to be the most important component of the renewable electricity benefits.

In the Hawaiian context, electric capacity-related benefits appear less important, based on low estimates of ELCC values for solar and wind in particular. The benefit of avoided energy losses only applies to distributed sources, downstream of the T&D grid. Values of other distributed benefits, such as distribution capacity, ancillary services, etc., only apply to distributed sources, and are further limited by low ELCC values.

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[20] Energy and Environmental Economics (E3), 2014. Investigating a Higher Renewables Portfolio Standard in California, https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

Note, however, that the role of generation capacity could change in Hawai'i in the near future. Growing renewable penetration will initially trigger some rate of curtailment. As system planning responds to the need to integrate more renewable sources, capacity resources will necessarily become more flexible, providing a wider range of peaking, ramping and ancillary service needs. Some of these services will be supplied by renewable sources, demand-side resources like demand response, and energy storage.

Table 2. Applicability of renewable energy benefits by technology

Benefit category	**Biofuels for transport**	**Distributed solar PV**	**Central solar PV or CSP**	**Wind**	**Hydro (run-of-river)**	**Geo-thermal**	**Biofuel – fired power generation**	**Distributed generation from biofuel**
Fuel cost	√	√	√	√	√	√	√	√
Hedge value	√	√	√	√	√	√	√	√
Emissions	√	√	√	√	√	√	√ & biogas may have CH4 benefit	√
Energy losses	n/a	√						√
Generation, transmission system capacity	n/a	minimal as the net load peak moves later in the evening	Minimal, √ for CSP + thermal storage	√ for a portfolio of sources	√ for a portfolio of sources	√	√	√
Distribution capacity, ancillary serv.	n/a	minimal, maybe zero or negative						depends on location, operation
Economic development	?	?	?	?	?	?	?	?

Figure 1 compares the range of benefit values for the main categories of renewable electric energy benefits, as catalogued in a meta-study by Rocky Mountain Institute (RMI),[21] with an approximate range of energy-related benefits in Hawai'i. The Hawaiian costs are far higher, due to the high fuel costs associated with oil-fired power generation.

Accordingly, one can project that the avoided fuel-related costs from mainland utilities, as reported by RMI, would be higher in Hawai'i, for categories such as fuel, hedge value and losses. Other categories would not necessarily be higher in Hawai'i and, for distribution-level benefits like distribution capacity and ancillary services, could be lower. From this perspective, the avoided energy-related costs clearly appear to dominate the valuation of renewable electricity benefits, with a possible contribution from generation capacity in the case of baseload or dispatchable renewable sources.

The application of renewable energy benefit values to renewable electricity tariffs, for example as an alternative to net energy metering, would fit the model of the two-part tariff. The basic formula is that the renewable energy owner is paid for power produced

[21] RMI, 2013, *op. cit.*

according to its benefits, and on-site consumption is billed at the default retail rate. This approach is used, for example, in "value of solar" tariff methods developed by Austin Energy in Texas and the state of Minnesota.

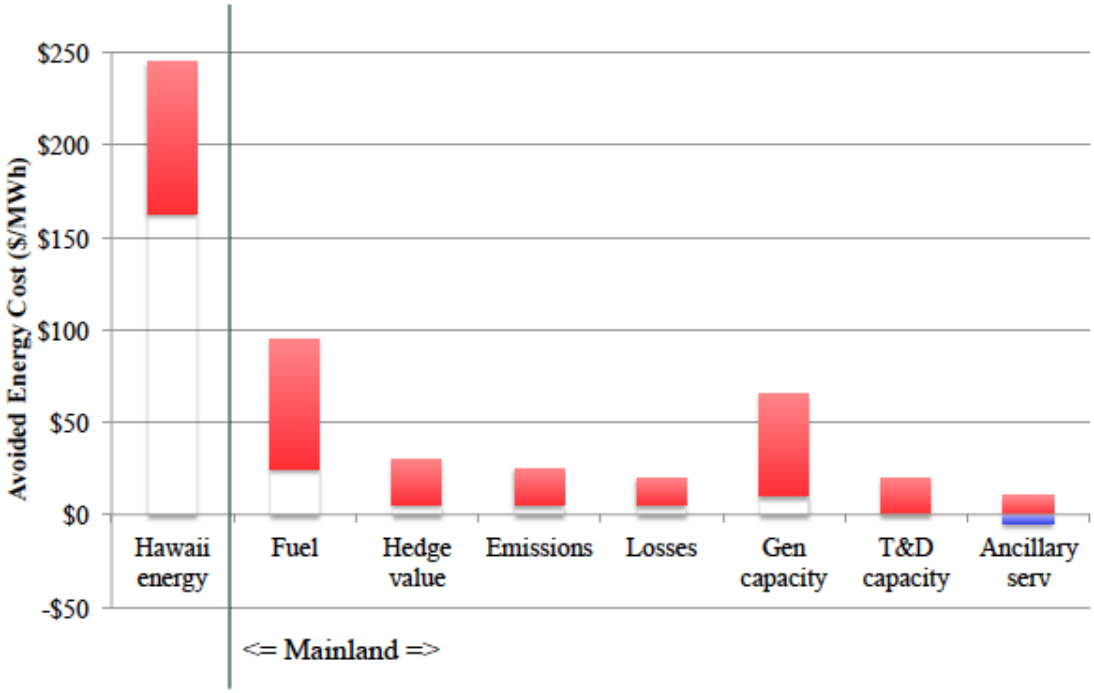

Figure 1. Range of mainland utilities' renewable benefit values, compared to range of Hawai'i avoided energy-related costs. Source: Rocky Mountain Institute 2013.

Because the energy- and capacity-related benefits of renewable energy vary over time, it might be appropriate to apply a time-varying tariff to capture these variations, for example in customer segments where advanced metering is feasible. If a time-varying valuation formula is used, it should be designed to be stable and predictable over the renewable energy investment time horizon. A renewable tariff that is adjusted over time, for example according to an index of future fuel prices, would be less predictable than traditional tariff terms, and could increase financial risk.

Fuel energy-related benefits

Fuel energy-related benefits are proportional to renewable energy produced and to the value of each MMBtu of fuel energy. For renewable fuels, the fuel energy-related benefits represent the sum total of renewable energy benefits. For renewable electricity, the calculation is more complex, as the fuel energy-related benefits must be converted to electric energy-related benefits, accounting for the efficiency of electric generation and possibly for losses in the delivery system.

Fuel-energy benefits for renewable fuels and electricity include avoided fossil fuel costs, emission reduction benefits and the risk-hedging value related to fossil fuel price

variation. Benefits categorized as other benefits below, such as local economic development benefits, might potentially be treated as energy-related benefits.

Figure 2 illustrates the effect of including hedge value and emission costs, in addition to fuel costs, to estimate fuel-energy benefits for renewable fuels and electricity.

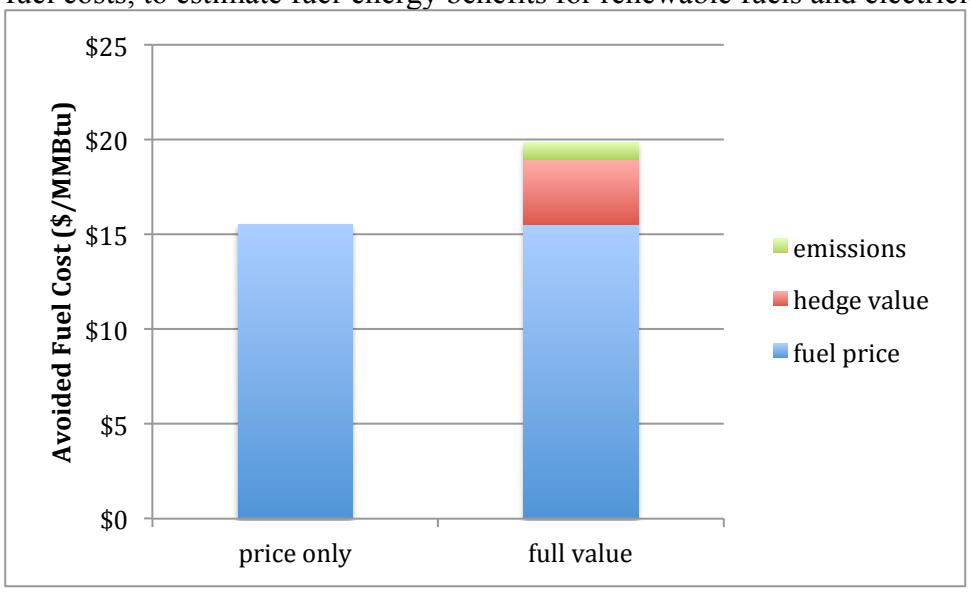

Figure 2. Comparison of projected fuel price and full avoided fuel cost in Hawai'i, based on assumptions used for examples in this report (22% hedge value, $9/ton CO2 cost).

Avoided fossil fuel costs

Avoided fossil fuel cost is typically the most important component in the valuation of benefits of renewable electricity, and it's the sum total of renewable fuel benefits. It is simply the value of the fossil fuel saved by producing the renewable energy source, rather than from the marginal source of energy that it replaces, which is typically fossil fuel.

While the current fossil fuel price can be directly observed, the avoided fuel cost for a renewable energy project depends on fuel process over the future life of the project. The future series of annual fuel price values are levelized over the renewable investment lifetime (typically 20+ years) to obtain a single value in $/MMBtu.

The fuel price forecast is generally taken from commodity future prices as long as they are available, and then a long-term forecast from the EIA, IEA, or similar public source is used. The market price must be adjusted for delivery in the local market, which on the mainland might involve an adder to the natural gas price at the Henry Hub in Louisiana.

The marginal fuel in Hawai'i is generally diesel oil, which is traded in global as well as domestic markets. One can access fuel price forecasts for these markets. To apply fuel price data to Hawai'i, it is necessary to include an adder for delivery in Hawai'i.

Unlike mainland utilities whose marginal fuel is typically domestic natural gas, in Hawai'i it is generally low-sulfur fuel oil, but it can also be diesel oil. For electricity

generation, DBEDT publishes monthly average generation fuel costs for low-sulfur fuel oil and diesel fuel.[22]

Fossil fuel price risk hedging value

Once a renewable fuel production or power generation system is installed, it is nearly a constant-price source of energy, subject only to relatively small annual variations in total production. Therefore, an internally consistent comparison with fossil fuel energy would be against a certain-price source. Fossil fuel prices, of course, are far from certain or constant; they are highly volatile.

Fuel consumers directly bear the risk of fossil fuel price variations. In most electric utility systems, the customer bears the risk of fossil fuel price variations passed trough in the utility bill. Conversely, the removal of price risk by nearly constant-price renewable production provides value to the customer.

Thus, the fuel price risk hedging value is the difference between the forecasted fuel price and its certain-price equivalent. The hedge value depends on the choice of fuel price forecast and the approach to determining certain-price equivalence. Only a few of the recent studies on renewable benefits and costs account for hedging value quantitatively.

The VOST methodologies used by Austin Energy and Minnesota use NYMEX forward market for future fuel (natural gas) prices, then extrapolate beyond the time horizon of the current market, using average escalation rate of futures (4.8%/yr in the Minnesota case), and these prices are discounted at the "risk-free" Treasury bond rate. The resulting certain-price equivalent value is about 13% higher than the levelized fuel price, and this difference represents the hedging value in these studies.[23]

The use of the forward market price, discounted at the risk-free rate, is a reasonable approach to determining certain-price equivalence, as long as the future prices are visible. However, applying this method to an extrapolation of price values beyond the time horizon of the current market, as in the Minnesota VOST method, is rather suspect.

The future price uncertainty is great, due to the lack of market data more than a few years ahead. Relying on official projections for fuel price forecasts is unfortunately rather arbitrary. For example, EIA forecasts tend to track current prices at the time of forecast, and each year's forecast values tend to vary in line with current price levels.

Emission reductions

Renewable energy that replaces fossil fuel can reduce local criteria pollution (NOx, PM-2.5, etc.) and emissions of CO2, the main greenhouse gas (GHG). Avoided costs of regulated emissions should already be captured in the avoided fuel costs and, for

[22] DBEDT monthly data are at http://dbedt.hawaii.gov/economic/energy-trends-2/
[23] CPR, 2014, *op. cit.*

electricity, operating and capacity costs of generation, to the extent that more expensive sources are being deployed in order to reduce emissions at least to regulated limits. However, there is additional benefit in avoiding currently unregulated emissions and their human health and global climate impact.

In theory, the avoided cost of emissions should reflect the avoided damage to the environment, in terms of human health or the global climate, and this damage is attributed to the avoided fossil fuel-fired generation. There is a substantial literature on the quantification of this approach to environmental valuation. The results vary widely, with a great deal of uncertainty regarding attribution of damages to specific sources.[24] Also, the treatment of environmental costs as "externalities" in energy planning and procurement is legally weak.

On the other hand, one can treat unregulated emissions as a potential avoided cost, albeit a rather uncertain one, assuming future regulations are more stringent than at present. This approach is analogous to the typical treatment of future fuel costs, which are also highly uncertain, even if today's value is known exactly. As an avoided future cost, the value of avoided emissions depends on the valuation of currently unregulated emissions.

Combustion CO2 emissions simply reflect the mass balance of the combustion process – essentially all carbon that enters a power plant in the fuel leaves the plant as CO2.[25] Thus, estimating avoided CO2 emissions per kWh is a simple extension of the avoided energy cost calculation, which gives avoided fuel energy per MMBtu. Accordingly, the fuel carbon content determines a simple ratio of CO2 emissions per unit of fuel energy input, e.g., 75 kgCO2/MMBtu for diesel fuel.

Avoided SO2 emissions would be similar, since fuel is the source of sulfur emissions, although SO2 can be mitigated by post-combustion treatment. In any case, with the exception of coal-fired generation, SO2 emissions from electricity generation are a generally small value. Avoided NOx emissions are more complex, since nitrogen is present in the combustion air, and emissions depend critically on the process details.

Estimating a monetary value of each ton of unregulated emissions is inherently far more uncertain. Omitting this category of benefits, however, would implicitly treat its value as exactly zero for 20+ years. A value of zero forever is clearly an unlikely result, and it is certainly a lower value than any reasonable estimate. The challenge, then, is to find such a reasonable, non-zero estimate.

An estimate of the avoided cost of unregulated emissions was included in the E3 avoided cost analysis for the California PUC from 2003-2012, until the state's carbon market began operating under the AB-32 GHG reduction law, thus internalizing the CO2 emission component of the methodology. A similar approach to accounting for

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[24] See, for example, National Academies Press, 2012. Hidden Costs of Energy, at http://www.nap.edu/openbook.php?record_id=12794

[25] A very small fraction of the fuel carbon leaves the combustion process as CO or hydrocarbons, but even these molecules react to produce mostly CO2 in a short time.

unregulated CO2 emissions was used for planning and procurement by the California PUC, and it was adapted for application in other states such as Colorado and Idaho.[26]

Although a projection of future emission costs is inherently very speculative, one can at least define reasonable boundaries. The default estimate of zero is the minimum, but probably not a reasonable estimate. The upper boundary can be estimated from the avoided cost of aggressive GHG mitigation measures such as carbon capture and sequestration. A range of intermediate estimates can be observed from recent economic modeling studies, for example from the Energy Modeling Forum, on the carbon price needed to achieve likely future emission targets, such 20% cuts by 2030.[27]

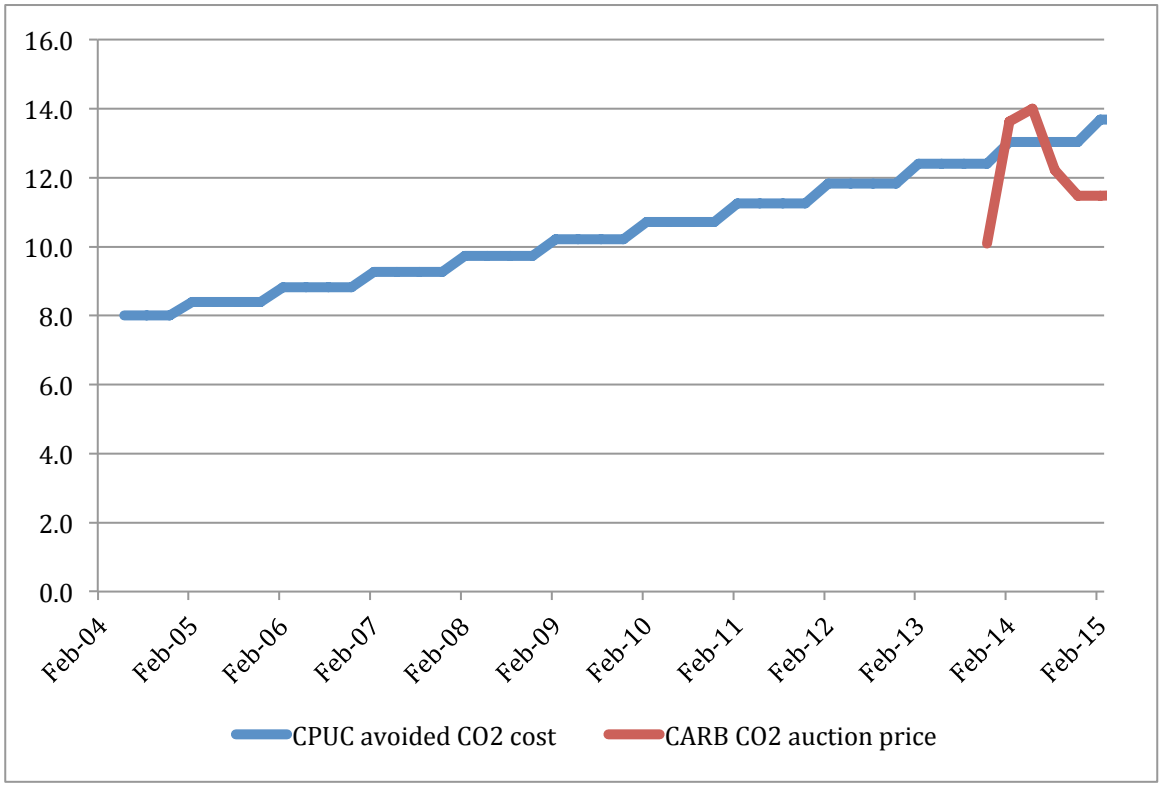

Figure 3. Comparison of CPUC avoided CO2 cost estimates, from 2003 avoided cost methodology, against recent California Air Resources Board CO2 auction prices

The California PUC avoided cost methodology took this approach in 2003, and it produced the avoided emission cost estimates shown in Figure 3, in comparison to the recent market prices under the California Air Resources Board CO2 auction program. One should not expect agreement, but one can argue that the estimates are reasonable and better than assuming a perpetual value of zero.[28]

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[26] Karl Bokenkamp, Hal LaFlash, Virinder Singh, Devra Wang, Hedging Carbon Risk: Protecting Customers and Shareholders from the Financial Risk Associated with Carbon Dioxide Emissions, The Electricity Journal, Volume 18, Issue 6, July 2005, Pages 11–24

[27] See https://emf.stanford.edu/

[28] E3 and RMI, 2004. Methodology and Forecast of Long Term Avoided Costs for the

The avoided cost approach directly values NOx and PM-2.5 emissions, based on current California offset prices generators must pay. For electricity generation, the estimated emission rates are based on the implied heat rate in each hour given the hourly electricity market prices. CO_2 emission rates also depend on marginal heat rates, and monetary value is based on levelized, long-run averages of emission credit prices in other markets, over all years of the investment horizon. The resulting cost, per MMBtu, tends be dominated by CO2 emissions, even at rather conservative forecasts of carbon market prices.

The VOST methodology used by Minnesota includes emission externality values for NOx, SO2 and CO2. At the assumed value of $40/ton, the CO2 emission cost value dominates the results, as the other emissions sum to an equivalent value of only about $1/ton CO2.[29] Again, the value of CO2 emission cost would dominate the results, even at a more conservative estimate of carbon prices.

The VOST methodology used by Austin Energy includes the avoided cost of buying renewable energy certificates (RECs), widely used for compliance with state renewable portfolio standards (RPS), at the current market price, as a proxy for avoided cost of emissions.[30] The Crossborder Energy study for Colorado suggests a similar method.[31]

The logic of this approach, that the value of renewable generation includes the value of *not* buying renewable generation, seems rather circular, and not indicative of the benefit derived from renewable energy in lieu of fossil energy. However, one could argue that, under a binding, mandatory renewable portfolio standard, environmental costs are already internalized, and the avoided cost of renewable energy is simply the lowest competing renewable energy cost. This logic returns the analysis to considering renewable energy costs, which are the basis of feed-in tariff studies, but don't reflect renewable benefits.

Electric energy-related benefits

Estimating avoided fossil fuel cost is nearly a complete methodology for the valuation of renewable fuel benefits. Other, relatively uncertain benefits, described below, are all that remain to be considered. On the other hand, avoided fuel cost is just the first step in estimating the avoided energy cost of electricity production, although it is typically the most important component in the valuation of benefits of renewable electricity.

Electric energy-related benefits are proportional to renewable energy produced and to the value of each kWh of electric energy. Thus, energy benefits for renewable electricity

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Evaluation Of California Energy Efficiency Programs, https://ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

[29] CPR, 2014, *op. cit.*

[30] Rabago, et. al., 2012, *op. cit.*

[31] Crossborder Energy, 2013. Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado, http://www.oursolarrights.org/files/5513/8662/3174/Crossborder_Study_of_the_Benefits_of_Distributed_Solar_Generation_for_PSCo.pdf

include avoided fossil fuel costs, emission reduction benefits and the risk-hedging value related to fossil fuel price variation. In addition, electric energy benefits can include avoided energy losses. Benefits categorized as other benefits below, such as local economic development benefits, might potentially be treated as energy-related benefits.

In addition to the avoided fuel cost, avoided electric energy cost must account for the generation heat rate, which is the efficiency of conversion from fuel to electricity. Thus, the value of avoided emissions depends on the choice of marginal generation source(s), their fuel type(s), heat rate(s), and carbon content of the fuel (for emissions). For distributed renewable sources downstream of the transmission and distribution (T&D) grid, losses in the T&D grid are an additional component of the avoided energy cost.

The basic method is simple. In any hour of the year, the avoided electric energy cost is the product of the avoided fuel cost and the heat rate for the marginal generation source. For most mainland utilities, the marginal source is considered to be a mix of gas-fired combustion turbines (CTs) and combined cycle (CC) plants, and sometime coal-fired steam plants. In Hawai'i today, the marginal source is generally one of several types of oil-fired plants. For central renewable generation sources, which feed power into the T&D grid, the full value of the avoided electric energy cost is the following:

Avoided electric energy cost ($/MWh), hour i =

Avoided fuel cost ($/MMBtu) * heat rate for marginal generator (MMBtu/MWh), hour i

Annual values of avoided energy cost are the sum of each hourly value of the energy cost multiplied by the renewable production in that hour, divided by the total annual production. The resulting value is simply the annual weighted average of the hourly avoided energy costs. This annual avoided energy cost can then be levelized over the renewable investment lifetime (typically 20+ years) to obtain a single value in $/MWh.

Figure 4 illustrates the effect of including hedge value, emissions and losses, in addition to avoided fuel costs, to estimate electric energy-related benefits of renewable generation.

Marginal generation heat rate

Defining the marginal generation source reveals the marginal generation source, fuel type, and heat rate. However, this step is the most complex one in estimating avoided fuel cost, especially in Hawai'i. The complexity lies in the challenge of understanding the hourly generation stack as it changes over time, and in response to increasing renewable output.

The simplest approach is to assume types of marginal plants one for on-peak hours and one for off-peak hours. In most systems, however, there is too much variation in the real generation fleet for this approach to be accurate. An alternative, where there is a real-time

electricity market, is to use hourly market prices to reveal marginal heat rate (heat rate = power market price / fuel price).[32] This approach does not apply in Hawai'i.

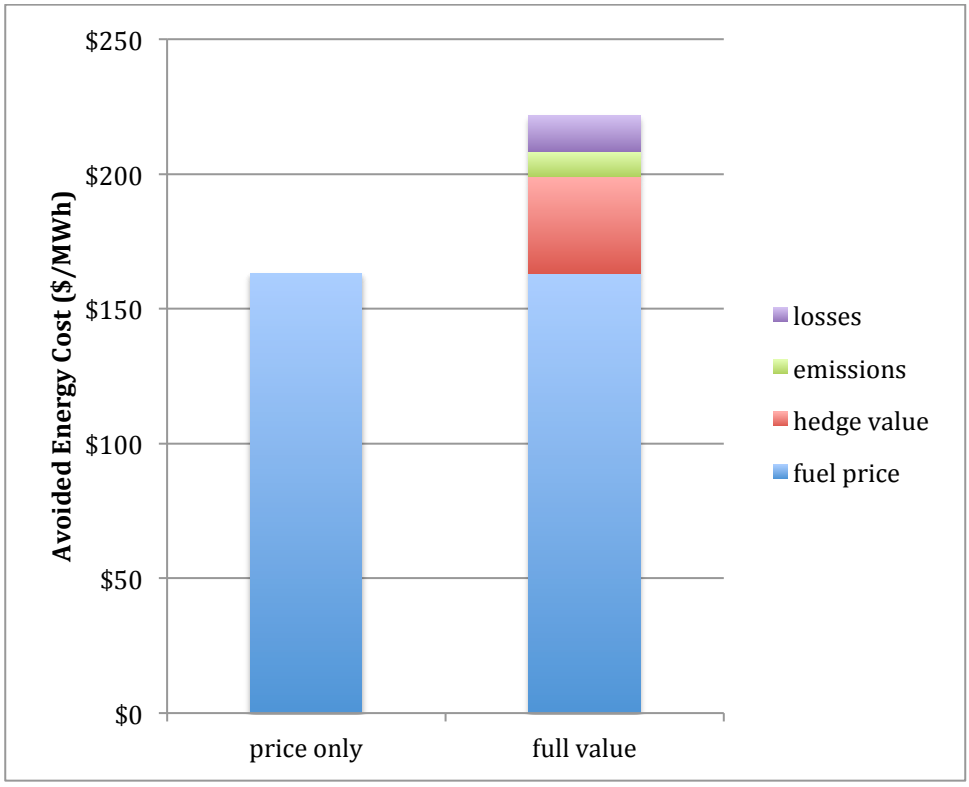

Figure 4. Comparison of avoided electric energy cost, based on projected fuel price only and on full avoided energy cost, using assumptions from examples in this report (22% hedge value, $9/ton CO2 cost, 6% losses).

A more detailed approach is to simulate the hourly operation, or dispatch, of the generation fleet on an hourly basis. The VOST methodologies used by Austin Energy and Minnesota apply an hourly heat rate, assuming natural gas-fired generation at the margin, to a simulated net load profile with solar production included. The net load is defined as the total customer demand minus the output of non-dispatchable generation, including all variable renewables sources such as solar and wind (see Figure 8).

When renewable production is included to determine the net load profile, it is essential to take the utility load data and renewable output data, or the weather data used to drive simulated renewable output, from the identical time period. Because weather drives both

[32] E3, 2008. Time Dependent Valuation for use in Regional DOE Air Conditioning Standards, https://ethree.com/public_projects/tdv.php

loads and renewable performance, a mismatch in weather data could lead to very unrealistic results.[33]

To analyze the hourly dispatch of the generation stack over time, utilities typically use a production cost model, which simulates the operation of the entire generation fleet in response to hourly loads and other inputs. Some such models are commercial products that are fairly transparent, albeit complex and data-intensive, to operate. In Hawai'i, the KIUC uses a commercial production cost model (UPLAN) to simulate hourly dispatch, revealing marginal generation source, fuel type, and heat rate, which could be used for an avoided electric energy cost analysis.

An alternative approach is to build a spreadsheet-based generation stacking model to simulate hourly dispatch, based on utility data on loads, existing and planned generation sources, etc., and assumptions about present and future fuel prices. A stacking model is essentially a list, or stack, of available generation sources, ranked in order of variable (i.e., fuel) cost, aligned with hourly loads, net of renewable and other non-dispatchable, must-run generation.

For each hour, the dispatched resources are all those with the lowest variable costs, up to the point where the total generation matches hourly net load. The most expensive generation needed to meet net load in a given hour is the marginal source in that hour. In reality, utility-specific adjustments are made to account for minimum plant output levels, reliability constraints, etc., such that a realistic stacking model can be rather complex.

In Hawai'i, the E3 avoided cost model relies on a stacking model to analyze generation dispatch for HECO, MECO, HELCO. While E3 was able to use output from the KIUC production cost model, the HEI models are not sufficiently transparent to adopt for avoided cost calculations, so a generation stacking model was necessary.[34]

With either type of model, analyzing dispatch in the present year is straightforward, and results can be compared with actual operation to verify that the model is realistic. The challenge comes in projecting dispatch in future years, when the loads and generation stack will be different and less certain. Moreover, increasing renewable penetration in the future might alter which sources are at the margin, and high renewable penetration could result in a renewable source being at the margin during certain hours. In this case, the result would likely be partial curtailment of the renewable resource, resulting in a zero avoided energy cost for that hour.

Note that the definition of the marginal source becomes more uncertain when the future generation expansion plan is affected by adding renewables, energy efficiency, and other

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[33] Datta, K., L. Hansen, J. Swisher, 2006. Valuation of Renewable and Distributed Resources, http://www.rmi.org/Knowledge-Center/Library/2006-09_ValuationRenewableDistributedResources

[34] E3, 2014. Evaluation of Hawaii's Renewable Energy Policy and Procurement, http://puc.hawaii.gov/wp-content/uploads/2013/04/HIPUC-Final-Report-January-2014-Revision.pdf

technologies that modify the net load profile. Thus, while the precision of a detailed dispatch model is satisfying, one should be realistic about the uncertainty of the assumptions over time, and the limited certainty of future analysis results.

Avoided energy losses (electricity only)

The avoided energy losses are the additional electric energy saved by producing power from a distributed, on-site renewable source such as solar, rather than from a central, fossil fuel-fired (or renewable) source of energy that must transmit power to the load through the transmission and distribution (T&D) grid. On-site power can avoid most of the incremental losses associated with the avoided energy; therefore, avoided energy losses are a multiplier to the avoided fuel and other electric energy-related cost terms.

Avoided energy losses depend on the T&D loss rate and the avoided fuel and other fuel-related energy costs. The VOST methodologies used by Austin Energy and Minnesota apply an hourly loss rates as an adder to each hourly avoided energy cost, which are then averaged over the year and levelized over the investment lifetime.

The full value of the avoided electric energy cost, for a *distributed renewable source*, is the following:

$$\text{Avoided electric energy cost (\$/MWh), hour i} = \frac{\text{Avoided fuel cost (\$/MMBtu) * heat rate for marginal generator (MMBtu/MWh), hour i}}{\{1 - \%\ \text{T\&D loss rate}\}}$$

One can also use a simple average annual loss rate, applied to the total avoided energy cost, with only an insignificant loss of accuracy. With this approach, one can divide the annual value of avoided electric energy cost, which is the annual weighted average of the hourly avoided energy costs, by the *average* T&D loss rate, to obtain the annual avoided electric energy cost in $/MWh.

<u>Electric capacity-related benefits</u>

Capacity-related benefits are proportional to the capacity value provided by renewable generation, if any, during the few, generally high-load hours of the year that drive the need for supply capacity. Capacity benefits can include avoided system generation and transmission capacity costs, marginal distribution capacity costs, capacity value of avoided losses, and ancillary services.

Figure 5 illustrates the effect of including avoided capacity cost, in addition to avoided fuel and other energy-related costs, to estimate benefits of renewable generation. While replacement of oil with LNG would lower avoided energy costs, it could potentially increase avoided capacity costs for renewable sources that provide substantial capacity credit (high ELCC). Note that, if new oil-fired capacity is needed to meet load growth, avoided capacity costs could also be substantial, even without LNG.

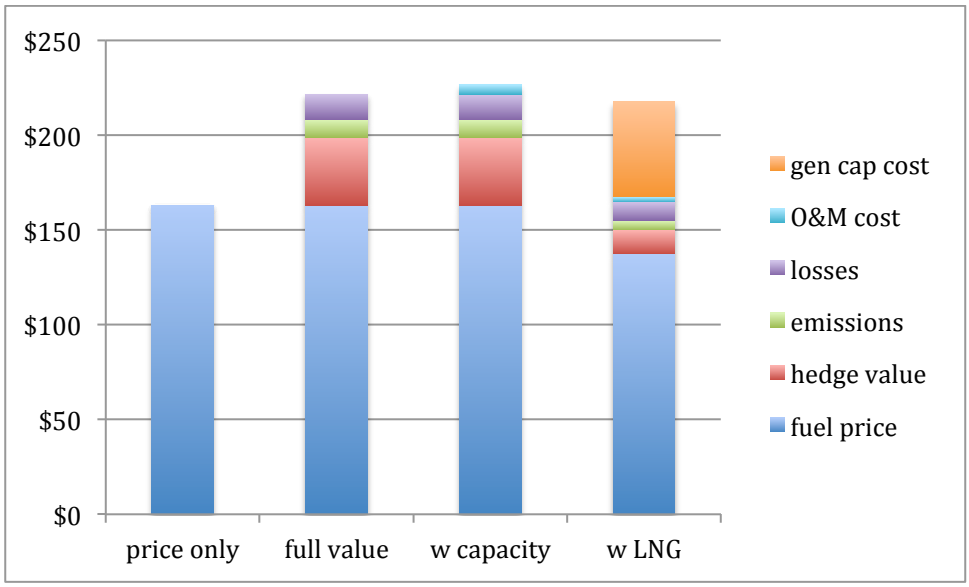

Figure 5. Comparison of avoided electricity cost, based on a) fuel cost only, b) full energy cost, c) full energy and capacity, for status quo with no need for new capacity, d) full energy and capacity, for alterative case with LNG replacement of oil-fired capacity, using assumptions from examples in this report (22% hedge value, $9/ton CO2 cost, 6% losses, $10/kW-year O&M cost, $200/kW-year LNG-fired generation capacity cost).

Avoided system generation and transmission capacity costs

Avoided system capacity cost is realized when the renewable generation source can deliver power that makes it possible to replace or defer some amount of conventional, typically fossil fuel-fired, generation, while serving the same load with comparable reliability. It is the value of the power supply capacity that can be replaced or deferred by producing power from each kW of the renewable source.

The basic method is to identify the type of generation technology planned to meet load growth, estimate its capital cost and other fixed costs per kW of supply capacity, and then adjust the capacity value to account for the renewable source's contribution to meeting peak-coincident load. Finally, the avoided capital cost is allocated to each kWh of annual renewable production.

Thus, the value of avoided system capacity cost depends on the determination of the incremental generation capacity resource(s), the cost of each kW of generation and related transmission capacity, the capacity value of variable renewables, and financial parameters such as discount rate and investment lifetime.

Marginal capacity cost, in $/kW-year, includes the incremental generator's annual fixed operation and maintenance (O&M) cost, plus the levelized value of the installed capital

cost of incremental generation and transmission capacity, over the lifetime of the capacity resource. The discount rate used to levelize the capital cost is generally the utility's after-tax, weighted average cost of capital (WACC). For a public utility, it is appropriate to use the estimated rate of return on reserves, without any effect of taxes. Some valuation studies recommend using a lower rate when comparing to renewable sources.

Determining the incremental generation capacity resource is the step that can add the most uncertainty. Mainland utilities tend to use the capital cost of a simple-cycle combustion turbine (CT), or peaking plant, as the proxy capacity resource, with costs of $70-100/kW-year. The transmission capacity cost is typically assumed to be $10-30/kW-year, based on a correlation of transmission investment and historic load growth, or from recent wholesale market purchases.[35]

Avoided capacity cost depends on the need for capacity expansion to meet expected future load growth, or possibly to replace large planned retirements of supply capacity, if any. In a case where there is little load growth and no need for capacity addition, there would be no contribution from incremental capacity investments, and the capacity cost would be just the O&M cost in $/kW-year.

Some examples include the E3 avoided cost model for California, which includes a system capacity cost of $140/kW-year. The VOST methodologies used by Austin Energy and Minnesota indicate capacity costs in the range of about $60/kW-year for Austin and about $90/kW-year for Minnesota.[36] For Hawai'i, the E3 avoided cost study indicates no capacity cost, only O&M, for Hawai'i, Maui, and Kauai, due to excess capacity on their systems. For Oahu, E3 projects significant capacity costs based on generation capacity expansion from 2018.[37]

Once the avoided system capacity cost values are estimated, in $/kW-year, they can be allocated to the renewable energy produced, to arrive at a $/kWh value of avoided cost. One calculates an average value for each kWh of renewable energy by dividing the $/kW-year value by the total annual production in kWh/year.

Alternatively, one can allocate the value to specific hours of production, which correspond to peak load (or net load) hours that drive the capacity cost. For example, if the capacity value is allocated entirely to one maximum load hour, that hour would have a very high avoided capacity cost in $/kWh, and all other hours would be zero. If capacity value is allocated to more hours, e.g., the top 100 load hours, these hours would have substantial avoided cost values and others would be zero.

The most uncertain input to the calculation of avoided capacity cost is the estimation of the capacity value of variable renewable sources, especially solar and wind power. While renewable generation certainly avoids conventional energy generation, avoiding capacity

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[35] CPR, 2014, *op. cit.*
[36] Rabago, et. al., 2012, *op. cit.,* and CPR, 2014, *op. cit.*
[37] E3, 2014, *op. cit.*

requires the renewable source to reliably deliver power during the hours of the year when net loads are highest and drive the need for capacity expansion.

The mainstream approach to estimating capacity value of wind and solar is the effective load-carrying capacity (ELCC). The ELCC value is a percentage, defined as the MW of thermal generation that can be replaced by 1 MW of a renewable source while keeping system loss-of-load-expectation (LOLE) constant. Therefore, it is specific to a renewable technology, design (e.g., solar orientation) and location.

There are also simpler approaches to estimating capacity value. One is to apply the renewable capacity factor (ratio of actual average output to rated output), specifically during the hours of maximum load. This approach is a convenient approximation, but was found to underestimate the actual capacity value of wind and solar when compared to more precise methods.[38]

For geothermal and biomass-fired generation, which can deliver baseload or dispatchable power, this simple method is adequate and typically indicates 80-100% of rated capacity as the capacity value for these sources.

Marginal distribution capacity costs

Like avoided system capacity cost, marginal distribution capacity cost (MDCC) is the value of the distribution capacity that can be replaced or deferred by producing power from each kW of a distributed renewable source. The MDCC varies across different utility planning areas and circuits. For utilities that have distribution planning areas with high MDCC values, distributed generation (DG) that can defer the need for distribution capacity would show a substantial benefit, if installed selectively in such areas.

The MDCC value depends on the local distribution capacity expansion plan, rate of load growth in a given area, capacity value of variable renewables (specific to the area load profile), and financial parameters such as the discount rate. The E3 avoided cost model includes MDCC estimates on an area-specific basis, based on the deferral of the cost of an area's distribution expansion plan, if DG output coincides with the area peak load. For a range of utilities, E3 found MDCC values to range from zero to over $50/kW-year.[39]

The VOST methodologies used by Austin Energy and Minnesota provide for the inclusion of MDCC values on a utility-specific basis, but their representative value estimates are zero and minimal, respectively.[40] For Hawai'i, the E3 avoided cost estimates assume no distribution capacity deferral value and zero MDCC.[41]

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[38] Milligan, M., K. Porter, 2008. Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation, http://www.nrel.gov/docs/fy08osti/43433.pdf
[39] Heffner, G., et al 1994, Variations in Time- and Area-Specific Marginal Capacity Costs of Electricity Distribution," Distribution Automation and Demand-Side Management Conference.
[40] Rabago, et. al., 2012, *op. cit.,* and CPR, 2014, *op. cit.*
[41] E3, 2014, *op. cit.*

Capacity value of avoided losses

Like avoided energy losses, which amplify the avoided energy cost due to T&D losses upstream of a distributed resource, avoided capacity costs can be amplified by upstream losses that add to the system capacity need to meet a kW of load. The capacity value of avoided losses depends on the system capacity costs and the loss rate during the peak load hours that contribute to capacity needs. Typically peak loss rates are higher than average losses.

The VOST methodologies used by Austin Energy and Minnesota apply hourly loss rates for the hours of peak demand to estimate an adder to the avoided capacity cost. This is the most precise method, but one can also estimate the peak loss rate simply from the average annual loss rate and load factor (ratio of annual average load to peak load).

Because line losses are proportional to the square of current, rather than simply current and thus load, the line loss rate is higher during times of peak load. Specifically, the rate of line losses increases roughly linearly with load. To represent these losses, one can assume a constant 2% transformer loss, and the remainder of annual and peak losses are line losses. Applying the linear relationship between load and rate of line losses, we use the ratio of average load to peak load (the annual load factor) to calculate the peak line losses above the average losses. Thus:

Loss rate due to peak load = 2% + { (average loss rate – 2%) / annual load factor }

Ancillary services

The benefit from ancillary services provided or avoided by renewable generation depends on the ability of renewable generation to deliver reactive power, reduce the need for reserve capacity, etc. The net benefit is the value of such services, net of the cost of incremental ancillary services needed to balance the renewable generation.

In general, the value of ancillary services provided by renewables varies widely and is difficult, given current state of art and capabilities, to quantify. Even the sign of its value is uncertain, as renewable generation can result in incremental costs for ancillary services that are on the same order of magnitude as the benefits delivered. The difference of two uncertain values tends to be a small value with a large uncertainty. The RMI meta-study of renewable energy benefits reports only a few literature estimates of ancillary service value, and all are minimal or negative.[42]

An early CPR study for Austin Energy considered the value of supplying reactive power from advanced solar inverters, but its economic value was found to be minimal.[43] The Crossborder Energy study for Arizona estimates an avoided cost of ancillary services and

[42] RMI, 2013, *op. cit.*

[43] Hoff, T., et al, 2006. The Value of Distributed Photovoltaics to Austin Energy and the City of Austin, http://ilsr.org/wp-content/uploads/2013/03/Value-of-PV-to-Austin-Energy.pdf

reserve capacity at $15/MWh.[44] The E3 avoided cost model for Hawai'i includes ancillary services at 1% of energy cost, based on California estimates, but it does not account for offsetting ancillary service costs at high renewable penetration.[45]

Other benefits

Renewable generation can provide additional benefits, for example to the local economy, which are not easily quantified in terms of cost-benefit analysis. Nevertheless, these benefits are meaningful to stakeholders and, if their value is clearly not zero, it is worth exploring potential valuation methods. In order of increasing uncertainty, these benefits include local economic development and security-related benefits.

Local economic development

The potential for local economic development benefits from renewable generation comes from the dollars invested, in lieu of dollars spent on imported fuel, rather than from valuing the energy itself. While some of the investment in renewable generation buys imported hardware, much of it is for labor, goods and services that can be sourced locally. These local expenditures are recycled in the local economy, potentially resulting in more local economic activity and employment than an equal amount of expenditure on imported fuel. In the case of the island economy in Hawai'i, the difference between local and imported goods is relatively clear, and fossil fuel for generation is 100% imported, representing a loss to the local economy.

The value of the economic development benefit depends on the total expenditures and the shares of local vs. imported content of expenditures on renewable energy and fossil fuel-fired generation, the local economic multipliers for these expenditures (generally derived from an input-output model of the local economy) and for general consumer spending.

While the local content of the different energy expenditures is a key driver, the total consumer expenditures on energy also affect the economic development benefit. If the renewable source is less expensive overall than conventional generation, consumers save money and spend it mostly in the local economy, and this net increase in expenditures has a local multiplier effect. On the other hand, if the renewable source increases consumer costs, the reduced consumer purchasing power is magnified by the same multiplier effect.

The value of this economic development benefit is inherently uncertain, within a wide range of plausible estimates. Moreover, the economic development benefit has generally not been valued in avoided cost studies, and it has only recently been addressed in the context of VOST analytics.

For example, the recent CPR study for New Jersey and Pennsylvania estimates a substantial benefit of $40/MWh, based on the increase in state and local tax revenue from

[44] Crossborder Energy, 2013. The Benefits and Costs of Solar Distributed Generation for Arizona Public Service, http://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf
[45] E3, 2014, *op. cit.*

local energy jobs created, relative to conventional generation. However, this approach only counts the direct effect of energy expenditures on employment. It fails to adjust for the possible negative (or positive) net impact on consumer purchasing power if the renewable source increases (or decreases) customer energy costs.

A more realistic approach would be that used in estimates of local employment and economic development impacts of energy efficiency programs. This method accounts for different local content of energy supply and demand-side (efficiency program) expenditures, adjusts for the generally-positive impact of efficiency programs on consumer purchasing power, and applies indirect economic multipliers to the net direct local spending.[46] The main challenge is determining the values for these multipliers.

For solar investments in Hawai'i, a study by Loudat analyzed indirect economic impacts of solar, based on economic relationships extracted from an input-output model for the state. Based on that model, this study applied multipliers of about $2.1 of total output and $0.64 of added labor income, per $1 of solar system costs or consumer savings.[47] These multipliers appear to combine the local content and economic multiplier parameters into a single ratio, which could be a useful input to an economic development benefit estimate.

Also, a recent analysis in support of the NextEra/HECO merger applied the widely-used input-output model IMPLAN to the local economic development benefits of reducing customer energy bills. This study projected that 71% of savings would be spent in the local economy of the state, and the local economic multiplier was 1.53. Thus, each dollar of customer savings would generate an additional $1.00 * 71% * 1.53 = $1.1 in local economic activity, and this would increase gross state product by about $0.67.[48]

Security-related benefits

The potential for security-related benefits comes from the potential improvement in the continuity of supply, particularly in an isolated, island geography with a single point of entry like a seaport. The value would be inherently highly uncertain but, again, if one is confident that zero is not a realistic value, it is worth considering valuation methods.

The value of security-related benefits would depend on the economic value of the risk of business interruption, such as military outage costs and/or civilian insurance premiums, and the degree to which that risk is reduced. A renewable generation unit does not necessarily have the ability to prevent or recover from interruption, simply because its

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[46] Laitner, S., et. al., 1998. Employment and Other Macroeconomic Benefits of an Innovation-Led Climate Strategy in the U.S., *Energy Policy*, vol. 26, pp. 425-433, http://www.sciencedirect.com/science/article/pii/S0301421597001602

[47] Loudat, T., 2013. The Economic and Fiscal Effects of Hawai'i's Solar Tax Credit, https://blueplanetfoundation.org/files/Blue_Planet_Solar_Credit_Report_Jan13.pdf

[48] Reed, John, 2014. Testimony for Nextera Energy, Inc., to Hawaii PUC, Docket No. 2015-0022, Applicants Exhibit-33, http://dms.puc.hawaii.gov/dms/

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fuel comes directly from the earth or the sky. Rather, it would need the ability to start and maintain operation, independent of the central energy grids, in the case of an interruption.

Security-related benefits have generally not been valued in avoided cost studies or in VOST analytics. An early CPR study of VOST valuation for Austin Energy discussed the potential value in disaster recovery, but did not quantify this value. The CPR study noted, however, that realizing a security-related benefit from disaster recovery would require the solar design to include on-site storage and inverter technology that enables operation in an electrically islanded configuration.[49] These are capabilities that most distributed solar installations do not have at the present time.

Recommended Methodologies for Valuation of Renewable Energy Benefits

This section revisits each category of avoided costs and renewable energy benefits, described above, in order to assess available methods and recommend best-practices methodologies that are most relevant for application in the Hawaiian context. Again, the menu of benefits can be generally categorized as fuel energy-related benefits, electric energy-related benefits, capacity-related benefits, and other benefits.

Fuel energy-related benefits: recommended methods

Avoided energy costs are the most important component of the renewable electricity benefits, and the sum total of renewable fuel benefits.

The basic form of this calculation is the following:

Avoided fossil fuel cost ($/MMBtu)

= Fuel price ($/MMBtu) + Hedge value ($/MMBtu) + Emission value ($/MMBtu)

Many studies of avoided costs and renewable energy benefits omit the hedge value and emission value, because they are uncertain. However, including these values is a simple step in the methodology; they are simply adders to the fuel price.

Fossil fuel prices

The future series of annual fuel price values are levelized over the renewable investment lifetime (typically 20+ years) to obtain a single value in $/MMBtu. Diesel fuel prices, based on local delivery in the state of Hawai'i can be taken from DBEDT data. For electricity generation, DBEDT publishes monthly average generation fuel costs for low-sulfur fuel oil and diesel fuel.[50]

[49] Hoff, et. al., 2006, *op. cit.*
[50] DBEDT monthly data are at http://dbedt.hawaii.gov/economic/energy-trends-2/

Fuel price forecasts are typically available for part, but not all, of the investment lifetime. Static values of future fuel prices can be taken from a forward market, e.g., NYMEX West Texas intermediate (WTI), and adjusted for local delivery, using a fixed adder based on historic price differences between a the price at shipping hub and the price of fuel delivered in Hawai'i. For example, regression analysis of fuel price data since 2006 indicates that the diesel fuel price in Hawai'i tracks the NYMEX WTI index, lagged by two months, with an adder of $2.3/gallon ($r^2$=0.65).

Longer term prices are taken from EIA forecasts, adjusted for local delivery. These price forecast values tend to vary in line with current price levels, making the longer-term values less stable than they should be. Therefore, EIA price forecast values should be averaged over the last five years of forecasts, in order to smooth the results.

Fossil fuel price risk hedging value

The fuel price risk hedging value is the difference between the forecasted fuel price and its certain-price equivalence. The hedge value depends on the choice of fuel price forecast and the approach to determining certain-price equivalence. The VOST methods used by Austin Energy and Minnesota use NYMEX forward market for future fuel (natural gas) prices.

Use of the forward market price is a reasonable approach to determining certain-price equivalence, as long as the future prices are visible. However, beyond the time horizon of the current market, future price uncertainty is even greater, due to the lack of market data. Nevertheless, future market prices provide a true indication of a certain-price equivalent, and the longer time over which market prices can be derived, the better.

The recommended method is to rely on market price information, which can provide a direct indication of the value of price certainty. To reveal this value, it is necessary to obtain fuel prices over a longer time horizon, at least 10 years and ideally 20 years, than that of commodity markets such as the NYMEX. Such price information would have to come directly from bids by fuel vendors or financial intermediaries in response to real orders to purchase fuel. The orders would need to have a fixed price, or a fixed schedule of price values, over the 10-20 year time horizon, in order to indicate the hedge value.

One useful example of such a contract is the recent 10-year natural gas supply contract between Xcel Energy and Anadarko. The contract was part of a new Xcel resource plan and accompanying legislation (HB-10-1365), which enabled Xcel to close four coal-fired units in the Denver region, switch one unit to natural gas, and build a new gas-fired plant to meet federal air pollution standards.[51] The plan, including the fuel supply contract, had to be approved by the Colorado Public Utilities Commission (PUC) and, in particular, it

[51] The Denver *Post*, "Colorado PUC Adopts Plan to Switch Denver-area Power Plants to Natural Gas," 10 December 2010.

provides for cost recovery of payments under the contract regardless of the future gas price trajectory.[52]

Xcel solicited proposals for 10-year natural gas supply contracts to complement the proposed emissions reduction plan. The winning contract, negotiated with Anadarko, contains a fixed price with an annual escalation adjustment. The details are confidential, but Xcel provided a public estimate of the 10-year average nominal gas supply cost at a 29% premium over the prevailing spot market price at the time.[53] The price premium compensates Anadarko for sharing in the future price risk and enabling Xcel to lock in a predictable fuel supply cost to protect customers from gas market price volatility.

The application of this approach to fuel price risk hedging in Hawai'i would require the solicitation of long-term hedge quotes for 10-, 15- and 20-year supply contracts from fossil fuel suppliers or financial intermediaries. The bid price would indicate a fully-hedged fuel supply price and allow direct market comparisons of the avoided cost of hedged fossil fuel energy with the cost of constant-priced renewable energy.

One must rely on approximations, based on simulation or extrapolation, in the absence of market data, for example, if market price data are absent, or if supplier bids cannot be issued or no responses are forthcoming. An alternative analytic approach could be Monte Carlo analysis of fuel price trajectories. The Monte Carlo approach is used in financial risk analysis but its application in energy systems analysis is still relatively new. Monte Carlo methods have not been used to date in avoided cost studies or in VOST analytics.

However, the Northwest Power and Conservation Council (NPCC) has used this approach to analyze the interactions between gas prices and the value of electricity resources in their planning analytics.[54] NPCC accounts for variations in fuel prices and other uncertain inputs, such as loads, hydro output and carbon prices, based on a mix of historic data and estimated ranges for inputs. The NPCC defines the minimum-cost plan as the one that has the lowest median cost, i.e., with a 50% chance of either a higher or a lower cost. They define the minimum-risk plan as the one that has the lowest cost with only a 10% chance of being exceeded and 90% chance of lower cost. The increase in the median cost of the minimum-risk plan over the minimum-cost plan is a risk hedging cost.

The Monte Carlo method analyzes thousands of simulated future scenarios, based on historic fuel price data, to produce a realistic projection of the range of future price volatility. The method follows the following steps:

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[52] State of Colorado, 2010. House Bill 10-1365 *Clean Air-Clean Jobs Act*, Fact Sheet, http://rechargecolorado.com/images/uploads/pdfs/Colorado_Clean_Air_Clean_Jobs_Act_GEO_White0Paper.pdf

[53] EIA, Natural Gas Weekly Update, 15 December 2010

[54] Northwest Power and Conservation Council (NPCC), 2010. Sixth Northwest Conservation and Electric Power Plan, chapter 8, https://www.nwcouncil.org/energy/powerplan/6/plan/

- The historic range of monthly fuel price *changes* is fit to a statistical function (normal or logistic) that describes its variation quantitatively,[55] for example, Figure 6 shows a logistic fit of historic generation fuel price data.[56]
- Use the (normal or logistic) statistical function fit of historic price variation in the simulation of future price trajectories.[57]
- Monte Carlo simulations of 1000 or more random variations on the monthly fuel price changes produce a statistical distribution of the levelized fuel price over a 20+ year time horizon, as shown in Figure 7, where the median value represents the central price forecast.
- Use the statistical distribution of Monte Carlo simulation results to determine the price premium, compared to the median value, that represents the fully-hedged or certain-equivalent value.

The interpretation of this price premium, or the certain-equivalent price, requires judgment and can be done in different ways. For example, the difference between the mean value from the Monte Carlo simulations, which represents the expected value of future prices,[58] and the median value, indicates the price premium that balances the impact of price risks in both upward and downward directions. In the simulation results shown in Figure 7, based on the distribution historic generation fuel oil prices variation in Hawai'i, this premium represents a 22% increase above the median value.

Another alternative, which echoes the way the NPCC uses Monte Carlo risk analysis, is to find the price premium at which a chosen probability (e.g., 10%) of the occurrence of a prohibitive price increase is not exceeded.

The Monte Carlo approach is still relatively new and untested, with few benchmarks, in the valuation of energy resources. However, it offers a method of quantifying the effect of fuel price volatility, compared to a certain-equivalent, which is grounded in historic statistical data and also consistent with long-term expectations of price trajectories. If the market price approach cannot be used, this is a reasonable alternative.

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[55] Treating periodic price changes as the random variable is consistent with the *random walk* theory that is widely used to describe financial market price variations (see Burton Malkiel. 1973, A Random Walk Down Wall Street).

[56] Common statistical distributions such as normal or logistic functions will usually produce a distribution with a wide tail, i.e., uncertainty weighted more toward higher values than lower values (see Figure 6).

[57] If the projection of future prices is outside the range of conventional forecasts (i.e., EIA price forecast for the same future year), based on the central value of the future price distribution, the historic range can be adjusted to fit within the range of long-term fuel price forecasts, by modifying the central value of the future price distribution. However, the statistical *variation* in future prices should still come from the statistical function that was fit to the historic data, for a realistic projection of volatility. This type of adjustment is not necessary with the present historic price variation data.

[58] Expected value is the average of projected prices, weighted according to their probability of occurring.

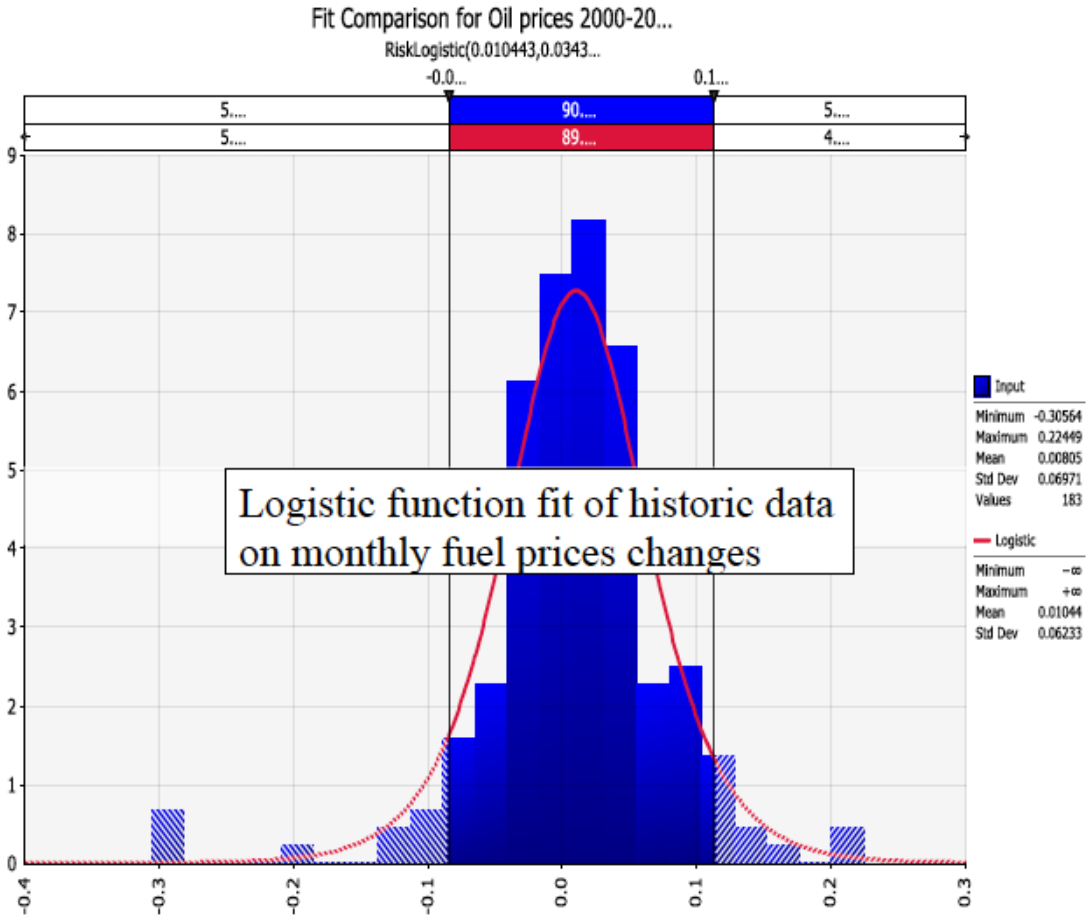

Figure 6. Logistic function fit of historic (2000-2015) monthly price changes for generation fuel oil in Hawai'i

Emission reductions

It is recommended to treat emissions as an avoided future cost, albeit an uncertain one, and not an externality. The valuation and application of externalities is even more uncertain than avoided emission costs and less robust legally.

While the value of emissions is inherently uncertain and, in states without existing emission regulations, speculative, this uncertainty is not fundamentally different from the uncertainty of future fuel prices, which is clearly a necessary component of the valuation method. Any choice of $/ton values will not be theoretically and empirically satisfying. However, an uncertain estimate, based on forecasted future emission price as a proxy, is the preferred alternative to assuming a perpetual value of zero.

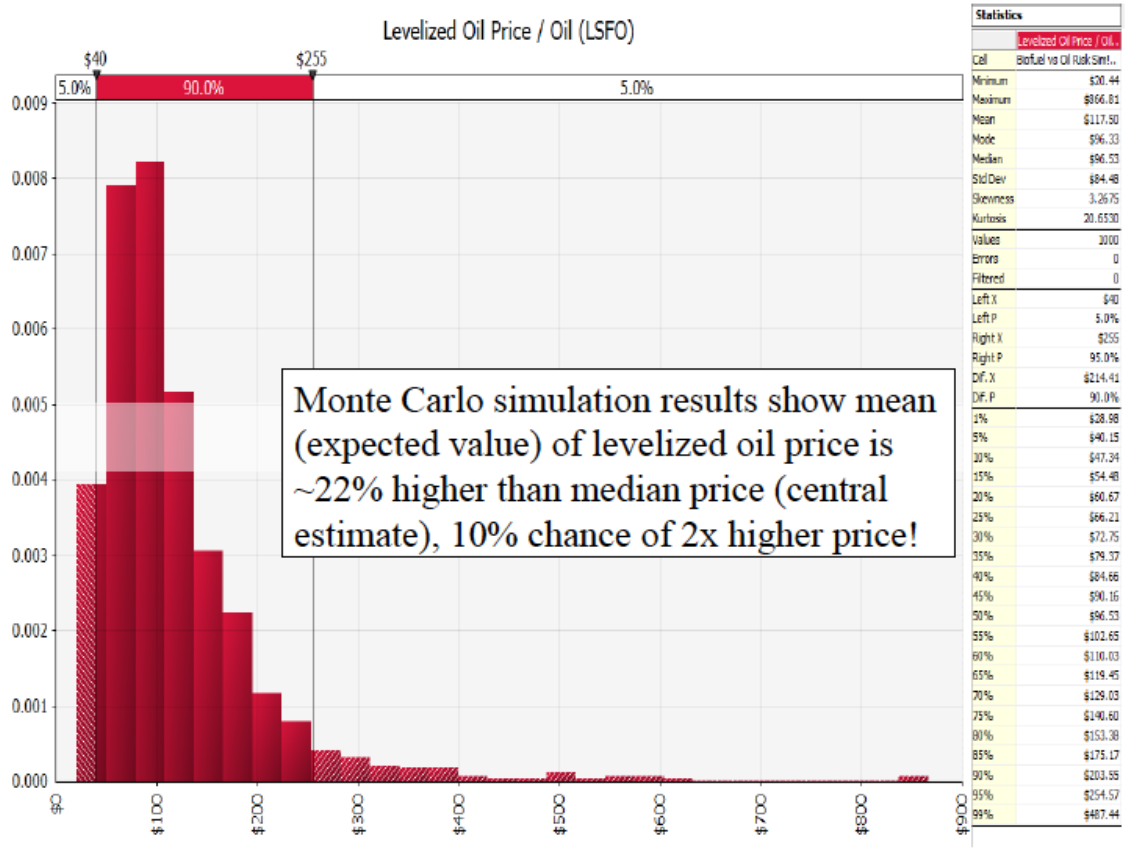

Figure 7. Statistical distribution of Monte Carlo simulation results for levelized generation fuel oil prices, based on logistic function fit of monthly price changes

Also, an externality approach suggests emission valuation based on the potential damage to human health and the global climate, where the range of uncertainty is especially vast. The avoided cost approach is more conducive to emission valuation by proxy, using observed prices from existing markets and other sources. While uncertain, this approach can produce more stable and transparent estimates.

The method for calculation of the emission reduction benefit, as a simple adder to the fuel price, is the following:

Emission value ($/MMBtu added to fuel price) = Emission rate (kg/MMBtu of fuel input) * emission cost ($/kg)

As observed above, the value of CO2 emissions tends to dominate the results, even with a conservatively low estimate of carbon price, as other emissions such as NOx and PM-2.5 are unlikely to reach a comparable value. The E3 avoided cost method for California includes NOx, PM-2.5, etc., but all of their values are insignificant compared to that of CO2, which began at $8/tonCO2 and escalated gradually until replaced by prices from

the state's carbon market that opened in 2013 under the AB-32 GHG reduction law.[59] Similarly, the Minnesota VOST method and other CPR value of solar studies produce criteria pollutant values that sum to the equivalent of less than $1/tonCO2.[60]

For CO2, at the Federal level, the US Environmental Protection Agency (EPA) endorses a social cost of CO2 emissions with a value of $38/tonCO2.[61] Since this value is much higher than the emission prices in any current carbon market, it could be regarded as a price level to which future market prices might rise, but probably an unrealistic present value (though more realistic than zero).

As an intermediate approach, one could apply a similar method as the California avoided emission cost model to an unregulated market today. A reasonable starting value would be intermediate between the California AB-32 carbon market (now about $12/tonCO2) and the northeastern Regional GHG Initiative (RGGI) prices (now about $6/tonCO2), or a simple median value of $9/tonCO2, escalating at 4-5% per year. Once an active carbon market or emission tax is in place, its value would then replace the estimated value.

Electric energy-related benefits: recommended methods

Avoided energy costs are the most important component of the renewable electricity benefits. Annual avoided electric energy cost is the weighted average of the product of the avoided fuel cost and hourly renewable generation and marginal generation heat rate values. For central renewable generation sources, which feed power into the T&D grid, the full value of the avoided electric energy cost is the following:

Avoided electric energy cost ($), hour i

= Renewable production, hour i * Avoided fuel cost ($/MMBtu)

* Heat rate for marginal generator (MMBtu/MWh), hour i

Using this calculation to estimate the value of each hour's renewable production, the hourly values are then summed to determine the annual value of avoided energy cost.

Avoided electric energy cost ($/MWh), year n =

$$\frac{\text{Sum [hourly avoided cost (\$), for all hours i = 1-8760]}}{\text{Sum [renewable production (MWh), for all hours i = 1-8760]}}$$

[59] E3 and RMI, 2004, *op. cit.*
[60] CPR, 2014, *op. cit.*
[61] US EPA, 2013, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

The annual value of avoided cost is essentially an average of all the hourly values per kWh, weighted according to the hourly renewable production. Annual values are then levelized over the investment lifetime, using the appropriate discount rate, usually the utility WACC. First, the future annual avoided cost values are converted to an equivalent present value, and then this present value is converted to an equivalent annual value, using the Capital Recovery Factor.[62]

Levelized avoided energy cost =

Sum [avoided cost, year n / (1 + discount rate)^n for all years in the investment lifetime]

* Capital Recovery Factor (for the applicable discount rate and investment lifetime)

Avoided energy losses

Use of a simple annual average loss rate is recommended. If hourly loss rates, as a function of load, are available, they can be applied to hourly energy cost values, as the Austin Energy and Minnesota VOST methodologies do. However, the annual average loss rate can be used with little loss in accuracy. Note that avoided losses apply to distributed, on-site renewable sources.

Thus, the full value of the avoided electric energy cost, for a *distributed renewable source*, is the following:

Avoided electric energy cost ($/MWh), year n =

$$\frac{\text{Sum [hourly avoided cost (\$), for all hours i = 1-8760]}}{\text{Sum [renewable production (MWh), hours i = 1-8760] * [1 – average \% T\&D loss rate]}}$$

Marginal heat rate

Identification of the marginal generation unit and its heat rate, on an hourly basis, is a key step in an avoided energy cost methodology, because it provides both the value of the heat rate and, in cases where the marginal fuel could vary, and the type of fuel used, which in turn determines fuel price, emission cost, etc.

The recommended approach, which is rather detailed and complex, is to simulate the hourly operation, or dispatch, of the generation fleet on an hourly basis. The simple approach, using on-peak/off-peak assumptions of marginal plants, does not appear to be

[62] The Capital Recovery Factor (CRF) is the ratio of an annuity to its equivalent present value, depending on the discount rate and investment life. The CRF can be obtained from tables of financial functions, as a function on a financial calculator, or from Excel using the function =PMT(discount rate, investment life, -1).

sufficiently accurate, given the heterogeneous generation mix in Hawai'i. Also, use of real-time electricity market prices is not an option.

The marginal fuel and heat rate, on an hourly basis, are defined as those of the generation unit that is at the margin in a given hour.[63] This unit is generally the highest variable-cost generation unit that is needed to meet the hourly load at minimum cost, under the assumption of least-cost economic dispatch of generation. However, it is more realistic, especially in a small system such as on the islands, to apply a security-constrained, least-cost dispatch rule. In this case, generators have minimum-output thresholds and some are run somewhat out of order in terms of variable cost, in order to maintain system stability.

The hourly marginal unit is determined using a production cost model such as UPLAN (the model used by KIUC) or a stacking model, such as the one built by E3 for the PUC to model KIUC and the HEI utility companies. A stacking model needs to be calibrated against real operation to simulate a realistic security-constrained, least-cost dispatch rule.

The generation stack and hourly marginal heat rates should be determined for the current generation fleet and projected into the future, over the full investment lifetime, following the utility's reference-case generation expansion/retirement plan, i.e., the expansion planned that is considered the most likely to be implemented in compliance with state PUC (and KIUC governance) rules. The most detailed model would update the fleet every year, but it is also reasonable to use intervals of up to five years (not more) and interpolate between these time steps.

To establish a process to determine marginal generation source(s) for the avoided cost analysis, the most practical approach may be to adopt the framework of the E3 avoided cost model. Its baseline scenarios and method for hourly determination of marginal generation sources are a good start and have already been vetted by the PUC and the utilities. It should not be difficult to adjust its assumptions for fuel price, emissions, hedge value, etc.

These adjustments would allow for updating of assumptions and making them consistent with the views of the HEPF. For example, one might adjust the fuel price inputs to include adders for emissions and hedge value, as recommended above. Since these cost terms can be represented as simple adders to the fuel price, their inclusion in an updated model would not complicate the model's design, structure or operation.

This approach assumes that the PUC would be able to post the updated model and/or allow external use of such a model. The existing model was not designed with this purpose in mind and would surely need to be modified to make it work as proposed here, and possibly to secure any sensitive data that is not intended for public circulation. These appear to be soluble problems.

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[63] To be more precise, the marginal heat rate is that of the marginal generation unit, operating at the specific level of production needed to meet a given hourly load.

Despite the voluminous detail of a production-cost model or an hourly stacking model, it is important to recognize that even a very detailed model is still only an approximation. This is especially true in modeling the future generation stack, as loads, the generation resources themselves and the system expansion plan can change. In particular, a key force driving such changes is the growth of renewable generation, which can change the resource that is at the margin and might affect the choice of resources that are built.

Moreover, if the reference-case expansion plan is likely to change significantly, this type of analysis is more approximate still. In Hawai'i, the prospect of introducing LNG-fired generation could completely change the definition of the marginal source, its fuel type, heat rates, emissions, etc. Repowering or replacement of existing generation units with gas-fired generation would put LNG on the margin, changing the marginal heat rate, fuel cost and carbon content for many or all hours of the year. A major shift to LNG would tend to reduce avoided energy values, due to lower fuel costs, marginal heat rates and emissions. On the other hand, such a shift could also result in higher capacity costs for new generation investments.

Thus, to construct a stable estimate of renewable energy benefits, one needs a stable reference-case plan. One potentially helpful result of the on-going integrated resource planning and PSIP processes would be to converge on a consensus, reference-case resource plan that the HEPF cold endorse. The generation capacity and fuel assumptions of such a plan could provide a more confident basis on which to estimate avoided costs and benefits of future renewable generation.

Energy-related benefits: application

Avoided fuel-related energy costs are the largest, often dominant, component of avoided electricity cost and VOST calculations. Therefore, uncertainties in this calculation have a magnified effect on the uncertainty of the overall result. The main challenge in estimating avoided fuel and other energy-related costs is to determine the hourly marginal fuel type and generation heat rate. Once these are known, the value of avoided fuel cost and losses, as well as fuel price hedge value or avoided emissions value, can be estimated simply.

Widely-used avoided cost methods (e.g., E3 models) and the Austin Energy and Minnesota VOST methods use a levelized value of future energy costs, as described above. This provides a stable benefit value against which to compare the levelized cost of renewable generation, or to formulate payments for renewable production.

Since renewable energy is nearly a constant-price resource, once the capital investment is made, the appropriate avoided energy cost comparison should be against a constant value that represents the levelized future energy cost over the investment horizon, ideally including the fuel price hedge value. The Minnesota VOST method converts a levelized value to a price function with 2.5% annual inflation, with its present value (discounted at utility WACC) equal to the uniform, levelized value.[64]

[64] CPR, 2014*, op. cit.*

In principle, a VOST or renewable tariff that changes predictably over time could be workable. However, a renewable tariff that floats, for example according to an index of future fuel prices, would be less predictable than traditional tariff terms, which would increase the financial risk of the renewable investment.

At a more fine-grained scale of time variation, the expected hourly variations in avoided energy costs could be captured by a time-varying approach to valuation. Such a valuation would reflect heat rate variations that drive avoided energy costs, as well as differences in renewable system performance, such as the benefit of tracking or west-facing solar collectors to increase afternoon, peak-coincident production.

These hourly variations can be modeled in a way that produces stable avoided cost or benefit values over the investment time horizon. Hourly solar performance for a specific weather year can be predicted reliably in advance, for any given orientation or tracking strategy, as can wind resource variations. These variations can be matched with hourly avoided cost variations to appropriate weight the hourly renewable output and its contribution to energy value in a given year. Although the actual individual hourly values vary, the annual sums of hourly avoided cost, as defined above, are relatively stable.

Renewable energy developers generally have sufficient modeling capability to forecast hourly performance confidently. Therefore, they should be able to adapt to time-varying valuation, provided that this valuation is stable over their investment time horizon. Time-varying tariffs could be designed to reflect the benefits of renewable generation more accurately than a flat tariff, and they could therefore provide true performance incentives to producers. On the other hand, use of time-varying valuation and tariffs would require advanced utility metering.

In summary, variations in the energy-related benefits of renewable generation can be modeled and predicted with confidence, such that the total benefit value could be adjusted, if necessary, to reflect variations in, for example, solar orientation or wind siting. For non-dispatchable renewable sources like wind and solar photovoltaics, it is unclear whether including such variations in a tariff paid to renewable owners would be needed as a performance incentive. Operational incentives would be stronger for potentially dispatchable sources, such as biomass-fired generation or sources with integrated energy storage.

The other dimension of time variation in renewable energy benefits would be the longer-term variation as values of fuel prices and other parameters change. One could argue that a tariff that floats according to an index of, for example, future levels of fuel prices would reflect benefits more accurately. But, as observed above, payment terms that are less predictable than traditional terms could increase financial risk of renewable generation.

Electric capacity-related benefits: recommended methods

Avoided capacity costs tend to be relatively important in the estimation of renewable energy benefits, when one or more of the following conditions applied:

- Growth-driven capacity expansion is strong
- Fuel costs are relatively low
- Peak demands coincide with renewable production, result in high ELCC values

In Hawai'i, with modest load growth, high fuel prices, and evening demand peaks, avoided capacity costs appear unlikely to contribute a large component of the economic benefit of renewable energy. Rather, avoided energy-related costs are likely to dominate. However, some renewable generation options, such as baseload or dispatchable biomass-fired power on Oahu, could have a significant capacity-related benefit.

The basic form of the capacity cost calculation is the following:

Marginal cost of capacity ($/kW-year) =

Marginal fixed O&M costs ($/kW-year) +

Levelized value of Sum [Marginal capital cost of generation, T&D, reserve capacity] ($/kW-year)

The levelized capital cost values are simply the product of the investment cost, in $/kW, and the Capital Recovery Factor, for the applicable discount rate and investment lifetime.

If supply capacity is adequate at present, the capacity cost values (except for O&M) should first be discounted by the number of years until new capacity is needed, and then levelized. If supply capacity is adequate indefinitely, such that there is no need for capacity additions, then the avoided capacity cost is just the marginal O&M costs, which in this case would be that of the marginal *existing* generation source.

The extent to which the marginal cost of capacity contributes to avoided costs and thus benefits of renewable generation depends on the capacity value of the renewable source, which is measured by the effective load-carrying capacity (ELCC), as a fraction of rated AC capacity.[65] Thus, avoided capacity cost is the product of marginal cost and ELCC, and its annual value, before being allocated to all of some of the annual kWh of renewable energy production, is the following:

Annual avoided capacity cost ($/year) =

Marginal cost of capacity ($/kW-year) * Renewable rated AC capacity (kW) * ELCC (%)

Finally, the avoided capital cost is allocated to each kWh of annual renewable production. It can either be allocated equally to all kWh of annual production:

[65] For solar photovoltaics, the AC capacity is the rated DC capacity at 1 kW/m^2, adjusted for inverter efficiency and other losses. The value is typically 72% of DC capacity.

$$\text{Avoided capacity cost (\$/kWh)} = \frac{\text{Annual avoided capacity cost (\$/year)}}{\text{Annual renewable production (kWh/year), for all hours}}$$

Or, avoided capital cost can be allocated selectively, to kWh of energy produced during times of high net load that contribute to capacity needs.

$$\text{Avoided capacity cost (\$/kWh)} = \frac{\text{Annual avoided capacity cost (\$/year)}}{\text{Annual renewable production (kWh/year), that contributes to capacity}}$$

There are various approaches to allocating capacity value and therefore avoided capacity costs to specific hours of the year, and for weighting some hours more than others (while many hours receive zero weight). These details are discussed below.

Renewable capacity value

In order for renewable generation to avoid conventional energy generation capacity, the renewable source must reliably deliver power during the hours of the year when net loads are highest and drive the need for capacity expansion. The recommended method of estimating the contribution to capacity by a renewable source is to determine the ELCC.

Other methods to estimate renewable capacity value, such as taking the renewable capacity factor in top load hours or top hours of loss-of-load expectation (LOLE), are not recommended. However, for geothermal and biomass-fired generation, simple methods are adequate and typically indicate 80-100% of rated capacity as the capacity value.

The ELCC is the net thermal capacity that is displaced by a renewable source, while meeting the same annual load and maintaining constant reliability, typically measured by LOLE. Since wind power output varies and may not coincide with peak demand, ELCC values in the literature are in the range of 5-30%.

The HEI PSIP assumes an ELCC of 10% for wind on Oahu and Hawai'i islands, but only 3% on Maui. This low value is attributed to the high wind penetration there and its lack of geographic diversity.[66]

[66] Hawaiian Electric, Maui Electric, Hawai'i Electric Light Companies, 2014. Hawaiian Electric Power Supply Improvement Plan, http://files.hawaii.gov/puc/3_Dkt%202011-0206%202014-08-26%20HECO%20PSIP%20Report.pdf

Generation from solar also varies, and it tends to coincide with summer peak loads in most mainland utilities, although not during the midday hours of peak solar production. As a result, ELCC values in the literature are in the range of 30-70%.

Figure 8 illustrates this relationship for a mainland utility, in a way that is instructive for the Hawaiian context. At the time of peak demand, the solar production is about half of the maximum (noon) output, suggesting an ELCC of about 50% for the first MW of solar production. As solar production increases, the peak net load, customer load minus solar output, decreases and occurs later in the afternoon. When solar production is sufficient to shift the net load peak into the evening, as shown in Figure 8, the load reduction is less than one-third of the maximum solar output (i.e., ELCC of ~30%).

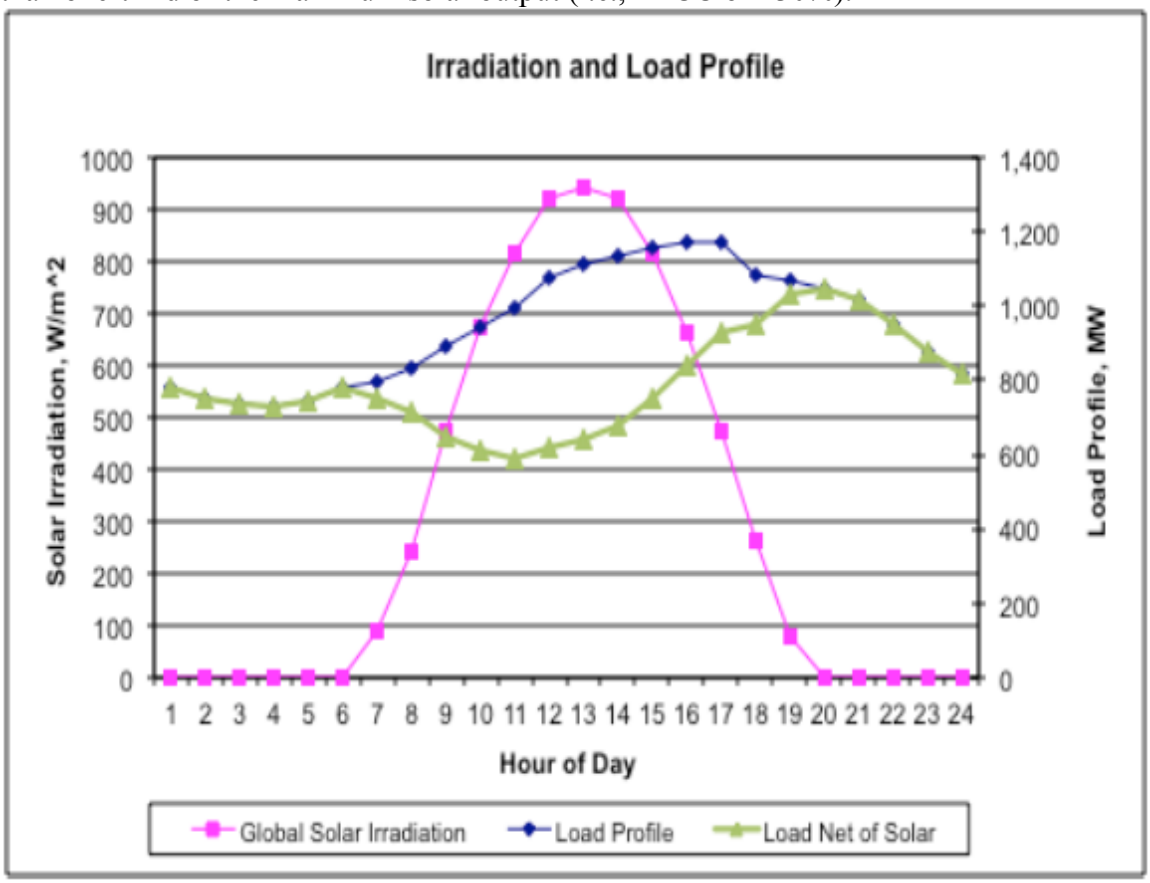

Figure 8. Hourly solar production and load profile for a mainland utility

In this case, with peak net load already shifted into the evening, any additional solar production would have no further effect on net peak load. This illustrates the tendency for ELCC and thus capacity value of incremental solar generation to decline with increasing solar penetration, to essentially zero.[67] This case is effectively the baseline situation in Hawai'i, where peak demand occurs during evening hours and solar generation has little impact on peak demand, resulting in low ELCC estimates.

[67] Mills, A., and R. Wiser, Changes in the Economic Value of Variable Generation at High Penetration Levels, http://emp.lbl.gov/sites/all/files/lbnl-5445e.pdf

The HEI PSIP assumes an ELCC of zero, which is explained by the evening occurrence of the system peak demand.[68] In the E3 avoided cost study, capacity credit, and therefore avoided cost, is allocated to the top 500 annual load hours, which indicates a non-zero capacity value for distributed solar generation on Oahu, according to that method.

Particularly with regard to solar generation, the ELCC value depends on system design. For example, tracking or west-facing collectors can increase afternoon peak-coincident collection, although this benefit is negated if the peak occurs after sunset. For systems with relatively high avoided capacity costs, it is important to capture differences in value between different designs or orientations.

If the current ELCC values for solar and wind are as low as the HEI companies indicate in the PSIP documents, there would be minimal value in developing detailed analytics of avoided capacity value for these variable generation sources. Therefore, the ELCC analysis should be reviewed under the most up-to-date assumptions.

If ELCC values are found to be higher, and in any case for geothermal and biomass-fired generation, the ELCC should be periodically updated as the penetration of renewable generation increases. In the future, there will be a greater chance that renewable energy will be at the margin, i.e., will be curtailed in certain hours, a lesser chance that it will offset conventional generation capacity, and probably a lower ELCC.

Avoided system generation and transmission capacity costs

Generation capacity cost is the capital cost of the next generation plant that will be built in order to meet new load growth, if any, divided by its capacity. This definition does not apply to generation plants that would be needed for reliability, ramping or ancillary services only, because such capacity would generally not be avoided by adding renewable generation, regardless of its peak coincidence or ELCC value.

The transmission capacity cost can be estimated as the portion of capital cost of transmission expansion that is attributed to load growth, if any, divided by incremental load growth. For Hawai'i today, transmission capacity costs generally appear small.[69]

Today, load growth on Oahu implies a significant capacity cost, but on the other islands load growth is low, existing capacity is more than adequate, and thus avoided capacity costs appear to be insignificant. If fuel oil remains the principle source of generation fuel, then one can expect generation capacity needs to be modest and mostly on Oahu.

However, the current reference case plan is not the only plausible plan in Hawai'i, as there is also the possibility of replacement or repowering of oil-fired generation capacity with LNG, which could change the avoided capacity resource. If there is a major shift to LNG for generation, the capacity value would be more uncertain and possibly

[68] Hawaiian Electric PSIP, 2014, *op. cit.*
[69] E3, 2014, *op. cit.*

higher, due to the prospect of building or renovating generation capacity, some of which could potentially be avoided.

On the one hand, modification of existing generation units to enable dual-fuel (oil/gas) operation would have minimal effect on incremental capacity and marginal capacity costs, probably just an incremental increase in the marginal O&M costs. On the other hand, replacement of existing oil-fired generation units with more flexible gas-fired combustion turbines would put LNG gas-fired capacity on the margin, driving the marginal capacity cost. The Hawai'i PUC has identified increased flexibility of the generation fleet, to provide faster ramping to balance variable renewable output and reduce curtailment, as a priority for the utilities.[70]

If part of the replacement LNG gas-fired capacity depends on the magnitude of (net) load, some of this capacity could potentially be avoided by renewable generation's contribution to capacity (if any). In this case, LNG gas-fired capacity would become the marginal generation capacity for estimating avoided capacity cost, the value of which would surely increase compared to the reference case with oil-fired generation only.

Therefore, one of the advantages of developing a clear long-term resource plan would be to clarify the marginal generation capacity, which drives both the avoided capacity costs and the avoided energy costs. For example, if LNG does replace some amount of oil-fired generation capacity, it would likely reduce avoided energy costs while increasing avoided capacity costs, compared to the current reference case.

Marginal distribution capacity costs (MDCC)

The MDCC is properly estimated as the annual deferral value of the local area distribution capacity expansion plan, divided by the annual local area load growth.[71] The conditions that would drive significant deferral value in a specific utility distribution planning area are the following:[72]

- Major components such as a substation at or near maximum capacity
- Area capacity expansion planned in the near future, but not already committed
- Lack of other options, e.g., alternate network connections, to meet load growth
- Steady, but not rapid, load growth in the area[73]
- Distributed generation output reliably coincides with local area peak demand
- Distributed generation scale sufficient to meet at least one year's area load growth

[70] Hawai'i PUC, 2015. Staff Report and Proposal, Docket 2014-0192
[71] Orans, 1989, *op. cit.*
[72] Swisher, J. and R. Orans, 1996. The Use of Area-Specific Utility Costs to Target Intensive DSM Campaigns, *Utility Policy*, vol. 5, pp. 185-197, http://www.sciencedirect.com/science/article/pii/0957178796827913
[73] Ironically, rapid area load growth tends to absorb new distribution capacity quickly and thus results in relatively modest MDCC values compared to more modest area growth.

The MDCC value tends to be highly utility- and location-specific, as noted above. Its value is generally rather small, except in exceptional situations, and it may be zero or even somewhat negative in distribution planning areas that have circuits with high renewable penetrations. Costs of additional distribution investments needed to support distributed solar, for example, could more than offset any MDCC deferral value.

Therefore, inclusion of MDCC estimates as a renewable energy benefit is *not* recommended. There is something of a mismatch between the type of distributed renewable resources that could confer MDCC value and their expected performance in Hawai'i. Distributed solar may be as likely to increase distribution costs as to defer them. Other renewable sources, including wind and biomass, are most likely to be sited upstream of the distribution system, where they cannot contribute to distribution capacity.

Capacity value of avoided losses

Again, this category of potential renewable benefit only applies to distributed sources, ad it requires them to provide capacity value, which appears to be an unlikely fit in Hawai'i. Use of the peak loss rate is recommended. If hourly loss rates, as a function of load, are available, the peak hour loss rate can be applied directly to the avoided capacity cost, for distributed renewable sources that have significant capacity value. Otherwise, annual average loss rate divided by annual load factor is an adequate estimate for the peak loss rate.

Ancillary services

Like MDCC values, ancillary service benefits are highly uncertain, appear to be generally small, and may be zero or slightly negative at high renewable penetrations. Renewable generation can cause increases in ancillary services costs that are on the same order of magnitude as the benefits. A small ancillary service value with a large uncertainty is unlikely to be significantly different from zero, and the RMI meta-study of renewable energy benefits shows the few literature estimates of ancillary service value to be minimal or negative.[74] Therefore, inclusion of estimates of avoided ancillary services as a renewable energy benefit is *not* recommended.

Note that this high uncertainty and questionable value could change as technology advances in the near future. In the pursuit of greater flexibility of the electric grid and generation fleet, power engineers and planners are finding that our existing suite of ancillary service products are not an ideal fit to the new problem. Rather, new ancillary service products need to be designed, motivated mostly by the challenges of balancing ever more variable renewable output.

Upward and downward ramping events, daily for solar and somewhat more random for wind, result from time variation in renewable output at relatively high penetration, which is not well aligned with the time variation of the utility load profile. Indeed, load and renewable variations can compound each other to cause a steep *net load* ramping event.

[74] RMI, 2013, *op. cit.*

Today's ancillary services are not a good fit for the flexibility services needed to balance such ramp events due to variable renewable generation. Compared to regulation services, ramp events caused by renewable-load variation are less frequent, more gradual, and more prolonged. Compared to contingency events for thermal generation, renewable-load ramp events are more frequent, more gradual, more prolonged and more predictable.[75] As a result of this mismatch, the Independent System Operators (ISOs) in both California and the Midwest are developing new ancillary service products for ramping.

Capacity-related benefits: application

For Hawaiian utilities, unlike some mainland utilities, avoided capacity costs are a minor component of avoided cost or VOST calculations, especially when they are applied to wind and distributed solar generation. In Hawai'i, high fuel costs, relatively low ELCC values for wind and solar, and uncertain need for generation capacity expansion to meet load growth (rather than for system stability and reliability) all reduce the likelihood that capacity costs for wind and solar will be sufficient to justify the considerable difficulty of accurate valuation.

On the other hand, the avoided capacity cost value is relatively simple to determine for baseload or dispatchable sources, such as geothermal and biomass-fired power, as a simple estimate of the ELCC can be taken from the ratio of a plant's annual availability to that of a fossil fuel-fired plant. For these technologies, the result is more likely to be a significant value.

Demand-side resources, such as demand response (DR) programs that shift loads in time, typically away from the hours of maximum demand, can be planned in combination with renewable generation in a portfolio of distributed resources. If the DR action is triggered when the load, net of the renewable output, is maximum, the combined portfolio appears to have significant capacity value, beyond that of the renewable source alone.

While the DR-renewable portfolio can indeed provide capacity value, the incremental capacity of the portfolio would generally be all or nearly all attributable to the DR capacity, with or without the renewable contribution. An exception might be a case with a very long, flat peak when neither DR nor renewables alone could shift load for a long enough duration to provide capacity benefit.

Generally, however, it is best to consider DR as a capacity resource separate from the energy and any capacity provided by renewable generation. Another reason to keep the analysis of the two resources separate is that DR program benefit depends on correct operation *in response to the utility's signal*, so its performance is not really integral to the performance of the customer-sited, must-run renewable generation system.

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[75] Milligan, M., B. Kirby, 2010. Market Characteristics for Efficient Integration of Variable Generation in the Western Interconnection, http://www.nrel.gov/docs/fy10osti/48192.pdf

Allocation of avoided capacity cost to energy produced

Once annual avoided capacity cost, in $/year, has been determined, this value needs to be allocated to the renewable energy produced, in kWh/year, if it is to be applied through an energy-related credit (rather than as a separate attribute). The simplest approach is to divide avoided capacity cost by annual production. The result is that each kWh produced during the year is allocated a uniform capacity benefit value. This approach is used in the Austin energy and Minnesota VOST methods, which estimate a levelized value of avoided capacity cost, based on the chosen ELCC value, and divide by the annual renewable production, to obtain a uniform value per kWh.[76]

This simple approach is consistent with the structure of bilateral power purchase agreements (PPAs) that utilities negotiate with customers like Apple, Facebook and Google, which procure large renewable generation assets. The negotiated PPA price can reflect utility system benefits, including capacity, which depend on siting and design parameters such as solar orientation. However, once the benefit of these attributes is negotiated into the PPA tariff, payment is generally at a constant tariff per kWh.

The E3 avoided cost methods use a more complex approach. They allocate avoided capacity cost to the top 100-500 load hours, which results in very high $/kWh values for these specific hours, and all other hours are allocated zero capacity value. For the top load hours, the capacity values are added to varying hourly energy costs to give full avoided cost values on an hourly basis. The hourly avoided cost values are then matched with hourly renewable output (assuming the hourly utility load and renewable resource data are available from the exact same year) to provide full hourly valuation. For Oahu, using a 500-hour allocation of capacity cost, the E3 avoided cost study reported a modest, but non-zero avoided capacity cost value.[77]

If time-varying valuation were used for avoided energy costs, then a capacity cost component could be added to hours when net maximum loads occur, to arrive at an hourly set of full avoided cost values. Although individual hourly values would vary, the annual sums of hourly avoided cost could be reasonably stable, if the hourly allocation pattern is unchanged. If this type of time-varying valuation is stable over time, renewable energy developers should be able to forecast hourly performance confidently and adapt to this structure.

Use of time-varying valuation and tariffs would require advanced utility metering, but it is not necessary to wait for advanced metering to capture the value of energy-related benefits accurately. Even if one uses the E3 hourly allocation approach to calculating the avoided capacity cost, the results can be applied to a single $/kWh value that is applied to all renewable output during the year, at least until advanced metering is implemented.

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[76] CPR, 2014, *op. cit.*
[77] E3, 2014, *op. cit.*

Also, as discussed above, time-varying renewable tariffs that float, for example according to varying capacity costs over time, would be less predictable than traditional terms. This uncertainty would increase financial risk of renewable generation.

Other benefits: recommended methods

The other categories of renewable energy benefits have not been fully implemented in existing programs, so there are not really best practices yet. However, at least for local economic development, there may be potential applications.

Local economic development

There is no available methodology that could be adopted as best practice for valuing the local economic development benefit of renewable energy. In order to include this category of benefits, additional research and methodological work will be needed to define the benefit, select a method and input values (most likely from an input-output model), and adapt the method to the local context. Because the economic development benefit is a very uncertain analytic challenge, it is unlikely that a theoretically and empirically satisfying result will be obtained. Only a rough estimate should be expected.

Nevertheless, it is recommended that further methodological and analytic work be carried out, with the goal of producing a reasonable, albeit uncertain, estimate of the local economic development benefit of renewable energy. As in the case of avoided emission costs, an imprecise estimate that is within the range of plausible values may be superior to assuming implicitly a perpetual value of zero. This benefit may be important specifically in the Hawaiian context, due to the nature of the island economy where generation fuel is 100% imported.

The first challenge is to define the metric for economic development. While a key motivation for valuing economic development is typically employment-driven, jobs are not the most appropriate indicator of value. To be useful, a jobs metric would need to be converted to a dollar-based metric for comparison with other benefits and costs. More importantly, a jobs metric implies that many low-paying jobs provide greater benefit than fewer high-paying jobs. However, low-paying jobs imply lower productivity and therefore value, so jobs alone would not be the best metric, even if it had the right units.

Rather, it is more practical to consider a value such as total local economic output or employment income. It is nevertheless unclear how to best characterize local economic development as a benefit to be valued – should one consider economic output, incremental gross state product, net labor income, tax revenue or another value?

Following the methodology used to estimate economic development impacts of energy efficiency programs, the local economic development value results from the following:

- Changes in local economic activity caused by investment in renewable energy,
- Avoided expenditures for fossil fuel imports for power generation, and
- Changes in customer purchasing power.

For each of these changes in expenditures, the change in local economic activity can be estimated as the change in expenditure multiplied by its fraction of local (vs imported) content and an economic multiplier, typically taken from input-output models of the local economy. These multipliers are categorized as a type I multiplier, which includes the direct expenditures and the indirect impacts in the supply chain of goods and services, or a type II multiplier, which also includes induced expenditures of earnings by households. Effects on household expenditures are relevant, so type II multipliers are recommended.

The fraction of local content can be estimated using the Jobs and Economic Development Impacts (JEDI) models from NREL. There is a JEDI module for each renewable energy technology, including distributed solar, onshore wind, geothermal, biomass-fired power, and ethanol production.[78] Application of the models in Hawai'i could increase the models' uncertainty, but they do provide an internally consistent set of metrics, and each model offers the selection of Hawai'i as the project location.

In order to estimate net economic impact, it is necessary to estimate the output or income lost due to reduced fossil fuel use, which partly offsets gains from expenditures on renewables. For example, the JEDI models from NREL also include a petroleum module that one can run for Hawai'i. For example, if one assumes that fuel savings avoids only operating costs of local refinery facilities, and not the construction of refinery capacity, the JEDI model with default Hawai'i inputs indicates that each barrel of oil generates about $3.5 in economic output and $1.3 in labor earnings, or about $0.57 in economic output and $0.20 in labor earnings per MMBtu of fuel energy.

General economic multipliers are estimated for Hawai'i by DBEDT, and the most recent set of multiplier tables are from 2007. Depending on which economic sector activity occurs in, the type II multipliers for total economic output range from 1.5 to 2.2, and those for earnings range from 0.2 to 0.8. Construction, which could encompass much of spending on renewables, has multipliers of 2.08 and 0.6 (similar to those extracted by Loudat), and utilities have multipliers of 1.74 and 0.22. Economy-wide average multipliers are 1.9 and 0.7.[79]

Other potential sources for local economic multipliers include those used in the articles such as that cited above by Loudat or the NextEra/HECO testimony by Reed, both based on statewide input-output models, as well as models used in economic research by UHERO, which are based on statewide general equilibrium models. In order to build an internally consistent methodology, it is necessary to derive local economic multipliers, using consistent definitions and assumptions, for the impact of renewable energy expenditures, avoided fossil fuel costs, and changes in customer purchasing power.

Using these sources as inputs, and acknowledging the large uncertainty that is inherent in these calculations, the most basic form of the net local economic impact, in $/kWh, would be the sum of the following three terms:

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[78] http://www.nrel.gov/analysis/jedi/download.html
[79] DBEDT 2013 at http://dbedt.hawaii.gov/economic/reports_studies/2007-io/

Economic development value =

Renewable investment: (M-re * %local-re) * levelized renewable investment cost

– Saved fossil fuel energy: (M-ff * %local-ff) * (full avoided cost)

– Net customer expenditure: (M-0 * %local-0) * (levelized renewable cost – avoided cost)

where:
- M-0 is the (type II) local economic multiplier for final demand, i.e., consumer spending
- %local-0 is the local content fractions for final demand
- M-re, M-ff are local economic multipliers for renewable and fossil fuel energy
- %local-re, %local-ff are local content fractions for renewable and fossil energy, and
- Note: the quantity (M * %local) may be reported as a combined value in some models

The renewable investment is a levelized value in $/kWh to enable attribution to energy produced in kWh. The saved fossil energy cost is represented as the full avoided cost from the perspective of the energy supplier, and is also a levelized value in $/kWh.

The net change in customer expenditure can be a net saving (negative value), which adds to net economic development value via the resulting increase in customer purchasing power. Otherwise, if energy expenditures increase, the reduced purchasing power causes a local economic loss. The latter case is more likely in states with low energy costs.

To fill in missing multiplier values, it may be reasonable to use the same multiplier value for system investments, saved fossil energy and/or customer expenditures, assuming these multipliers are separate from, not combined with, the local content fractions. Given the large uncertainty in the estimation of local economic multipliers, potential errors from differences in the estimated values may be small compared to the overall uncertainty.

Assuming that total customer energy costs change little if renewable sources replace fossil fuels, then the main local economic development impact of renewable energy in Hawai'i is likely to be the value in the local economy of avoided fuel imports, which allow local expenditures to be recycled locally, rather than being lost to the state.

Security related benefits

For security related benefits, the existing valuation methodologies mentioned above have not been able to quantify a security benefit that was meaningful. It therefore appears that creating a new application for Hawai'i would require additional information. At present, it does not appear feasible to include this category in the valuation of renewable benefits.

<u>Other benefits: application</u>

Given the elevated uncertainty of these categories of value, their application should be kept as simple and transparent as possible. The simplest approach is to treat each term as

simply an added to the avoided energy cost. Such values should be levelized and applied as an adder to the value of each MMBtu or kWh of renewable energy output.

Outstanding Analytic Issues Regarding Avoided Costs and Renewable Valuation

The following are methodological issues that are likely to be relatively uncertain and potentially influential in the overall valuation result (therefore uncertainty matters).

First, the potential curtailment of surplus renewable generation, as renewable penetration increases in the future, will impact avoided costs and the valuation of renewable benefits. If curtailment increases in the future, this will reduce avoided costs by replacing fossil fuel with (free) renewable energy as the marginal source during certain hours. It will also reduce the ELCC and resulting capacity value of all renewable sources.

As the estimation of avoided costs and the determination of the marginal generation source is refined in the future, based on updated utility resource plans, the potential for increased curtailment will have to be considered. On the other hand, greater application of flexible generation technology, demand response, flexible loads such as plug-in vehicles, and possibly dedicated energy storage, has the potential to make the future power supply system more flexible, moderating the need for curtailment and maintaining the value of renewable generation.

Note that the reduced value of avoided costs, due to increasing curtailment, should only affect valuation of new systems at that time, and possibly in the future, but not those systems already in place. The avoided costs of existing systems should be maintained at the values determined from the marginal sources at the time of their installation.

Second, the possible future conversion of existing oil-fired generation sources to LNG could impact utility resource plans, avoided costs and renewable valuation. Depending on the extent to which LNG is developed and deployed in the power sector, it could re-order the generation dispatch stack on each island where it is used. As shown in the E3 avoided cost results for Oahu, LNG has the potential to reduce avoided energy and emissions costs, reducing the benefits of renewable generation.

Energy-related costs for LNG would still be subject to substantial fuel price volatility and thus significant hedge value. However, much of the cost of LNG delivered in Hawai'i is transportation cost, rather than strictly the fuel commodity cost, so the effect of fuel price volatility might be diluted somewhat.

On the other hand, LNG could also increase avoided capacity costs, which might boost the benefits of at least the baseload or dispatchable renewable generation sources. For now, it is unclear whether some LNG-fired generation capacity would be needed to meet incremental load, in which case some could be avoided, or if it would be needed only for reliability, ramping or ancillary services, in which case the avoided capacity value would still be minimal.

Questions Regarding Application of the Value of Renewable Energy Benefits

To date, the application of VOST programs, as well as traditional and two-part FIT programs, all use a flat $/kWh rate, which is either constant or escalating on a fixed schedule, determined in advance for a contract periods of 10-20 years. They are not time-varying tariffs. Variations in the timing and peak coincidence of the renewable technology, design (e.g., orientation or tracking) and siting are accounted for in the initial tariff definition and then held constant. Payment under these programs, as well as under PPA terms with large customers, depends only on the quantity of renewable generation.

The existing programs were designed for mainland utilities in large interconnected systems, with only a modest share of renewable generation. The situation is different in Hawai'i, with its small isolated systems, a different cost structure, and prospects for much higher renewable penetrations. These differences raise important questions regarding whether the VOST models applied on the mainland fit the Hawaiian context.

Since avoided costs and therefore the value of renewable energy benefits varies with time, should time-varying avoided cost values be reflected in time-varying tariffs for renewable generation? Ideally, this approach would be more accurate. Renewable project owners and developers generally have the modeling capability to forecast hourly performance confidently. Therefore, they should be able to adapt to a time-varying tariff, provided that the valuation is stable over their investment time horizon, and project future revenues with enough confidence to satisfy risk-averse investors.

Application of a time-varying tariff would require advanced metering. For non-dispatchable renewable sources like wind and solar photovoltaics, it is unclear whether a time-varying tariff would make much difference in the performance incentives from the perspective of renewable generation owners. Incentives that would influence system design (e.g., peak coincidence) could mostly be built into a constant tariff structure. Operational incentives would be much stronger for potentially dispatchable sources, such as biomass-fired generation or sources with integrated energy storage.

A different but related question is whether future adjustments to the value of renewable generation should be reflected in tariffs for renewable generation already in operation. Fuel costs change, increasing renewable penetration causes changes in the marginal generation source, and so on, so avoided costs and renewable benefit values can be expected to change over time.

In theory, adjusting the value of renewable generation would make the tariffs match the value of the product more precisely. In practice, however, future tariff adjustments, unless made according to a schedule that is transparent and known in advance, could increase the financial risk of renewable generation and handicap the prospects for renewable energy financing and development.