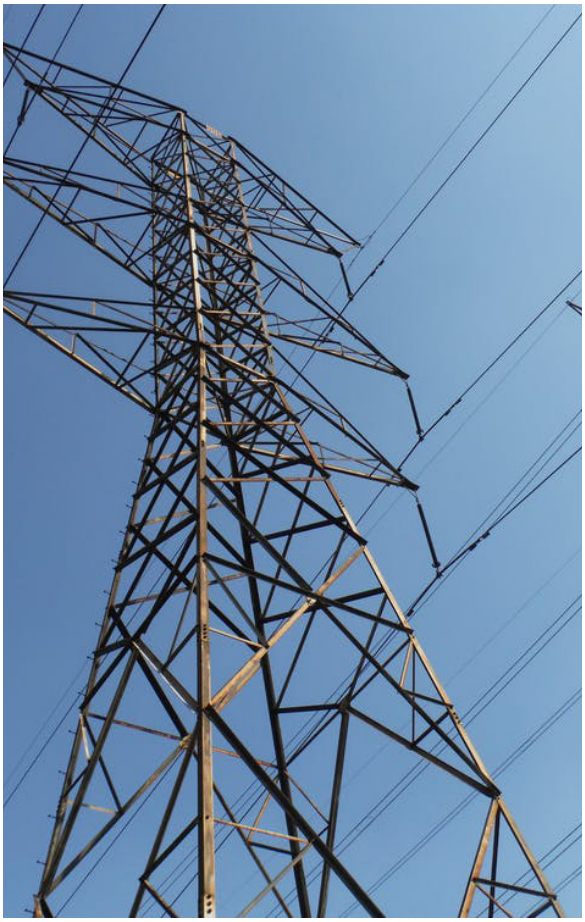

UNIVERSITY OF HAWAII ECONOMIC RESEARCH ORGANIZATION
THE UNIVERSITY OF HAWAII SEA GRANT COLLEGE PROGRAM

Governing Green Power Realigning Institutions To Fit New Technologies

NOVEMBER 14, 2017

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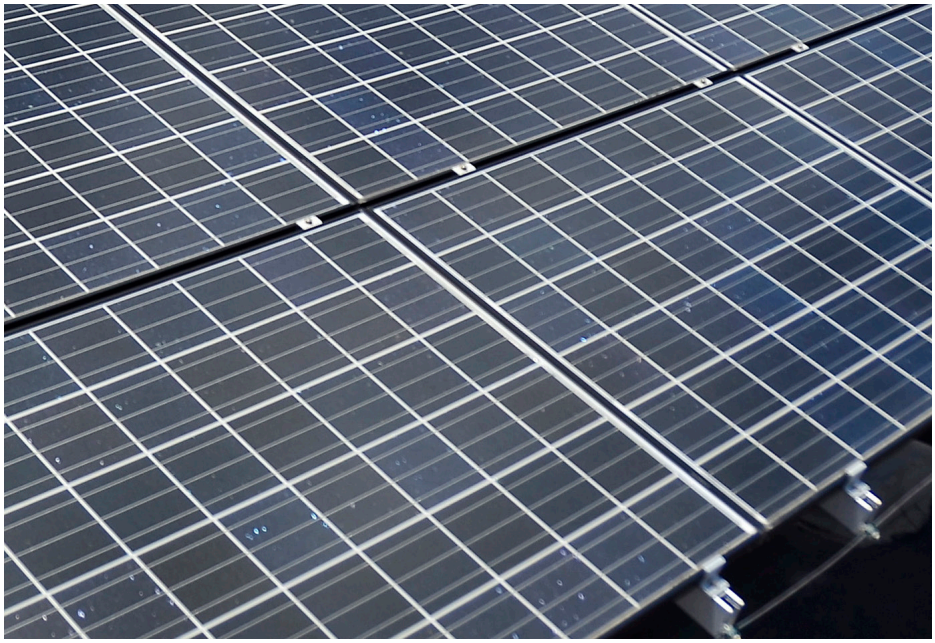

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Governing Green Power
Realigning Institutions To Fit New Technologies

A summary and elaboration of issues and ideas from a conference held in Honolulu, Hawai`i, March 28-30, 2017.

By Michael J. Roberts, Richard Pratt, Makena Coffman and Matthias Fripp

About the Conference and this Report

The "Governing Green Power" conference was held in Honolulu at the University of Hawai`i at Mānoa, March 28-30, 2017. The motivation for the conference was the recognition that energy technologies are changing faster than energy-related institutions — the organizational structures, market mechanisms, and regulatory incentives that govern power generation, transmission, distribution and storage. The complex system of the future that many of us envision — what some call Utility 2.0 — will require a carefully balanced infrastructure, dynamic price setting, and sophisticated automated control systems. How can this vision be achieved? How do the institutions that govern the electricity sector need to change to ensure that Utility 2.0 will be managed as fairly and efficiently as possible?

These were the broad questions that led to this conference. Hawai`i is a good place to discuss such cutting-edge issues because, with broad public and political support and the nation's most ambitious renewable energy portfolio standard, the state is on the leading edge of renewable energy. Moreover, the Islands' high cost of oil-based conventional generation likely make a substantial transition toward renewables economically feasible even in the absence of pollution externalities. The state is thus an important test bed for technologies and institutions needed to make renewable energy viable, fair and efficient. At the same time, for Hawai`'i's transition to be successful its work must be informed by developments in other places that are setting their own goals and wrestling with similar issues.

For this reason the conference included scholars, industry experts and stakeholders from Hawai`i, the U.S. mainland and abroad, bringing their diverse expertise, experience and perspective to the discussion. The conference agenda and attendees are listed in an appendix and can be found with a copy of this report at the conference website.

The conference was sponsored by a diverse collection of parties who shared its goals. These are, alphabetically:, Blue Planet Foundation, Carlsmith Ball, Collaborative Leaders Network, UH Mānoa College of Engineering, UH Mānoa College of Social Sciences, UH Mānoa Department of Economics, Hawaiian Electric Company, UH Mānoa Hawaii Energy Policy Forum, UH Mānoa Hawaii Natural Energy Institute, UH Sea Grant, the Sierra Club, UH Office of Sustainability, UH Economic Research

Organization, and Ulupono Initiative. Of course, the views recounted here are those of the authors and individual attendees, not the sponsors.

After brief introductions and motivating opening comments by Governor David Ige, the conference was structured around a series of pre-defined topics. We did not ask participants to present formal papers, but rather to make a brief panel presentation about what issues they saw as most critical relating to the integration of renewable energy. Conference calls and email correspondence before the conference allowed the panelists to coordinate their discussion. Each panel's presentations took about half the time allotted to frame and discuss the issue. The remaining time was dedicated to facilitated discussion among all participants. Attendees also shared several meals, all of which provided opportunities for intensive, substantive discussion around conference topics.

As expected, discussion in one session often overlapped with content in other sessions; it was difficult and unrealistic to make sharp demarcation. We aimed for an open and vibrant sharing of ideas, and it appeared that we were successful in that regard. (Results and comments of participants from an exit survey are provided in Appendix C of this report.)

The underlying issues can be complex, involving technical aspects of engineering, economics, law and the policy process. Some issues seemed well understood by most, while in some cases experts in different disciplines may have been talking past each other. On some points there seemed to be consensus, while others remain far from settled. A large presence of energy economists and engineers may have resulted in a little too much jargon unfamiliar to a wider audience. All attendees were leading experts in their respective areas, and at the same time, nearly all claimed to have learned a lot from the exchange, which is a gratifying start.

With the goal of continuing the conversations that are needed to improve the transition to renewables, this report summarizes and elaborates on a number of major issues that arose during the conference. It is *not* point by point reporting of the proceedings. Instead, we have attempted to provide context about the exchanges that took place and then to focus on distilling the major recurring themes of interest to many of the participants. We also offer some conclusions and recommendations which. while reflecting views of some participants, are ultimately the authors' and not a collective consensus position.

The themes we identify are: *Getting Prices Right*, *Inefficient Rate Designs*, *Grid Defection*, the *Importance of Aligning Incentives*, and *Managing the Transition to Utility 2.0*. Although these themes and the overall report reflect our views and opinions, we have attempted to incorporate alternative views to capture the range of discussion that took place at the meeting. In a number cases this goes beyond what was discussed directly during the conference in order to provide context for a broader audience and articulate the policy relevance of the discussions, for Hawai`i and other places. In some cases, differences in point of view are highlighted so that a wider audience can understand and appreciate them. We do not attribute names to specific views. Participants were promised we would not so they could feel comfortable speaking freely. The report is filled with links to other sources of information that readers are encouraged to follow for more background detail. The links are in lieu of references.

Contents

Executive Summary

Renewable energy technologies are changing fast. Today, despite remarkably low prices of oil, natural gas and coal, solar is now the most affordable source of electricity on a levelized-cost basis. And while affordable renewable energy has difficult challenges with variability and intermittency, rapidly falling battery costs and smart-grid systems can provide solutions to those challenges. The largest obstacles facing transitions to a clean, renewable energy future more likely pertain to the need to change institutions—the organizational structures, market mechanisms, and regulatory incentives that govern power generation, transmission, distribution and storage.

The conference themes, along with questions and points relating to them, are:

Getting Prices Right

Time-varying pricing and storage will become increasingly important as more intermittent renewable energy is integrated into the grid. Some questions this raises include: What would truly efficient pricing look like? How could it be achieved? What kinds of issues arise as prices become more variable? What kinds of pricing and contracting arrangements can be made with customers willing to embrace variable instead of fixed-rate pricing? How much does efficient variable pricing save relative to flat rates in a system with a lot of renewable energy?

Major Points

- *Efficient prices equal the marginal (or incremental) cost of electricity at each moment, at least for customers who are willing and able to have time-varying prices.*
- *Variable, marginal cost pricing would enable more flexible demand response technologies that would allow electricity loads to adjust with intermittent supply.*
- *Demand-side adjustments can also help in contingency events when a power plant falls offline, for regulating small variations from variable wind or clouds, or other disruptions.*
- *Some worried about the distributional consequences of variable marginal-cost pricing, while others emphasized the role of large-scale commercial customers that will likely see the value in potential cost savings.*
- *Marginal cost pricing will likely recover less revenue than needed to operate an efficient electricity system, or possibly enough for certain traditional base-load generators to remain in operation.*
- *While fixed charges at the retail level and capacity markets at the wholesale level can help to reconcile revenue shortfalls, there are many unresolved questions about how to allocate fixed charges and how to clear capacity markets in a manner that treats all customers and supply sources fairly.*

- *A new, multi-resource capacity auction mechanism was suggested that would collect bids from generation, transmission and demand-response providers to clear a least-cost planning model encompassing timescales from minutes to decades.*
- *In a high-penetration renewable system, the value of flexible pricing arrangements could be worth at least three to four times as much as a fossil system, and even could make a 100% renewable system more cost effective than a fossil system by 2045.*

Inefficient Rate Designs

Current rate structures can cause unintended consequences that may work against efficient integration of renewable energy. What are some of the most problematic rate structures? How do these influence efficiency as well as fairness? How could goals of these problematic rate designs be achieved in more effective manner?

Major Points

- *Commercial and industrial customers often pay a demand charge that scales with their peak load. Since peak loads differ across customers, and peaks may become less costly if aligned with times of plentiful renewable energy, these charges will become increasingly misaligned with system costs.*
- *Net-metering agreements, which typically allow customers with solar PV to buy and sell from the utility at the same price, do not account for the time-varying value of electricity. And because fixed costs tend to be folded into volumetric rates, net metering implicitly redirects some costs to other customers.*
- *Feed-in tariffs typically pay fixed, above-market prices to early renewable energy producers, prices that exceed the incremental cost of power in the system, and far exceed the incremental cost of renewables, which is essentially zero.*
- *Block pricing, which charges customers a higher volumetric price depending on the amount of electricity used each month, can distort incentives for distributed generation. Equity motives for block pricing might be achieved more effectively and efficiently through other means, like means-tested energy assistance.*

Grid Defection

As solar photovoltaic, batteries, and small-scale generators become increasingly cost effective, and grid management costs rise, some electricity customers may find it economical to produce more energy themselves or disconnect from the grid altogether. As demand for electricity from the central utility falls, grid infrastructure and management costs must be spread over a shrinking load, raising average prices, potentially causing more grid defection. Under what circumstances would grid defection actually make economic sense? How might pricing policies cause more grid defection than socially desirable? What kinds of pricing policies would deter inefficient grid defection? Is mass grid defection plausible?

Major Points

- *While many remain skeptical that large-scale exit from the traditional grid will be desirable for most customers, the pace of cost declines for solar PV and batteries has far exceeded expectations, and these declines are likely to continue as volume grows. Grid defection could be more likely that some believe*
- *A key concern is "inefficient bypass," which refers to customers who bypass the grid even when the incremental cost of keeping them connected is less than the price such customers would be willing to pay.*
- *If some customers leave the grid, efficiently or not, fixed costs of the grid infrastructure would need to be covered by fewer and fewer customers, possibly leading to more defection.*
- *Efficient marginal-cost pricing combined with fixed charges and exit fees to cover sunk grid costs could resolve inefficient grid defection, but may be politically untenable.*

Aligning Incentives

Currently, regulated utilities are allowed to set prices in order to collect revenue to cover approved operating expenses and a "fair rate of return" on capital investments. In many cases, regulated utilities have little incentive to control costs. The more distributed nature of the future utility is putting greater stress on the traditional regulatory model. How should incentive structures change so that the utility of the future will be motivated to manage the grid in cost effective way?

Major Points

- *Utility regulation has always struggled with an inherent tension between keeping prices low while providing utilities an incentive to control costs appropriately.*
- *Cost-of-service regulation may work adequately when the utility has little private information about its cost of operations and the scope for innovation is limited.*
- *Given uncertainty about continuing, rapid technological advance, it is objectively unclear what kind of grid enhancements are needed, and we should expect the regulated utilities to come down on the side that maximizes their own investment while minimizing that of competing interests and resources.*
- *Many suggested a turn toward holistic, customer-oriented, performance-based incentives, while others expressed concern that poorly designed incentive structures could lead to windfall gains to the utility that could be difficult to reverse.*

Managing the Transition to Utility 2.0

Who gains and who loses from the transition toward renewable energy and a modernized grid that can manage it effectively? What are the political and economic

obstacles to this transition? What kind of process can best manage and resolve tensions between the various interests and stakeholders?

Major Points

- *The transitions from fossil fuels toward renewable energy are both technically and institutionally complex. Such transitions require wrestling with difficult choices in a way that employs solid analytics in a transparent and public regarding way.*
- *Complex transitions can be managed with a range of policy mechanisms, ranging from "top down" approaches such as mandates to "bottom up" approaches that may emphasize performance-based incentives.*
- *While much of the policy emphasis has focused on renewable energy goals, more attention needs to be directed toward implementation of those goals.*
- *There are roles for both experimentalism (trying out new policy tools to see how well they work) and incrementalism, no-regret steps that move things forward.*
- *Successful transition requires adaptive institutional with strong leadership that is willing to be pro-active instead of reactive.*
- *Successful transitions require constructive stakeholder and community engagement that clearly defines the issues, develops the right forums for discussion at the right time, and skillfully facilitates productive interaction.*

Introduction

Renewable energy technologies are changing fast. Over the last 7 years, between 2009 and 2016, the wholesale **levelized cost**[1] of wind power has fallen from a global average of about $13.5 cents per kWh to about $4.7 cents per kWh, a decline of two thirds. The unsubsidized wholesale cost of utility-scale photovoltaic solar has fallen from 35.9 cents per kWh to approximately 5.5 cents per kWh, a decline of 85 percent. In much of the world, the levelized costs of solar and wind are now roughly comparable to those of natural gas and coal, currently the least expensive fossil fuels. With anticipated future technological advance, these clean energy sources will soon be far less costly on a levelized basis than the cheapest fossil fuels.

Last year (2016) in the United States a majority of new generation capacity was wind or solar, and nearly 90 percent of new capacity in Europe was renewable. At the same time, coal use is declining in much of the developed world and globally. Even in China, coal use may have peaked in 2013. These developments, plus improvements in energy efficiency have caused greenhouse gas emissions to stabilize over the last few years, despite substantial world economic growth.

While these technological developments are encouraging, wind and solar energy also are quite unlike traditional sources of electricity: they are intermittent and not easily controllable like traditional fossil fuel plants. For these technologies to be viable at a large scale requires some combination of energy storage, improved transmission from times and places of high supply to times and places of greatest demand, and to the extent it is both feasible and cost effective, shifting of demand from times of greatest convenience to times of greatest energy supply.

Battery technologies, which also are advancing rapidly, may help to fulfill the role of storage. There are, however, ways to store energy more cost effectively than using batteries, many of which exist as co-products to standard uses of electricity. These include thermal storage in water heating, refrigeration and air conditioning systems. Some uses of electricity, like water pumping or charging of electric vehicles, might be scheduled at little cost or inconvenience to times most suitable for intermittent renewables.

Technologists imagine a future where all manner of building control systems and household appliances are managed by smart controllers connected through the internet or other means to an integrated power system, facilitating efficiency, convenience and a generally more flexible integrated power system. Engineers have only just begun to imagine what is possible in existing systems, for until recently there has been little use of load shifting technologies, much less the incentives to conceive of them.

The envisioned Utility 2.0 would be far more complex than the current one, with many time-varying and geographically distributed sources of supply, demand, and storage. Perhaps most critically, electricity would become increasingly multilateral, flowing into and out of homes and businesses and a wide array of storage devices, appliances and mechanisms. To control-room engineers, the thought of orchestrating a dizzying array of distributed resources amid great variability and uncertainty may seem

[1] A glossary is provided for words in boldface.

fanciful. Economists, on the other hand, may offer that such complexity exists for all manner of commodities, all neatly organized by prices. To efficiently coordinate a complex array of power system activities simply requires real-time markets and variable pricing. Fast, cheap computing technology and network connectivity should help. In an age of high frequency financial and commodity market trading that operates on millisecond time-scales, surely such a system is possible.

The challenge is that electricity cannot be produced and exchanged in an unfettered market, but requires a carefully regulated one. Trade takes place over a grid of wires and transformers, many parts of which are a natural monopoly, especially at the distribution level. Some transmission and power generating companies have market power too, especially near capacity limits. And the system needs centralized control, even if automated, to keep supply and demand in perfect, continuous balance. Thus, where the vision of Utility 2.0 is essentially one of a decentralized, perfectly competitive market, that vision conflicts with the centralized nature of a conventional utility. The conference focused on issues and challenges that surround the technical implementation of this vision. It also considered whether conventional regulated utilities are provided an incentive to effectively manage the transition, or whether these incentives need to change.

Getting Prices Right

Time-varying pricing and storage will become increasingly important as more intermittent renewable energy is integrated into the grid. Some questions this section considers include: What would truly efficient pricing look like? How could it be achieved? What kinds of issues arise as prices become more variable? What kinds of pricing and contracting arrangements can be made with customers willing to embrace variable instead of fixed-rate pricing? How much does efficient variable pricing save relative to flat rates in a system with a lot of renewable energy?

Major Points

- ***Efficient prices equal the marginal (incremental) cost of electricity at each moment, at least for customers who are willing and able to have time-varying prices.***
- ***Variable, marginal cost pricing would enable more flexible demand response technologies that would allow electricity loads to adjust with intermittent supply.***
- ***Demand-side adjustments can also help in contingency events when a power plant falls offline, for regulating small variations from variable wind or clouds, or other disruptions.***
- ***Some worry about the distributional consequences of variable marginal-cost pricing, while others emphasized the role of large-scale commercial customers that will likely see the value in potential cost savings.***
- ***Marginal cost pricing will likely recover less revenue than needed to operate an efficient electricity system, or possibly enough for certain traditional base-load generators to remain in operation.***
- ***While fixed charges at the retail level and capacity markets at the wholesale level can help to reconcile revenue shortfalls, there are many unresolved questions about how to allocate fixed charges and how to clear capacity markets in a manner that treats all customers and supply sources fairly.***
- ***A new, multi-resource capacity auction mechanism was suggested that would collect bids from generation, transmission and demand-response providers to clear a least-cost planning model encompassing timescales from minutes to decades.***
- ***In a high-penetration renewable system, the value of flexible pricing arrangements could be worth at least three to four times as much as a fossil system, and by 2045 could even make a 100% renewable system more cost effective than a fossil system.***

We began the conference by asking each participant to say, in just a sentence or two, what they saw as the most important issue or question surrounding renewable energy integration. By far the most prevalent answer related to getting prices right. The basic

idea is that retail prices ought to reflect the true cost of providing electricity at different times and places, a cost that will become more variable with intermittent renewables. This predominant view may have had something to do with the large number of economists in the room, but some trained as engineers or policy professionals shared it. Discussion throughout the first day returned to pricing in a number of ways, so much so that we explicitly pushed discussion away from it on the second day. There seemed to be broad consensus that getting prices right was key, and a lot of the subsequent discussion revolved around the details of what correct price setting would look like in practice, how it would be implemented, and who would gain and who would lose with such pricing.

Efficient pricing has a specific technical meaning: the price of electricity should equal its **marginal cost**, or the *incremental cost* of providing one more kilowatt at each moment in each place.[2] Marginal cost will often be far greater or less than the average cost of electricity. For example, in parts of the U.S. and Europe, including Hawai`i, that have a lot of renewable energy, there are times when excess renewable power must be curtailed (discarded). Curtailment occurs when it is not cost effective to further reduce generation from other power plants. During such times, the marginal cost of electricity is zero, or possibly even negative,[3] while retail customers are almost universally charged a positive price. Times like this are inefficient because customers buying electricity are presumably willing to pay positive price for a little more electricity while it would be costless to provide it for them. Sometimes this gap between marginal cost and price can be substantial, exacerbated not only by average cost pricing but also current contracting practices. At this writing, over 10 percent of wind generation on the island of Maui is typically curtailed while residential customers simultaneously pay about 34 cents per kWh.

Conversely, during critical peaks, when demand for electricity nears capacity limits of generation or transmission, the marginal cost of electricity can be very high. Satisfying peak demand requires use of expensive peaking power plants that have a high variable cost and must recover their capital cost over a small number of peak hours, resulting in a high capital cost per hour. At these times, customers typically pay a price far less than marginal cost. This kind of pricing inefficiency has always been prevalent in conventional electricity systems, and critical peak pricing can go a long ways toward resolving it.

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[2] Some make a distinction between short-run marginal cost and long-run marginal cost. In the short run, new generation equipment cannot be installed, and there will be a physical limit on the capacity of the system, such that the incremental cost becomes infinite once that limit is reached. In the long run, marginal cost includes the incremental cost of expanding capacity. Peak times would not have an infinite price, but rather a price that is high enough to limit quantity demanded at the constrained point in time, a price that, for an efficient system, would also equal long-run marginal cost. Short-run and long-run marginal costs only differ at these system-constrained times. Things also change somewhat as storage becomes more prevalent. See footnote 4.

[3] Marginal cost could be negative if subsidies are tied to successful sale and delivery of power, which is often the case. Marginal cost could also be negative if it is cheaper to keep conventional plants running that to turn them off for short periods.

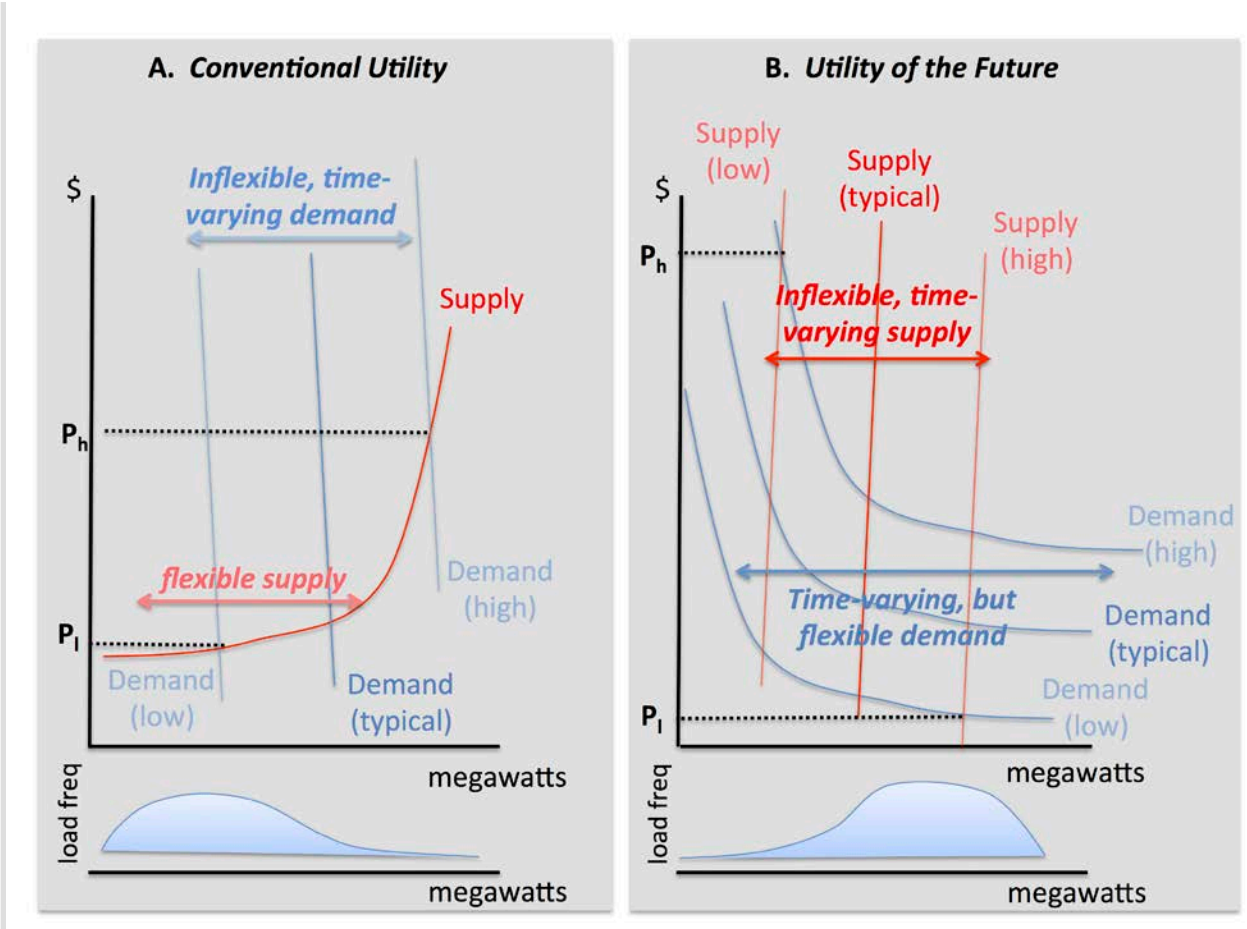

Figure 1. *Intermittent renewables change the nature of the utility. The horizontal axis is power generated or consumed at a point in time, and the vertical axis is incremental willingness to pay (Demand) or marginal cost of generation (Supply). A typical frequency distribution of load is shown at the bottom. Panel A shows a conventional utility with flexible (flat) supply that can ramp generation up and down with varying demand without greatly changing the incremental cost of power, except for rare peaking loads, so efficient prices are typically low (P_l). Welfare gains have been gleaned from curbing peak loads with critical-peak pricing and demand charges for commercial users, which tie each firm's incremental price to its historical peak. Panel B shows a hypothetical utility of the future, with generation coming mainly from inflexible (steep), time-varying intermittent renewables and real-time pricing. With highly volatile time-varying prices, storage and shiftable loads cause demand to become more flexible, especially in the lower price range, but prices can spike very high during unusual periods when supply is low and demand high.*

In a future with a large amount of intermittent renewable energy and storage, marginal cost will be more variable, and will depend not just on variable weather-dependent generation and demand, but also on the amount of stored energy and anticipated demand going forward (Figure 1). In the absence of a competitive market, simply calculating an appropriate marginal cost could be more challenging.[4]

[4] In a system with storage, marginal cost will include a resource rent that reflects the overall scarcity of electricity in the system. As with commodity markets, prices will rise as the inventory of stored energy declines, or if speculative events (e.g., an impending heat wave or energy drought), makes current stores more precious. Williams and Wright provide a comprehensive treatment of storage and pricing, but there

Demand Response

Marginal cost pricing, or something close, exists in regions where **wholesale markets** exist and are competitive. In these regions, the challenge is bringing wholesale prices to the retail level, thereby enabling advanced technologies that would facilitate distributed storage and demand-side adjustments to help keep the grid in continuous balance in the face of more variable renewable supply. The crux of enabling Utility 2.0 is thus demand response.

At the risk of over-generalizing, economists and engineers tend to have different ideas about demand response, differences that sometimes obscure communication between these professions and can give rise to different ideas about policy. These differences elicited a vibrant discussion about the way demand response ought to work in practice.

To economists, "demand response" usually refers to the amount customers will change electricity use as price changes (the path along one of the blue curves in Figure 1): raise the price, and quantity demanded will fall, holding all else the same. To engineers, "demand response" is a resource —a knob in the utility control room—that can be used to shut off power for certain customers during a contingency event (for example, a power plant suddenly falls offline). In practice, this would balance the system much like ramping up a conventional power plant. Views surely vary among economists, engineers and other practitioners, but this demarcation roughly aligns with these two disciplines. And, as we try to make clear, both viewpoints are critical to development of "smart" demand response mechanisms that can efficiently integrate with renewable energy.

In one sense these different ideas about demand response amount to the same thing: ways of adjusting electricity demand to follow supply rather than the usual method of adjusting supply to follow demand. But there are important differences that connect to different policy instruments. Economists imagine real-time varying prices and customers with automated devices set to adjust electricity use depending on price and their current situation. Engineers may be thinking about fixed-price contracts that have been signed in advance with customers that give the control room authority to adjust their use remotely under certain circumstances. Many customers in Hawai`i, for example, agree to let the utility remotely turn off their water heaters for a short time in exchange for a small discount on their monthly bill. Usually these contracts involve commercial or industrial businesses with significant demand.

One difference between the economist's view and the engineering view concerns the control mechanism. Economists like the idea of using prices to elicit the desired response rather that directly controlling it. Engineers, on the other hand, know that power systems need to maintain a precise balance between supply and demand, and justifiably question whether price adjustments can elicit a precise load response. System management does require a knob in the control room.

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has been no application to electricity markets about which we are aware. In time, electricity pricing may begin to look more and more like standard commodity pricing.

Another difference concerns the nature of the contract between the utility and the customer. Economists prefer prices because they allow any willing party to respond, which should generally lead to a more efficient and flexible outcome. It would also elicit clear incentives for innovation that could create value from buying at low prices and selling at high prices. Fixed-price contracts can be inflexible by comparison. The value of demand response services will change over time and circumstances. Many demand-response mechanisms, if they exist, do not reflect that changing value. Furthermore, contracting firms may have their own contingencies, and thus may be unwilling to sign onto a rigid contract. There may also be significant transaction costs involved with negotiating individual contracts. Finally, concern was expressed about compensating customers for reducing demand from baselines based on previous behavior, because the baselines might be manipulated to fraudulently boost demand-response payments. Other, more subtle issues can also arise when demand response payments are connected to baselines.

A third difference concerns the nature of what is being exchanged, energy or grid services. Real-time pricing presumes a market for electricity itself, while contracting for demand reduction under special circumstances is a form of grid service that helps the control room maintain balance in the system. In wholesale markets, these concepts can merge when both energy and reserves are traded in simultaneous day-ahead and real-time markets. The examples above describe a form of **up reserves**: the demand-side equivalent of *ramping up* generating units to meet a contingency event in which more power is needed. **Down reserves** provide the opposite service: quickly increasing demand or *ramping down* generating units in a contingency event when less power is needed. The value of reserves depends on the amount, speed and duration of the response, as well as the frequency and timing of events for which the service is used.

Conventional demand response programs usually involve a fixed-price or individual contracting model, like the Hawai'i water heater example above. It is technically feasible, however, for water heaters to provide a more robust set of demand-response services. If a water heater were designed to forecast prices and respond to them, it could super heat when renewable energy was plentiful and prices were low, and could simultaneously provide up reserves over short durations to handle passing of clouds or variable winds. Since residential customers less frequently use hot water in the middle of the day, customers armed with the right technology could provide these kinds of services for very little cost in capital or inconvenience. But we need clear price signals—for both reserves and electricity itself—to incent appliance manufacturers to build such water heaters and other kinds of smart appliances, and for customers to buy them.

In Hawai`i, the Public Utilities Commission has been pushing Hawaiian Electric Company (HECO) to develop a more robust demand response program. At the conference a representative from HECO described how it was developing a menu of pricing contracts for different kinds of demand response. These include various frequencies and durations of reserve services they could provide, as well as general load shifting that is more consistent with economist' notions of demand response for energy. The HECO representative described how the different services might be bundled together, possibly by third-party integrators.

HECO's planned approach captures some benefits of both real-time pricing and contracting. It wasn't clear, however, how pricing of demand-response services under its program might change over time as renewables, storage and other components of the overall system evolve. Seasonal and weather-related circumstances would also change the value of such services over short periods of time. It seems unlikely that the regulatory process could respond quickly enough to changes in events and distributed infrastructure. To inspire innovation, it would be important for third parties to anticipate how demand-response pricing would evolve over time.

In regions with wholesale markets, FERC rule 745 allows demand response integrators to sell services, both energy and reserves, into wholesale markets on equal footing with power generating companies. Generating companies attempted to challenge the rule, but ultimately it was upheld in a recent Supreme Court ruling. At least for the mainland U.S., this ruling should open a door to competitive demand-response programs that can evolve with the grid. Challenges remain, however, in merging transmission-level markets with distribution-level demand response.

One attendee, a consultant with a lot of experience in market development, presented a strategy for the United Kingdom in which customers would select devices for different kinds of demand responses using color-coded devices on outlets. Each color would represent different level and kind of flexibility (e.g., tolerance for interruption). An aggregator would write contracts with households and have control over the devices, and then sell aggregated grid services into the wholesale market.

We are just beginning to see development of new demand response systems. More should be expected in the near future. Making demand response better-suited to renewable energy integration will require mechanisms that combine evolving, time-varying value of both energy and reserves, as well as automation that facilitates precise, control-room predictability of response.

Real-Time Pricing Without a Market

Discussion at the conference oscillated between Hawai`i-specific issues and issues relevant to other locations and institutional situations (e.g., with wholesale markets). One issue particularly relevant to Hawai`i, and alluded to above, concerns how to appropriately set time-varying rates in regions that lack a wholesale market.

A few integrated utilities have had success with real-time pricing. Georgia Power was an example brought up multiple times during the conference. It makes real-time pricing contracts available as an option to all commercial and industrial users, an option that a majority of commercial customers have adopted. Interestingly, Georgia Power is a vertically integrated utility, much like Hawai`i's, that does not have a wholesale market. But there is much less experience with real-time retail pricing of both energy and reserves, or for residential or smaller commercial customers. And where real-time retail prices do exist, prices do not vary as much as they probably would in a power system with a substantial amount of wind and solar.

One solution is to simply create wholesale markets where there are none. While some question whether the market is sufficiently large in places like Hawai`i to have competition, there are successful examples of competitive wholesale markets on relatively small island economies. Ireland and Crete were specifically mentioned, and

there may be others. On O`ahu, Hawai`i's most populous island with about one million people, just two independent power plants, Kalealoa and AES, generate almost half the island's electricity. AES, the state's only coal-fired power plant, has average generation costs far below any of the other power sources. If AES were to receive competitive (i.e., marginal cost) prices for its power it would earn extraordinary excess profits. However, multiple participants with experience in market development argued that carefully constructed contracts could be written that would limit the market power and excess profits of such facilities. (See discussion of capacity markets below.)

Another option, suggested during the conference, is to simply offer rates with hourly marginal cost pricing tied the **system lambda**, which is a measure of marginal cost that comes directly from the control room software of the balancing authority. Each balancing authority that manages a system of at least 200 MW is required to report demand and the system lambda each hour (see FERC form 714 data). The Public Utilities Commission could also require utilities to report this value on an hourly or sub-hourly basis. Such a pricing mechanism would be relatively easy to implement, could be made optional for customers, and may begin to shape demand in a manner more amenable to growing renewable penetration. Large-scale commercial and industrial customers, at least some of which already have 15-minute **interval meters**, would be the most likely to participate. When someone asked why Hawai`i had never considered such a simple mechanism, someone familiar with deliberations at the PUC answered that it simply had not been proposed by one of the stakeholders.

An earlier policy brief, authored by several members of the conference's organizing committee, argued that, for fairness and efficiency, rates ought to be tied in one way or another to marginal cost. It is summarized here because it seems to align with the generally held sentiment (at least among economists) at the conference about "getting prices right." The brief describes three simple rate designs that would be amenable to different kinds of customers with different kinds of meters and willingness to bear risk and variability. These rates were:

1. Marginal-cost pricing calibrated to the real-time system lambda every hour depending on customer choice and/or technical feasibility. This would require appropriate metering, which often exists for large-scale customers.

2. Time-of-use pricing, updated monthly, that is tied to the previous month's load-weighted marginal cost for the customer class for each of a series of key time periods (e.g., night, morning peak, mid-morning off-peak, afternoon, evening peak). This tariff would require **interval meters**, but not necessarily **smart meters**, and are fairly inexpensive.

3. A flat per-kWh rate, updated monthly, that is tied to an estimated load-weighted marginal cost for the customer class in the previous month or forecast for the current month. This tariff would not require a special meter.

Since the pattern of marginal costs is likely to change over time, it will be important for rates to evolve in a manner that is consistent with those changes, and in a way that customers and innovators can begin to anticipate and adjust to. At the same time, some

customers may be unable or unwilling to pay attention to prices in real time and would not want to be subject to surprises. The second and third options would provide more predictable and gradual changes over time. These kinds of rate structures would enhance efficiency, reduce overall system costs, and evolve appropriately over time with changes in renewable penetration, storage costs and other factors. These rates also should be easy to implement today for most utilities. They would not account for demand response in the form of contingency reserves, but also would not prevent such contracts.

These rates also could be used to solve many of the problems with net metering for solar customers. (More on net metering below.) If distributed generation fed back into the grid were compensated in real time at the marginal cost of generation, it would provide appropriate compensation to distributed solar installers while simultaneously providing incentives for efficient load shifting and energy storage.

During the conference there did not seem to be a clear counterpoint to the view that tariffs ought to be based on marginal cost pricing, although some concern was expressed about how the benefits of variable pricing would be distributed among different kinds of customers. While the system as whole would benefit, and those with especially flexible demand would presumably benefit more than customers with inflexible demand, it's not clear why any particular group of customers would be harmed by marginal cost pricing. If certain customers happened to demand electricity most during times that were hardest to serve (e.g., the evening peak) and had the highest marginal cost, then those customers might be hurt by marginal cost pricing. Some may argue that such customers ought to pay more because they would be buying a more expensive product, and charging them less amounts to an implicit subsidy. Even these customers might benefit from marginal cost pricing because the system-wide reduction in overall costs may compensate for the relatively high average prices of certain demand profiles.

Another way to deal with perceived inequities is through allocation of fixed charges. If, for example, commercial and industrial customers gain from marginal cost pricing, because their nominal loads are higher during low-cost midday times with a lot of inexpensive solar, and residential customers lose because their nominal loads are heaviest during more expensive evening loads, fixed charges could be increased for commercial and industrial users and reduced for residential customers. So long as fixed charges do not cause customers to terminate service (i.e., grid defection), efficiency considerations are unaffected by allocation of fixed charges.

Transmission and Inter-regional challenges

Hawai`i, unlike many developed areas, is self-contained vertically-integrated utility. Other parts of the country and world have wholesale markets that manage generation and transmission, with utilities mainly managing distribution. And while some mainland regions also have vertically integrated utilities, most also are connected to other regions and can buy and sell power from them. Connectivity also creates a great deal of inertia and associated stability in the system. Hawai`i's, islands, in contrast, are not connected to each other, much less to the mainland, have limited inertia, and no ability to trade between islands or inter-regionally. While Hawaii's geography and public utility present

many unique challenges, governance issues that require coordination between states and regions—especially long-distance transmission—are not a concern.

Wholesale markets, where they exist, navigate an increasingly difficult challenge of ensuring sufficient capacity and an efficient mix of generation, storage and transmission. Even before intermittent renewables came onto the scene, power markets were still evolving and controversial. Because retail prices are regulated and cannot normally respond to short-term changes in wholesale prices, demand for power from wholesale markets tends to be unresponsive to price changes, and can therefore be especially susceptible to market manipulation during times and in places where generation or transmission near capacity limits.

Today, a combination of factors, including growth of intermittent renewable wind and solar energy, are causing wholesale prices to fall and become more variable, challenging profit models of traditional base-load power plants, especially coal and nuclear. Natural gas, following a deluge of supply from hydraulic fracturing (or fracking), is a cleaner, cheaper, and more flexible fuel than coal and nuclear. Power plants of varying sizes can be built to burn natural gas and can be easily ramped up or down, thereby providing a good complement to renewables. While natural gas still emits carbon dioxide, a key greenhouse gas, emissions (mainly nitric and sulfur dioxides) are about half those of coal, and other pollutants are virtually eliminated relative to other fossil fuels. Perhaps the greatest pollution concern with natural gas comes from methane leaks deriving from fracking sites and imperfectly sealed pipes. Methane is a greenhouse gas with roughly 50 times the warming potency of carbon dioxide, so even small leaks could greatly reduce its environmental advantages over other fossil fuels.[5]

A key challenge on the mainland United States, in Europe, and for most larger continental regions, involves optimizing transmission to efficiently spread renewable energy from places and time of greatest supply to place and time of greatest demand. Recent research suggests that great efficiency gains are technically possible by connecting regions using long-distance, high-voltage transmission lines. Such gains require difficult coordination and planning across larger geopolitical areas. FERC order 1000, which set out rules for allocating cross-state transmission lines, was designed to streamline this process for the United States. Some comments during the conference suggested this rule could be improved. While there seems to be movement in the direction of greater inter-regional integration, it's not clear whether incentives exist to facilitate an efficient evolution of generation, transmission, storage and demand response.

In time, better transmission, storage and demand response could act to smooth out variability even as renewable energy grows. In the near term, however, some are concerned that wholesale markets are not covering capital costs of base-load power plants, an issue we turn to next.

Missing Money?

[5] Other potential concerns with natural gas and associated fracking are groundwater and surface water pollution and micro earthquakes. See, for example, this article.

While many energy experts, and especially economists, can get behind the idea of marginal cost pricing, it's unlikely that revenue collected from marginal cost pricing will equal the total cost of the electricity system. Marginal cost pricing could collect more or less revenue than the total cost of power, transmission and distribution. If the marginal price tends to be above the average generation cost, then surplus revenues will be generated to cover fixed costs and possibly generate excess profit; if marginal price tends to be less than average generation cost (there are economies of scale), then too little revenue will be collected, and there will be a so-called "missing money" problem.

Even if marginal cost typically exceeds average cost for the system as a whole, it may not for individual power plants. Solar and wind, for example, have large fixed costs and zero fuel costs. And because wind and solar are often subsidized, the breakeven marginal price for these sources can be negative. That is, providers may be willing to pay a utility to take their power, if the payment is less than the explicit or implicit subsidy obtained for delivering that power. In a marginal-cost pricing system, these generation sources make money to cover fixed costs when other, more costly generating sources serve marginal loads—that is, anything above zero.

Even within the narrower domain of wholesale power markets, low and sometimes negative real-time prices (when zero marginal cost renewables are especially plentiful) are putting financial pressure on traditional base-load power plants (mainly coal and nuclear) that have historically operated at full capacity and cannot be easily ramped up and down. These power plants incur losses by burning fuel that can be more expensive than the price they receive, but it can be even more costly for them to temporarily shut down and restart when prices rise again. They also have high fixed costs of capital. As a result, coal and nuclear power plants are being squeezed and have begun to exit the sector. Natural gas power plants are smaller, can be more easily ramped up and down, have historically low fuel costs that are now cost competitive with coal and nuclear, and are thus a better complement with renewables.

It's not clear whether a broader **missing money** problem exists—that the closing of traditional base load power plants is a fundamental concern. It's possible that coal and nuclear power plants simply cannot compete against increasingly competitive renewables and natural gas. There is concern, however, that as power plants fall offline, there will be insufficient capacity to satisfy peak loads. Or, perhaps more subtly, that if generating capacity gets too tight, it will exacerbate market power of generating facilities in constrained times and areas. Many are also concerned that the loss of large nuclear power plants could jeopardize reductions in greenhouse gas emissions. At least in places with real-time wholesale power markets, a carbon tax could go a long way toward reconciling this problem, helping nuclear stay viable for longer while pushing old coal offline.

Capacity Markets

To alleviate concerns about missing money and other issues, there has been an outgrowth of **capacity markets** in many areas with real-time wholesale markets. These markets can resolve the missing money problem, ensure enough capacity to limit market power around peak loads, or maybe even extract surplus revenue if marginal cost pricing brings more revenue to certain power plants than needed to cover costs.

Questions about the right price for capacity therefore dovetail with questions about getting prices right for electricity in general.

There was some debate, however, about whether capacity markets are truly necessary, whether they implicitly favor traditional fossil fuel power plants, as well as the nature and structure of capacity markets if deemed necessary. Some argue that "energy only" markets should be sufficient, with some power plants deriving necessary revenue from rare peak pricing events. Others argued that energy-only markets were too vulnerable to extreme price spikes, which complicated financing and stability of the system, and that capacity markets resolved this problem efficiently.

When markets are used to ensure a given level of capacity, some argued that it was important to account for different kinds of generation capacity in a more flexible way. Not all generation capacity is the same, since some kinds of generation are more flexible (more easily ramped up and down) than others. Solar and wind may not be able to guarantee any degree of capacity, due to their intermittency. The crux therefore comes down to how capacity is defined in these markets, and an argument was made at the conference that, in practice, this definition tends to favor fossil fuel plants over renewables, mainly because renewable energy capacities cannot be committed too far in advance and therefore cannot participate in such markets.

The definition of capacity creates a certain amount of arbitrariness in the way these markets operate, for capacity itself needs to valued relative to the whole portfolio of generation, storage and transmission assets in the system. For example, a modest amount of solar power in a system that tends to peak in the middle of sunny days, will have extremely high value. Additional solar power in a system that already has lot of it and peaks after the sun goes down will have much less value. Similarly, power plants with different ramping ability, minimum operating capacity, and fast versus slow startup times will have values that depend on the rest of the generation, transmission and storage infrastructure. Since not all capacity is alike, how can a capacity market be structured to deliver an efficient portfolio, while allowing different kinds of system investments to compete fairly against one another?

One possibility is to have all proposed investments for new generation and transmission facilities (perhaps including demand response) bid into an agreed upon modeling platform that accounts for the whole portfolio of generation, transmission and storage assets. Such a model would need to consider each facility's capacity, generation profile and constraints, projected chronological load sequences over a long planning horizon, potential for demand response, reserve requirements, as well as pollution emission factors to meet renewable portfolio standards or other regulations. If selected as part of the system, a proposed investment would receive the system-wide marginal cost of generation when delivered, plus its offered capital price.[6] The model could then select the offered projects that minimize the present value of overall cost subject to meeting projected loads and other requirements.

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[6] In a competitive capacity market of this kind, offers for proposed investments might be negative, if marginal cost pricing would yield significantly more revenue than cost. Thus, a well-structured investment market can solve both missing money and surplus money problems. Transmission and storage could also be part of the market.

One of the co-organizers for this event developed the first model of this kind, SWITCH, which is discussed further below. Other similar models are in development, and one, developed by E3, was used to aid development of HECO's recent Power Supply and Improvement Plan. We do not believe such a market has ever been proposed, much less implemented. Nor do we know of any markets that have considered generation, storage and transmission offers simultaneously. A similar mechanism could be used by a centralized authority (a municipality, integrated utility or cooperative) to purchase independent power and transmission via an inclusive, multi-resource reverse auction. These ideas, shared at the conference, deserve more careful consideration.

The Potential Value of Getting Prices Right

How much could be saved if we actually got prices right? Research has investigated this question, but it has been directed mainly toward conventional systems with little renewable energy. These studies show that relatively modest efficiency gains can be gleaned, mainly from better pricing of critical peaks.

While estimated gains from variable marginal-cost pricing in conventional systems are modest, there may be more benefits than implied by the modeling exercises linked above. First, marginal cost retail pricing can help to reduce manipulation of wholesale markets when nominal demand nears capacity limits. If retail prices spike when wholesale markets do, then customer reductions in electricity use make it much more difficult for a marginal power plant to profit from unscrupulously cutting back supply, behavior that caused a crisis in California. Real-time retail pricing and demand response will not prevent efforts to manipulate power markets, but it can help.

A second auxiliary benefit, one that is difficult to measure, involves induced innovation. Availability of real-time retail pricing (especially if it allows selling as well as buying of electricity at a price equal to marginal cost) implicitly opens the whole electricity system to competition. If businesses know real-price pricing is available, they will move to create products (like smart water heaters and air conditioning systems) that can take advantage of price variability and save customers money, while simultaneously lowering the cost of the overall system. A fledgling industry in demand response has already emerged around **demand charges**, but demand charges do a relatively poor job of matching incentives to actual costs and system performance. It is likely that, with real-time pricing, such existing systems could be reconfigured at low cost for a real-time pricing environment, and new ones would be developed.

Besides these extra benefits, we should generally expect that variability and intermittency of renewable energy would make real-time variable pricing considerably more valuable than it has been in conventional systems. Or, put another way, real-time marginal cost pricing ought to reduce the overall cost of renewable energy. To get a sense of how large these potential benefits might be, some preliminary results from a Hawai`i--based modeling effort were presented at the conference. These results have not yet been peer reviewed, but we present some preliminary results here, as we did at the conference, for the sake of full transparency.

The real-time pricing analysis builds upon an electricity planning model called SWITCH. Versions of SWITCH have been implemented for California, the Western United States and several other regions. The key advantage of SWITCH is that it simultaneously optimizes investment in generating capital — like power plants, windmills, solar panels and transmission lines — and real-time (hourly) operation of the system. In conventional systems that have enough flexible, load-following power plants, it is reasonably efficient to consider investment decisions separately from real-time operation decisions; only a frequency distribution of loads is needed to obtain a reasonable approximation of optimal investment. But when intermittent supply from renewables and storage become significant, investment and operation decisions become intertwined and must be considered jointly. SWITCH is the first modeling system to do this, however other models are beginning to incorporate these features critical for evaluation of systems with a high proportion of renewable energy.

To consider the value of real-time pricing, we extended SWITCH to simultaneously consider reserve requirements and a demand system that explicitly accounts for loads with the potential to be rescheduled to different times of the day, and that may help to satisfy system reserve requirements. A model for the demand side uses estimates of hourly load for three key end uses that can be made flexible with existing technologies: water pumping, water heating and air conditioning. The estimated loads are for the month of September in the year 2025, and were developed by Navigant for a demand-response report commissioned by HECO. These estimates were extrapolated to other months by assuming temperature-linked loads were attributable to these three sources. The extrapolation mostly reduces potentially flexible load shares for other months since September is among the warmer months. We then developed optimistic, pessimistic and middling scenarios for demand flexibility by assuming different shares of potentially flexible load (from these three sources) and other loads, would actually be flexible in practice under real-time pricing scenarios. The optimistic scenario assumes that most commercial and industrial-sized customers would adopt real-time pricing and technologies to implement flexible load shifting. The pessimistic scenario assumes that only a modest share would adopt. The cost and share assumptions for these scenarios are summarized in Appendix A., along with a detailed summary of preliminary results.

The difficult reality with planning for renewable systems with flexible demand is that we simply do not know what households and businesses would do in a real-time marginal-cost pricing environment, especially with the degree of variability and automation experts increasingly envision in the future. To some extent, the industry suffers from a chicken-or-egg problem: people may be hesitant to embrace variable pricing without proven technologies that can help them manage price variability and make it worthwhile; at the same time, innovators are unlikely to develop new technologies unless real-time pricing is broadly available or clearly imminent. Moreover, with true marginal cost pricing in a high-renewable system, it is easy to imagine times when electricity will be free or nearly so for long stretches of time when generation far exceeds demand. It is possible that new intermittent demand sources could arise to exploit such opportunities.

At this early stage the solution to the dilemma is to consider a wide range of assumptions about demand flexibilities and overall price sensitivity. Technologies will

change slowly over time and systems will have time to adapt investments to whatever arises. The goal is to show how variable pricing affects welfare and cost under a wide range of plausible scenarios, and see what kind of general conclusions arise. The full exercise (which is too extensive and preliminary to present here) will consider over 800 such scenarios (see Appendix A).

Some of preliminary results of the study indicate:

- By 2045, using HECO's projected costs, least-cost power system (excluding externalities) will include a large share of renewable energy, regardless of how it is priced. Under flat pricing, the least cost system would have a little over 60% renewable energy, and with dynamic pricing this rises to about 88%. The degree of demand flexibility has little influence on these results.

- While the projected cost of a 100% percent renewable system is costly today, and the cost of increasing renewable from 88% to 100% will be considerable even in 2045, a 100% renewable system in 2045 will still be less than a fossil system.

- The overall benefit of real-time pricing in a high-renewable system is considerable, equal to roughly 15-20% of a similar system with flat pricing. This benefit from real-time-varying prices is three to four times greater than in a traditional fossil system.

Appendix A gives some of the basic assumptions and more detail about the results. A full paper with these results and more will be published separately. Note that these benefits of real-time marginal-cost pricing assume otherwise efficient management of the system, and exclude the auxiliary benefits described above.

Consumer Choice

Some customers might be understandably wary of real-time pricing, especially when introduced for the first time, and if prices are determined in a manner that is not entirely transparent to them. For these reasons, among others, utilities and regulators can be reticent to offer real time pricing, despite success stories. Given these concerns, it seems likely that any attempts to introduce real-time pricing ought to be voluntary.

Within the domain of voluntary programs, however, there may be some debate about whether policies ought to be *opt-in* or *opt-out*. The *opt-in* framework would pose a menu of pricing structures, perhaps like the three options suggested above, but with the most traditional or familiar option—in this case, flat pricing---as the default option. Customers could then volunteer to switch or try out an alternative pricing structure, like time-of-use pricing or full-fledged real-time pricing.

A well-known problem with this approach is that a significant portion of customers will always go with the default option, even if it has long since been proven that another option ought to be preferred by most customers. A popular idea in behavioral economics is to "nudge" people in the right direction by setting a default that is most likely to be best for a certain customer class. The classic example concerns retirement

savings in 401K plans: for most employees with the option, it makes sense to participate in these plans, and many more enroll and save if enrolling is the default instead of not enrolling. Automatic enrollment as the default would be the *opt-out* approach.

Without adequate experience with a new real-time pricing framework, it may be hard to know which rate structure will be best suited to different customer types, and it may be difficult to know whether customers should be allowed to opt in or opt out of real-time pricing. It would be understandable if programs began as opt-in. Opt-out may be more advisable at a future point in time when appropriate default options could be made clear to customers. A growing body of evidence indicates that these options matter for electricity use and customer satisfaction.

Inefficient Rate Designs

Current rate structures can cause unintended consequences that may work against efficient integration of renewable energy. What are some of the most problematic rate structures? How do these influence efficiency as well as fairness? How could goals of these problematic rate designs be achieved in more effective manner?

Major Points

Commercial and industrial customers often pay a demand charge that scales with their peak load. Since peak loads differ across customers, and peaks may become less costly if aligned with times of plentiful renewable energy, these charges will become misaligned with system costs.

- ***Net-metering agreements, which typically allow customers with solar PV to buy and sell from the utility at the same price, do not account for the time-varying value of electricity. And because fixed costs tend to be folded into volumetric rates, net metering implicitly redirects some costs to other customers.***
- ***Feed-in tariffs typically pay fixed, above-market prices to early renewable energy producers, prices that far exceed their incremental cost of zero.***
- ***Block pricing, which charges customers a higher volumetric price depending on the amount of electricity used each month, can distort incentives for distributed generation. Equity motives for block pricing may be achieved more effectively and efficiently through other means, like means-tested energy assistance.***

While it is rare for retail rates to be tied to actual marginal costs, a few prominent features in retail tariffs attempt to account for variability. Sometimes rates can be used to achieve other social goals, like wealth redistribution, goals that might be better addressed with other tools. Some argued that these alternatives ought to be replaced with alternative rate schedules that better reflect true marginal costs, especially as these costs change with renewable integration. A few examples of poor rate designs discussed during the conference are briefly reviewed here. For more about billing adjustments that can make for inefficient policy, see these blog posts by Severin Borenstein, a participant in the conference.

Demand Charges

In many regions (including Hawai`i) commercial and industrial customers are charged a flat fee or per-kWh rate that depends on their peak demand (highest use over a 15-minute interval) during the previous year. For example, the University of Hawai`i, one of HECO's biggest customers, has a peak load of roughly 20 megawatts and an average load of 12.5 megawatts, using about 10,000 MWh of electricity per month on average. Currently the University pays about 17 cents per kWh for electricity, plus a monthly

charge equal to $21 per kW of peak load. So a typical monthly bill is $1.7 million for energy, plus a $420,000 demand charges. If the University consumed the same amount of energy with a perfectly flat load profile, reducing the peak from 20 megawatts to an average of 12.5 MW, it could reduce its demand charges by well over a third, or save roughly $162,000 per month.

The idea underlying demand charges is that the overall electricity system needs to satisfy the peak demand of all customers, such that the higher an individual customer's peak, the greater the system generating capacity needs to be. The obvious problem with demand charges is that not all customers peak at the same time. Some users may peak in the early evening while others peak in the middle of the day. Some users' demand may spike with hot weather, while others' may spike in cool weather. The system does not need to be sized to the sum of all customers' peaks; it needs to be sized to the peak of aggregate load, which is considerably less because use profiles differ.

Moreover, demand charges (a legacy policy tool) were clearly designed for a conventional power system. With high-penetration of renewables, peak demand will eventually occur during the *least cost* times when the sun is bright and the wind blows strong. As renewable penetration grows, the disconnect between demand charges and true system costs will become stark. The University of Hawai`i is a prominent case in point: its peak tends to be in the middle of sunny fall days, when the weather is warm and solar generation is high. Its load profile follows the sun and is a good complement for renewables. In this sense, the university is being overcharged for capacity. And while these fees ultimately help pay for grid management, they do not encourage the University to manage its load in a manner that would improve the overall system. Facing significant demand charges that amount to roughly 15 percent of its monthly bill, the university has a lot to gain by installing solar and thereby reducing its net-load peak and associated demand charges, especially for the first few megawatts. But the University's bill reduction will far exceed the reduction in costs to the overall system. Under the current regulatory environment, much of the university's savings from a solar installation would simply be pushed onto other customers, thereby giving rise to concerns about both fairness and efficiency.

Net metering

Net metering is a billing method used primarily for grid-connected customers with rooftop solar. These customers typically generate more electricity than they use during the daytime, with excess power supplied to the grid, lowering generation costs for the utility. At night, or other times when these customers use more electricity than they generate, they draw power from the grid. A net metering agreement typically charges a customer for the *net* consumption over the course of the billing period. If the customer generates more energy than they consume, the customer is sometimes compensated for the surplus, either as a credit for future months, or in the form of a check. Most net metering agreements, however, limit the amount of energy that households can sell back to the grid. In Hawai`i, customers cannot sell back to the grid, but they can roll over a credit from one month to another. Any surplus credit at the end of the year is forfeited.

There are two big inefficiencies and a major equity issue that arise with net metering. First, the marginal cost of power sent to the grid during midday may differ from the marginal cost of power drawn from the grid. For early solar installments, this was not much of an issue because midday loads were fairly high, and the difference between the value of power sent to grid and received from the grid was fairly similar. In some cases, exported solar may be worth more than power drawn from the grid. But this is changing, especially in places like California and Hawai`i; as solar penetration rises and the value (marginal cost) of midday power falls.

Second, net metering agreements typically limit selling of power back to the grid, potentially setting up a "use or lose" situation with customers who find they have installed more solar capacity than they need. In effect, these homeowners face a zero cost of electricity, while neighbors and others pay a positive price for energy. There are clear gains from trade in these situations that net metering prevents: customers with excess solar ought to be able to sell that excess to the grid at system-wide, marginal cost pricing, thereby restoring efficiency. Otherwise, these "use or lose" customers have a strong incentive to waste valuable electricity.

Some may argue that the number of customers with oversized solar installations is relatively small, and that their surplus may be limited. But the problem is potentially more substantial. Looking more broadly, in some places where sunny land is scarce, it may be possible that the social cost of rooftop solar is less than utility-scale solar, and it could make good economic sense to use rooftop space to the fullest extent possible. This may be the case on Oahu where either because of transmission constraints, high land values, a lack of competitiveness, or perhaps other reasons, bids for utility-scale solar installations can have little or no cost advantage relative to rooftop solar. Under current net metering agreements, however, customers have no incentive to use their roof space for solar capacities that significantly exceed their own use, so a lot of valuable roof space may be underutilized.

The third problem with net metering agreements is connected to the fact that fixed costs associated with the grid's operation, maintenance and billing are typically rolled into volumetric rates. As a result, when customers' net consumption falls, they don't just stop paying for the electricity generation from their panels, they may also stop paying for fixed costs, which embody the infrastructure they still use and still must be paid for. This problem may be minimal or non-existent in times of early adoption, if the marginal value of backfed solar exceeds the average cost of generation, helping to cover fixed costs. But as solar penetration rises, the incremental value solar energy is likely to fall. And in many regions, like Hawaii, the marginal cost of power is always far below the average cost, owing to very high operation and fixed costs. Under **revenue decoupling**, which is common in states like California and Hawaii with significant distributed solar penetration, these costs are passed on to other customers through upward price adjustments (more on revenue decoupling in the section, *Aligning Incentives*). Such a transfer of cost burden could be regarded as unfair if not adequately offset by the social benefits of clean energy. This effect can be exaggerated in regions with **block pricing**, an issue we address below.

Resolving these problems with net metering is not difficult. Allowing all customers with solar photovoltaic to buy or sell electricity at time-varying marginal cost would resolve the first two issues. California now requires solar customers to use time-of-use

pricing, a step in this direction. The third issue can be resolved with a fixed charge for use of the grid, one that does not vary with electricity bought or sold to the grid. At least in theory (and, in all likelihood, roughly true in practice), efficiency is unaffected by allocation of fixed charges. Thus, allocation of fixed charges can help address issues of fairness. An alternative would be to pay for fixed charges with general tax revenues, thereby letting the burden follow the progressivity of the state tax code.

Feed-in tariffs

There was less discussion of **feed-in tariffs** during the conference, perhaps because they are seen less when penetration is higher. Still, for completeness, we review the basics here and explain how they get prices wrong.

Feed-in tariffs are fixed-price contracts typically reserved for early, larger-scale installers of solar or wind that the utility or balancing authority is normally supposed to pay so long as the power accepted from the energy provider does not disrupt stability of the system. Because the contracted price can far exceed marginal cost of power (typically zero or negative for wind and solar), such contracts can create conflicting signals and lead to inefficient incentives. For example, a balancing authority may be tempted to curtail energy from fixed-price renewable contracts since the marginal price can be high. Worse, perhaps, is that renewable energy providers will anticipate that some unknown share of their energy will be curtailed, and therefore bid in a significant premium to the original fixed-price contract. The whole contracting process is thus more costly than necessary.

Again, there are simple solutions to problems with feed-in tariffs. Most obviously, providers could be paid the system-wide marginal cost of power, which will vary and evolve over time. Alternatively, contracts can be written as “take or pay” up front, so that the balancing authority is required to pay for the energy produced regardless of whether they curtail or not, thereby eliminating an incentive for excess curtailment. Since the renewable energy provider no longer faces uncertainty, it will offer a lower and more competitive price up front.

Because many feed-in tariffs are already in place, it would be useful to renegotiate the contracts. It should be possible to do so while making all parties better off. For example, a new, lower “take or pay” price could be negotiated that would increase the energy providers realized revenue, while giving the balancing authority an incentive to find creative ways to reduce curtailment. Alternatively, the balancing authority could make a one-time payment to the provider in exchange for the provider accepting system marginal-cost compensation for power going forward.

Block Pricing

To encourage conservation, and impart a degree of progressivity in the cost burden of providing utilities like electricity, natural gas and water, many municipalities, including those in Hawai`i, charge different per-unit prices depending on how much a customer uses. The first “block” of consumption in a month is charged the lowest price (this is 300 kWh for residential customers on Oahu), the next block a somewhat higher price,

and so on. Different municipalities can have different block delineations and price increases at each threshold, but the basic structure is almost always the same.

Block pricing will obviously differ from marginal cost pricing, and it will therefore create a certain amount of inefficiency. The purported fairness goals of block pricing, however, are compromised by net metering, for relatively wealthy households that use a lot of electricity have far more to gain by installing solar and reducing their monthly use. Like tax deductions, which have a greater value for households with higher income and marginal tax rates, solar installations will have more value for wealthy households. The disproportionate loss in revenue from wealthy households installing solar also needs to be made up through higher prices to other households.

With distributed solar and an eye toward systems with real-time pricing and demand response, some felt that block pricing structures would not be able to survive long. In California, and other places, the gap between higher-priced blocks and lower-priced blocks is being squeezed.

Concerns about equity can be addressed in other ways, such as through adjustments of fixed charges, as suggested above, or via means-tested energy assistance payments to low-income households. Even modest programs of this kind can be more effective than block pricing at helping low-income households.

Grid Defection

As solar photovoltaic, batteries, and small-scale generators become increasingly cost effective, and grid management costs rise, some electricity customers may find it economical to produce more energy themselves or disconnect from the grid altogether. As demand for electricity from the central utility falls, grid infrastructure and management costs must be spread over a shrinking load, raising average prices, potentially causing more grid defection. Under what circumstances would grid defection actually make economic sense? How might pricing policies cause more grid defection than socially desirable? What kinds of pricing policies would deter inefficient grid defection? Is mass grid defection plausible?

Major Points

- ***While many remain skeptical that large-scale exit from the traditional grid will be desirable for most customers, the pace of cost declines for solar PV and batteries has far exceeded expectations, and these declines are likely to continue as volume grows. Grid defection could be more likely that some believe***
- ***A key concern is "inefficient bypass," which refers to customers who bypass the grid even when the incremental cost of keeping them connected is less than the price such customers would be willing to pay.***
- ***If some customers leave the grid, efficiently or not, fixed costs of the grid infrastructure would need to be covered by fewer and fewer customers, possibly leading to more defection.***
- ***Efficient marginal-cost pricing combined with fixed charges and exit fees to cover sunk grid costs could resolve inefficient grid defection, but may be politically untenable.***

The rate of technological advance in renewable energy and battery storage technologies over the last decade has been truly breathtaking. If Swanson's law continues anything like Moore's law has, fossil fuels could become economically obsolete far sooner than many contemplate. The future is, of course, uncertain. We know technology will continue to advance but we don't know how fast. Yet, even today, while subsidies and mandates help to support growth of renewable energy, renewables can probably begin to compete without them. Some attending the conference, argued that advancing technology may easily overrun existing institutions and utility frameworks faster than these institutions will be able to adapt.

A main concern or possible drawback of rapid technical change may be grid defection: customers choosing to forego the electric utility and simply generate their own electricity with some combination of solar panels, batteries and small backup generators.

Why should grid defection be a concern? Two reasons: First, grid defection, especially in an environment where a grid of wires already exists but prices do not reflect marginal costs, could be inefficient. Where it may be privately beneficial for certain customers to bypass the grid and generate and store their own electricity, it wouldn't be privately beneficial if the prices were right. This is called **inefficient bypass**. (We elaborate on the distinction between efficient and inefficient bypass below.) The other problem concerns equity—how sunk costs of the grid plus its maintenance get reallocated to other customers, much as with net metering. More subtly, but perhaps more importantly, depending on how policy manages the prospect of grid defection, a modest amount of grid defection (efficient or otherwise) may snowball into much more grid defection that is greatly inefficient.

One early conference presentation pushed everyone to consider the possibility that, with continued technological advance, grid defection may become truly efficient. The exercise assumed continued technological advances to lower storage costs and solar power and a realistic consideration of variability. The presenter then developed a schedule of per-kWh average costs against a frequency of outages that would occur assuming a typical use profile. The analysis was conservative in a few ways, for it assumed the customer would not adjust electricity use as the available store of electricity became critical, no back up generation, and no subsidies. Still, high levels of reliability (albeit imperfect) might be achieved at a fairly reasonable cost (easily competitive with Hawai`i rates) if solar and storage costs were to fall over the next 5-10 years even half as much as they have over the last three or four years.[7]

To appreciate how rapidly technology is changing, consider what has happened in the two years *since* a well-cited 2015 paper in *Nature* documented the accelerating decline of battery prices. Since then prices have fallen even faster, 35% in 2015 and another 22% in 2016. Solar photovoltaic panels, now under 50 cents per watt, have already fallen to a point that installation comprises most of the cost. Even with installation costs, utility scale installations have already reached the "sunshot" goal of $1/watt, years ahead of schedule. A solar industry representative at the conference said that distributed rooftop solar could see more rapid price declines going forward as "soft costs," mainly associated with sales, design and installation, fall with remote sensing and automation of system design and planning. See, for example, this remarkable new tool developed by Google's Sunroof project.

Efficient Versus Inefficient Bypass

A key question raised in discussions about grid defection concerned when it would be economically efficient to bypass the grid and when it would not be efficient, even if privately desired by some customers. Some of the parameters around this distinction are clear; others are subtler. In almost all cases, it comes back to thinking about marginal costs, but in this case about the incremental costs of improving or expanding the grid, not generating an additional kilowatt hour of electricity. For example, consider the question of whether it is desirable to expand an electric grid to a new housing development. It would be economically efficient to do so if the overall benefit of

[7] The authors did not want to include these preliminary results in this report.

connecting the grid to the new development was greater than or equal to the incremental cost of grid expansion. It is important to keep in mind that expanding a grid to a new area, scaled on a per-house basis, might be greater or less than the grid's total cost on a per-house or per kWh basis. If the incremental cost were much less, yet the utility was required or otherwise felt obligated to charge all customers the same share of fixed costs (often through volumetric or per-kWh pricing), then we might have inefficient expansion or bypass of the grid.[8]

Note that in the case of an *existing* grid that does not require improvements or maintenance, the costs are already sunk and irreversible, so the incremental cost is zero. If charging people anything for the existing grid causes them to defect, it would be inefficient to charge them. Such a circumstance might raise sticky questions about who would be responsible for undepreciated book value of such assets.

The issues get more subtle and complex when considering grid upgrades. In Hawai`i, for example, some of the wires are buried, without conduit, beneath paved roads and sidewalks. Some of those wires are now approaching the end of their life cycle, and may nevertheless require upgrading to accommodate higher or bilateral flows of electricity that were never contemplated when first installed. Digging up old wires and replacing them, and repaving roads and sidewalks can be considerably more expensive than installing wires in a new neighborhood. The threshold for **efficient bypass** therefore may be lower for old neighborhoods than with new. However, it will surely be very difficult to convince an entire neighborhood to disconnect from the grid.

The possibility of mass grid defection sets up a difficult contest between emerging technologies. On one extreme, there is utility 2.0 -- a smart grid with demand response, time-varying, nodal (spatially-varying) pricing, and centralized storage that is managed in a sophisticated, forward-looking way. On the other extreme, there is full grid defection with rooftop solar and batteries, and maybe some individual backup generation for extreme events. The problem is that, if the second model turns out to be the efficient choice, perhaps for only a minority of customers, big investments in grid infrastructure could be for naught. This could be the worst of all worlds, a situation in which we ultimately take both approaches and waste tremendous resources. Such a scenario is all too easy to imagine.

Here's how it could unfold:[9] Suppose major grid investments are made, both to replace the aging infrastructure and modernize the grid, thereby raising rates and fixed charges. Higher rates then cause many customers to defect from grid and buy stand-alone systems. The fixed grid investments then must be paid for by fewer customers, further raising rates and causing even more grid defection, higher prices, and yet more defection. The system could unravel, and may do so *even if* having everyone on grid would be more efficient than the grid defected system. The whole utility infrastructure could become **stranded assets**—expensive redundant infrastructure that lacks an

[8] A formal theoretical treatment of bypass can be found in Chapter 6 of A Theory of Incentives in Procurement and Regulation by Jean-Jacques Laffont and Jean Tirole. The book also provides a thorough and formal review of incentive design for procurement and regulated entities like utilities.

[9] It seemed evident to us that a number of participants had gained a greater appreciation for the risks of grid defection, and the difficulties it would present in terms how stranded assets would be paid for. We gather that beliefs about the likelihood of such a scenario varied widely among participants (see exit survey comments).

income stream to pay for it. And, of course, the customers most hurt would be the last ones to defect, and these would almost surely be lower income households living in apartment buildings who cannot easily install rooftop solar. The political and economic fallout of such a dynamic would be devastating.

Note that the above story describes a situation where the first grid defectors did so because it was efficient. If price and contract structures encourage inefficient bypass, the system might begin to unravel more easily.

Solutions to this potential problem include exit fees or off-bill public financing of fixed costs and grid upgrades. Both options would surely be controversial, at least in part because there will be ambiguity about whether bypass is efficient or inefficient. Ideally, exit fees could be charged to customers wanting to leave the grid that would equal their share of undepreciated grid infrastructure costs. Such fees would seem to be especially important when contemplating grid upgrades. Households could opt to leave the grid without a fee before major upgrades took place, but would be required to pay a fee---essentially pay for their share of the upgrade—if they defected after the upgrade was in place. While such fees would be controversial, if they could be set fairly and efficiently (which assumes the grid investments themselves are efficient), would prevent spiraling, inefficient grid defection described above.

There may be some intermediate trajectories between the extremes of Utility 2.0 and mass grid defection. For example, we could keep existing wires in place to facilitate trading of power on a more limited scale, albeit with gradually increasing risk of disruption. Homeowners could instead invest in limited battery backup systems that could reduce flows on the grid and allow them to manage disruptions. This could limit investment while creating some redundancy between self-supplied backup and grid-supplied backup. There could also be more use of **microgrids**, which could vary across neighborhoods and interconnectivity with each other and centralized power.

Option Value and Uncertainty

A basic rule for investment is that an investment with a positive **net present value** is worth making; if its net present value is negative, then it is not worth making. This rule isn't quite right, however, when there is a lot of uncertainty and investments are irreversible—the investment cannot be easily sold or recouped if things don't turn out as expected. Power plants and grid infrastructure, especially today, are just this kind of investment. In these cases, often there can be an **option value**, which equals the value of *waiting* to make the investment decision in the future, when some of the uncertainty will be resolved. Today, for many kinds of electricity investment, there is likely to be a lot of option value.[10] Much of the uncertainty underlying that option value likely has to do with whether distributed or centralized systems will prevail over the long run.

The rational approach in a situation with a lot of option value is to move incrementally with certain kinds of decision-making. There were a few statements in the conference that emphasized "no-regret steps," which could be interpreted as constructive, low-cost policy tweaks that could aid transition to either kind of system,

[10] A classic albeit technical book summarizing this literature is *Investment Under Uncertainty* by Avinash Dixit and Robert Pindyck.

optional real-time pricing, or investments that would provide value under a number of alternative futures. Expensive grid upgrades in Hawaii, for example, might be particularly risky right now given our high conventional prices and the fact that these costs will be entirely sunk and stranded in the event of full–fledged grid defection.

Rising Fixed Costs

A growing omen of potential grid defection can be seen in the steadily rising gap between retail prices and average generation costs, a trend that seems to be accelerating with the growth of renewable energy. This trend is evident in Hawai`i, where the average cost of fuel plus purchased power is only 8 to 9 cents per kWh, while the average residential rate is around 26 cents per kWh (Figure 2). Before 2007, this gap was fairly constant, owing mainly to the fact that demand for electricity was growing over time, allowing the utility to cover its growing costs of operating the grid while this component of price remained constant.

Change began around 2006, when rising oil prices relentlessly pushed up fuel costs and the generation component of price. By 2008, the retail price averaged over 30 cents per kWh, and 34 cents per kWh for residential. High prices, coupled perhaps with the Great Recession, caused demand for electricity to fall fairly dramatically over the next few years. Then, with gradually rising fixed costs being spread over gradually fewer kilowatt hours sold, the gap started rising.

Installations of distributed solar took off around 2011 and reduced loads from that can explain some of the rise in the gap. Most of it, however, can be attributed to the reduced quantity demanded, presumably because high prices caused customers to invest in energy efficiency or otherwise conserve. The trend could accelerate if distributed systems continue to grow.

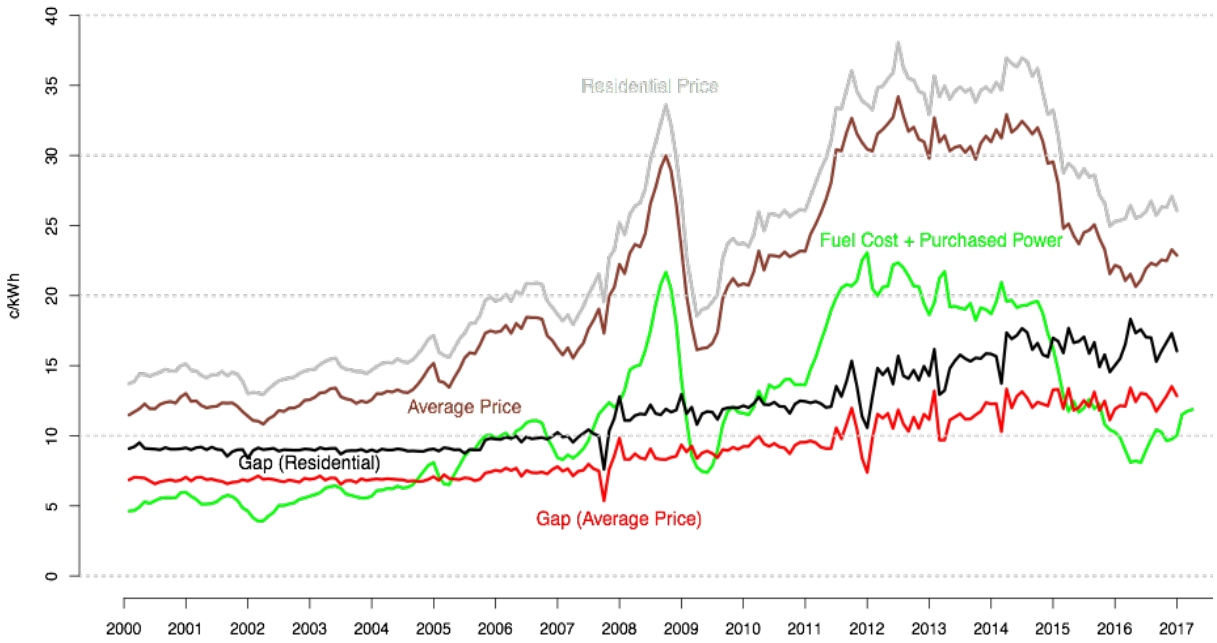


Figure 2. A growing gap between generation costs and retail prices. The graph shows average price for residential customers (grey) and all users (commercial, industrial and residential, in brown) from 2000 through early 2017. The prices are further decomposed into a fuel charge and purchased power (green), which accounts for generation costs, plus a "Gap" which accounts for all other costs (power plants, transportation and distribution, operations etc.), which are mostly *fixed*, i.e., do not vary with the amount of electricity consumed. The gap has been rising over the last 10 years in large part because overall demand and generation has declined, thereby causing these fixed costs to be averaged over fewer kilowatt hours sold. Only a small share of this decline stems from distributed solar; the rest of it likely stems from energy efficiency improvements that were motivated by high and volatile oil-driven price spikes over the last decade.

Aligning Incentives

Currently, regulated utilities are allowed to set prices in order to collect revenue to cover approved operating expenses and a "fair rate of return" on capital investments. In many cases, regulated utilities have little incentive to control costs. The more distributed nature of the future utility is putting greater stress on the traditional regulatory model. How should incentive structures change so that the utility of the future will be motivated to manage the grid in cost effective way?

Major Points

- ***Utility regulation has always struggled with an inherent tension between keeping prices low while providing utilities an incentive to control costs appropriately.***
- ***Cost-of-service regulation may work adequately when the utility has little private information about costs and the scope for innovation is limited.***
- ***Given uncertainty about continuing, rapid technological advance, it is objectively unclear what kind of grid enhancements are needed, and we should expect the regulated utilities to come down on the side that maximizes its own investment while minimizing that of competing interests and resources.***
- ***Many suggested a turn toward holistic, customer-oriented, performance-based incentives, while others expressed concern that poorly designed incentive structures could lead to windfall gains to the utility that could be difficult to reverse.***

When thinking about winners and losers in the transition toward renewables, the utility and the regulator are the two most important stakeholders, since they are on the front line of making decisions to manage the transition. It is critical that the utilities' incentives align with social goals of affordable renewable energy. As Elon Musk stated at a recent meeting of U.S. state Governors:

> *You can't do these cost-plus sole-source contracts, because then the incentive structure is all messed up… you're incenting the contractor to maximize the cost of the program because they get a percentage… [it's] Economics 101: Whatever you incent, that will happen…"*

The quote pertained to contracts with NASA, but some similar challenges exist with utility regulation. The utility is, essentially, under a sole-source contract with the local public utilities commission (PUC), and in most cases utilities earn profit by increasing their capital base. While generation and transmission are increasingly purchased through a competitive bidding process or full-fledged markets, distribution is typically financed through cost-of-service regulation.

Today, with a growth of distributed generation and "smart grid" systems, the utility's incentives—the source of its profit—increasingly conflict with social interest. As a

result, there is considerable talk about utilities needing a "new business model." But since private utilities' profits connect to the way they are regulated, what may be needed is a different regulatory model. Perhaps we could call it *PUC 2.0* instead of Utility 2.0.

Much has been written about regulation of **natural monopolies**, and a number of different regulatory models exist.[11] Today technological change and new competing interests, especially from distributed resources like rooftop solar, distributed batteries, and smart devices that could enable demand response, cast a new and different light on the old tension that exists between the utility and the regulator. It's time to take a hard look at this regulatory structure and consider adjustments.

Conventional Regulation

In conventional utility regulation, the traditional focus is on setting a price cap and controlling the utility's costs. In regularly scheduled **rate cases,** the public utilities commission evaluates whether the prices the utility wishes to charge are no greater that necessary for covering appropriate operation costs. All major capital investments must be approved separately, and if approved, earn an allowed **rate-of-return** plus depreciation cost. Because the utility normally earns an above-market rate of return on its capital investments, cost-of-service regulation requires strict prudency review by the public utilities commission. Without it, the utility effectively has an implicit incentive to maximize its own capital costs. For this reason, regulators have the authority to disallow recovery of capital and operation costs if they find them to be imprudent or unnecessary.

In some cases, regulators use performance-based incentives. These typically allow a utility to keep some or all of its cost reductions between rate cases, thereby growing its profit temporarily. Savings are supposed to get passed on to consumers in subsequent rate cases, when allowed cost recovery is ratcheted down to the lower cost baseline achieved by the utility. Sometimes incentives target particular aspects of operations, like average heat rates of their power plants, a technical measure of efficiency. A simple but inefficient way to manage a utility and maintain stability is to simply keep more power plants than necessary in operation, but running at minimum capacities, thereby leaving plenty of room for up reserves for a contingency event. Operating power plants this way can be inefficient, and will show up in lower heat rates. Under some kinds of **performance-based regulation**, a utility can keep a share of the savings gleaned from beating target heat rates while still maintaining stability.

Revenue Decoupling

Under standard "price cap" regulation, there are incentives for utilities to encourage customers to use more electricity. By doing so, they grow profits, at least when the regulated price exceeds marginal cost as is often the case. While this feature usefully

[11] The linked book by Ken Train provides an excellent review and is freely available online. Two other prominent books are by Berg and Tschirhart and Laffont and Tirole. Also see this review by Paul Joskow. A superb and more readable (less formal and mathematical) review of the issues by Joskow and Schmalensee, directed mainly toward legal scholars, can be found here (may be gated).

gives the utility an incentive to keep costs low, it can conflict with socially-minded efforts to improve energy efficiency, which many regard as the "low hanging fruit" for reducing greenhouse gas emissions and other pollutants. Efforts to encourage efficiency therefore conflict with the utility's profit motive. Similarly, rooftop solar and other forms of distributed generation reduce the utility's sales and potential profit.

Revenue decoupling is designed to alleviate this tension, by fixing an allowable level of *total revenue* to cover operating costs and return on investment instead of an allowable *price per kilowatt hour*.[12] Allowable revenue is based on projected quantity of sales and cost of provision, but if quantities turn out greater or less than what is projected, the allowed price adjusts in the opposite direction to keep revenue constant. The idea is that such a mechanism diminishes the utility's incentive to discourage energy efficiency or distributed generation.

There are a few potential problems with revenue decoupling. First, it may diminish the utility's incentive to control costs and thereby expand sales, since it must lower prices if sales increase. Second, because revenue and cost baselines are revisited in each rate case, the incentive to discourage efficiency and distributed generation is not alleviated. In the long run, all manner of distributed generation, as well as storage, and demand response, compete with the utility's own investments and thus its potential to generate returns. For example, in the modeling exercise described in *Getting Prices Right* and Appendix A, most of the value from demand response comes from reduced need for battery installations, batteries the utility might otherwise buy and earn a rate of return. Distributed private storage also competes with the utility's grid upgrades, since it would limit back-feeding and flow of power into and out of circuits.

Problems with Rate-of-Return Regulation

Efficiently and fairly managing the utility of the future is a complex and challenging task, one that is unlikely to be undertaken well if profit motives conflict with it. Today that conflict is palpable, and most of that conflict comes from the fact that the utility profits derive mainly through making capital investments. While a utility can be enthusiastic about expensive grid upgrades, some of which may be needed for a smart, modernized, renewable-friendly system, the utility does not have an incentive to carefully weigh uncertainty, option values, and difficult tradeoffs between centralized storage, distributed storage, demand response, and a wide range of possible grid infrastructure upgrades. If the utility can hope to have an ownership stake in any of these devices, it has a strong disincentive in making any competing components of utility 2.0 work.

In theory, the allowed "rate of return" is supposed to be set at "break even" level, nothing more, and nothing less. If the rate is too high, a profit-maximizing utility will have an incentive to invest too much; if it is set too low, a profit-maximizing utility will not be able to attract investors and could be financially compromised. As a result, the rates tend to be set high, often justified by adding a substantial risk premium to typical lending rates to accommodate equity ownership. As a result, utilities have a strong incentive to

[12] Note that allowable revenue typically net of fuel costs and purchased power, which is a pure pass-through to customers.

overinvest, and to discourage competing investments by others. These deleterious incentives must be tempered by regulatory approval of proposed investments.[13]

While this conflict between utilities and regulators has always existed, competition with distributed resources is new and more complex. Operation and management of traditional power systems has become a fairly well honed enterprise. Costs of power plants, fuel, transmission and distribution lines are reasonably clear and common knowledge. Software to optimize new investments and operation of traditional systems is widely available to both utilities and regulators. There was relatively little room for utilities to manipulate decisions toward their greater advantage. This kind of environment might have been reasonably well suited to rate-of-return regulation.

Rapid technological advance, and especially growth in renewable energy, storage and smart control systems, has changed this dynamic considerably. System management is becoming more complex, software is outdated, and uncertainty about future technological change makes it much more difficult to discern the most appropriate investments going forward. Perhaps most importantly, given uncertainty about continuing, rapid technological advance, it is objectively unclear what kind of grid enhancements are needed for the utility of the future. In the current regulatory environment, we should expect the regulated utility to come down on the side that maximizes its own investment while minimizing that of competing interests and resources. And because the utility will always be better informed about operation of the overall system, it could be difficult for the regulator or other stakeholders to clearly justify alternative paths.

Ownership Structure

An extreme form of regulatory change could involve a change of ownership. Not all utilities are publicly traded for-profit companies. Some are government-run municipalities and others are cooperatives, non-profit entities that are owned by their customer base. These alternative ownership structures can have their own incentive problems. While we focused mostly on regulated, for-profit utilities, we did hear about remarkably competitive contracts for dispatchable solar that the Kaua`i cooperative had secured. The costs of the small island cooperative's dispatchable solar *with battery* installations are roughly on par with costs of HECO's contracts for passive solar *without* battery. Even lower prices—less *than one-third* the price Kaua`i paid—are now being reported for subsidized solar with battery (4.5 cents/kWh) in Arizona. There are surely many factors that go into the competitiveness of renewable energy installations, but ownership structure and overall regulatory incentives may play a role.

A clear advantage of these alternative ownership structures is that they have lower costs of capital (more on this below). This advantage will grow larger as fuel costs decline and capital costs comprise a growing share of overall costs. Most regulatory discussion at the conference, however, focused on regulation of for-profit utilities, markets and more generic rules of governance.

[13] Many call this the "Averch-Johnson" effect, after the authors of a famous paper that first articulated the problem.

New Forms of Performance-Based Regulation?

Some at the conference argued for a greater role of performance-based incentives, in part because regulators cannot easily judge the appropriateness of all needed investments, and in part because operational decisions may need to be carried out in a dynamic and rapidly changing environment. Utility profit, many argued, ought to be tied directly to customer-oriented outcomes. Some emphasized caution, however, noting that in the past performance-based regulatory incentives had led to unnecessary windfall profits by utilities that required protracted legal struggles to reverse.

It's not clear whether performance metrics and compensation mechanisms used in the past are ideal for a transition to utility 2.0. Traditional utility regulation presumes existence of a self-contained natural monopoly, wherein a single business can unilaterally provide a good or service at lower cost than multiple businesses. Utility 2.0, in contrast to standard natural monopoly, imagines all manner of customers—through distributed storage, generation, and demand response—all playing a role in the integrated enterprise of electricity generation and supply/demand balance. A single entity is needed to coordinate and manage the integrated system, and to manage distribution through a single set of wires. It is essential that the coordinating entity of utility 2.0 possess incentives that align with the broader interests of the overall system and public interest.

The crux likely comes down to defining the correct performance metric. The most important metric is probably the oldest one: cost. Under cost-of-service regulation, the utility has little or no incentive to find creative ways to cut costs while maintaining or improving quality of service. Under traditional regulation using the "ratchet" mechanisms described above, utilities have a short-run incentive to reduce costs, but may be loath to cut costs for only temporary gains. Instead of letting the utility keep all cost savings between rate cases, the PUC might let it keep a gradually declining share, such that some gains are maintained for a sufficiently long period of time.

It is also worthwhile considering the kinds of costs targeted by performance-based regulation. Normally performance-based regulations apply to operational costs, like labor or **heat rates** on generators, not capital expenditures. Thus, the utility might grow profits by reducing labor costs or operating its mix of generators in a more efficient manner. But if the public utilities commission approves capital expenditures, the utility is allowed a fixed, above-market rate of return on that investment regardless of its social benefits. Thus, a utility like HECO, might gain marginally if a new demand response program allows it to modestly improve its heat rates. But it may well lose more than it gains if such a program would eliminate the need for grid improvements or investments in batteries, for which it would otherwise be allowed a rate of return.

To the extent that the utility can influence which contracts are signed with third parties, or what kind of distributed resources are added to the system, it should care not just about its own costs, but others' costs and benefits too. The utility might also be compensated based on quality of service, which may come down to the frequency and duration of scheduled or unscheduled outages, frequency of billing complaints, customer service metrics, or time waiting for distributed resource contracts to be signed.

One participant suggested that the utility's profit ought to be tied to model-based dollar-valued metrics of total social benefit—estimates of what truly competitive market

would achieve (like those reported for the real-time pricing study in the appendix), probably including accounts for losses from disruptions. Such metrics would clearly reward the utility with lower costs and prices, and would encourage it to use all means and resources at its disposal to improve overall efficiency of the system, whether the utility owned those resources or not. Models are becoming more sophisticated, and similar models are in fact used in control rooms to optimize management nationally. It should be possible to create such metrics even if they have not been used in the past.

A problem with this approach is that unforeseen changes in demand or in technology could complicate surplus metrics. Changes in overall surplus attributable to utility management may be difficult to separate from external changes, and the differences could be substantial. At this stage, preliminary ideas remain too vague to ascertain their potential viability. Many thirsted for more concrete discussion about the particular details and metrics that should be used in performance-based regulation of Utility 2.0.

Are Rates of Return Too High?

Over time, as market interest rates have fallen, the gap between market rates and utilities' allowed rate of return has grown larger (Figure 2). Regulated rates of return, set during rate cases, occur at long and sometimes irregular intervals. If rates are trending down, then rates set historically will be too high. There may be any number of reasons why rates have fallen more slowly than market rates. One problem is that, during rate cases, experts doing analysis to justify rates of return may look historically or at other utilities. In a downward trending rate environment, this will slow down adjustment even more than it would given irregular timing of rate cases.

Another more subtle explanation is that, when interest rates fall, returns on equity (stock and other asset values) increase, even as *prospective future* returns fall with market rates. The reason is that lower interest rates cause future values to be discounted less, increasing their present value. This is similar to the idea of bond, home or land prices rising as interest rates fall. Thus, backward-looking rates of return on equity can increase markedly even as forward-looking rates of return decline.

There are solutions to this problem, just as there are interests that will work to keep rates high. One possibility is indexing rates of return to a market rate, such as state municipal bonds, plus a small premium (utilities are considered safe investments with small asset betas[14] and low risk premiums). Another possibility is for the state to issue bonds and then lend the money to the utility on a zero-profit basis for needed investments. Additional resources connected to performance could determine shareholder returns. It might also be possible to forgo setting rates of return entirely, and instead connect the utilities compensation to a more comprehensive measure of overall performance as suggested above. Investments would not be compensated by some allowed rate of return, but by an improvement in performance that would be

[14] An asset beta is measures how its return covaries with the overall market (e.g., the S&P 500 index). When asset returns bear little association with the overall market, as they do with utilities, they have a small beta, which means its risk is easily diversified, so the risk premium is small.

rewarded based on a measure of its social value. While some states are experimenting with new regulatory mechanisms, examples to date are limited.

Managing the Transition to Utility 2.0

Who gains and who loses from the transition toward renewable energy and a modernized grid that can manage it effectively? What are the political and economic obstacles to this transition? What kind of process can best manage and resolve tensions between the various interests and stakeholders?

Major Points

- ***The transition from fossil fuels toward renewable energy is both technically and institutionally complex. Such transitions require wrestling with difficult choices in a way that employs solid analytics in a transparent and public regarding way.***
- ***Complex transitions can be managed with a range of policy mechanisms, ranging from "top down" approaches such as mandates to "bottom up" approaches that may emphasize performance-based incentives.***
- ***While much of the policy emphasis has focused on renewable energy goals, more attention needs to be directed toward implementation of those goals.***
- ***There are roles for both experimentalism (trying out new policy tools to see how well they work) and incrementalism, no-regret steps that move things forward.***
- ***Successful transition requires adaptive institutional with strong leadership that is willing to be pro-active instead of reactive.***
- ***Successful transitions require constructive stakeholder and community engagement that clearly defines the issues, develops the right forums for discussion at the right time, and skillfully facilitates productive interaction.***

In an ideal but probably less interesting world, solutions to complex problems would result from consensual agreements followed by their implementation. In the world in which we live, consensus can be hard to come by, and once found is likely to be followed by protracted struggles over implementation. Such struggles are already clear as we integrate more renewables into existing electricity systems. These are understandable in an environment of great uncertainty, rapid technological advance, divergent beliefs about climate change and the contribution of pollution from traditional fossil fuels, and perhaps most importantly, a wide array of competing interests vested in power generation, transmission and distribution infrastructures.

One attendee with extensive management experience quoted Peter Drucker (and perhaps Abraham Lincoln) who stated that, "The best way to predict your future is to create it." We need to be clear eyed about the challenges of the transitions needed to create a renewable energy future while also striving to join knowledge about the best paths forward with skill in increasing the odds those paths will be followed. Coupling knowledge with public-regarding actions is important in many areas, and is unquestionably so in addressing rapidly evolving energy technologies and institutional change, where the impacts on communities, nations and the planet will be substantial.

Complex transitions require dealing with difficult issues. Transition issues that emerged explicitly or implicitly from this conference are discussed here. In looking at each it also may be helpful to think about the degree to which these transition issues are unique to renewables or, conversely, what other kinds of transitions can shed light on this one.

Transferring Lessons Across Systems

This conference was held on a Pacific island in a state that has committed itself to 100% use of clean and renewable energy, within a relatively short period of time. Lying beneath many of the discussions were the twin questions of (1) what parts of the Hawai`i experience were relevant to endeavors in other places, and (2) how much could Hawai`i learn from other regions such as California, ISO New England, or Ireland. These questions are reflections of the overarching transition questions of whether strategies that have been successful in one place can be lessons in other settings, and the best ways of facilitating that. For example, can lessons learned from early renewable energy adopters in Europe help other areas "leapfrog" some problems? Are there "no regret" strategies that have a degree of universality?

There is a relatively large literature on how change occurs. Most of it addresses organizational changes rather than those occurring in larger, multi-organizational systems. One resource that seems relevant to both organizations and systems is William Bridges' *Managing Transitions*. Bridges argues that the problem is not change, but the transition process. What he refers to as "transition time" involves three stages:

- *Letting go* — Characterized by denial that change is occurring, and resistance.
- *The neutral zone* — Characterized by disorientation as changes become real.
- *Launching a new beginning* — Characterized by the release of energy that is more consistently in the direction of new endeavors.

A number of prescriptions for "managing transitions" emerge from Bridges' framing and the stages he defines seem relevant to understanding the turbulence of change in the electricity sector. The purpose of referring to Bridges, however, is not to elevate him as a resource. It is to point to the importance of asking how existing knowledge about institutional transitions can be used to join research about renewables, electricity systems, and regulation to facilitate public-regarding changes.

Transitions and Politics

If a system can be made more efficient, a bedrock principle in economics implies that it's possible to make everyone better off. It is therefore an understandable and worthy

goal to, as one participant suggested, depoliticize the transition process and emphasize good analytics, independent decision-making and credibility, all in an effort to find a mutually beneficial path. Yet, even if theory tells us that such a path is possible, politics and real-world pragmatism mean that change almost inevitably will bring about both winners and losers. And, of course, various interests and stakeholders, some of which are more powerful than others, will likely attempt to shape the process to their own greatest advantage.

The most viable path toward a more mutually advantageous and socially beneficial transition is to make the process inclusive and transparent, with solid, impartial analytics at the center. The challenge therefore is not to eliminate politics, but to manage it a responsibly, such that vested interests are appropriately weighed against each other and mutually beneficial opportunities are maximized. The overriding goal ought to be that who gets what, when, and how -- the basic political and economic questions -- will be determined by a process that is widely seen as fair, informed, public-regarding and therefore legitimate. It is reasonable to hope that a transition can be guided by enlightened self-interest, one that takes into account broader community and societal concerns. Even thought of this way, however, several important issues will need to be taken into account.

First, what are the key interests and where are most conflicts likely to arise? Grid defection was pointed to as an area ripe for conflict because it sets "What's good for me" against "What's good for everyone." One Hawai`i participant referred to the disputes between liquefied natural gas (LNG) and renewables, as well as NIMBY reactions and cultural concerns that prevent people from thinking holistically. Some local residents on the North Shore of O`ahu`i, for example, have objected to installation of wind turbines there, while residents on the island of Hawai`i (the Big Island), are sensitive about geothermal energy, both due to cultural factors (many Native Hawaiians believe geothermal development offends the fire goddess Pele) and problems with noxious hydrogen sulfide gases.

Second, which of the paths to the integration of renewables most recommended by academic research and practitioner knowledge – such as demand response and variable pricing – could create undesirable forms of politics? This would depend on how different interest groups perceived themselves to be affected by following those paths. Equally important is how these responses will affect what is recommended? For example, as mentioned above, residential customers initially may feel skeptical and vulnerable in a real-time pricing environment. For this reason, plus the fact that more that two thirds of demand is comprised of commercial businesses, it would seem to make sense to target larger customers first, since they may be better situated to take advantage of such a program. At least so far, policy has gone in the opposite direction in Hawai`i, with time-of-use rates being proposed for residential customers and little discussion of real-time pricing. Beneath the surface, a case of diverging interests may be found in the utility's current incentives – a successful demand response program could undercut some of their own investment possibilities.

Finally, given the reality that no real change benefits everyone, what is to be done about the losers? This question is both about fairness: What should be given as compensation for loss? And strategy: What will reduce resistance to the needed changes? On the consumer side, ideas from behavioral economics and democratic

theory are useful, such as giving customers choices, sensible default options, and ample information to help them make informed decisions. These questions will also arise with competing business interests: the utility, different sources of power generation and storage, and the various interests that profit from development or redevelopment of transmission and grid infrastructure.

Mandates Versus Prices

There was some conference discussion about policy mandates versus the pricing approaches often favored by economists. Many states push renewable energy through renewable portfolio standards that set certain targets and impose penalties if mandates are not achieved. Alternative approaches include carbon taxes or a "cap and trade" systems for pollution permits. Either approach can cause adoption of new technologies to be too fast or too slow in terms of economic efficiency, for there is always uncertainty about what the right price or right mandate ought to be.[15] Regardless of the approach, it is important for policy to be clear in prescribing desired outcomes, as opposed to mandating specific technologies or infrastructures. One person noted, for example, that in the Hawai`i case it took a long time to get the rules in place for its renewable portfolio standard, but that the top-down policy strategy was valuable.

The debate between mandates and incentives should not be seen as a stand-in for top-down versus bottom-up approaches to change. Prescriptive, top-down mandates may make sense in some cases. For example, energy efficiency standards that make economic sense for most customers can be both simple and cost-effective. Mandates can also target goals without prescriptions for how such goals ought to be achieved; penalties for not achieving goals would then provide the incentive. This approach leaves considerable room for negotiation among competing interests in a manner that shares costs and benefit and tends to improve efficiency.

One problem that has emerged with mandates that govern renewable portfolio standards concerns the metric used for "percent renewable." In California, the metric excludes all distributed generation, which may have the effect of undercounting the share of electricity production coming from clean renewable energy. In Hawai`i, the percent renewable is measured as the total amount of renewable energy, including distributed renewables, divided by a baseline projection of centralized generation managed by the utility. Thus, distributed generation counts in the numerator of the calculation (amount of renewable energy), but it reduces the denominator (total or gross electricity sales). As a result, rooftop solar increases the percent renewable more than does utility scale solar or wind. It is easy to imagine where, by this metric, Hawai`i could legally achieve "100 percent renewable," while still generating half of its electric power from fossil fuels.

Regardless of the motivation, a number of unintended consequences could stem from having mandates tied to metrics that depart from the claimed goals of a program. For example, in Hawai`i, the metric does not just implicitly favor distributed renewable energy over utility-scale installations; it may also encourage inefficient grid defection

[15] This famous paper in environmental economics tackles the question of whether prices or quantities ought to be regulated.

and more burning of fossil fuels. Large scale customers could choose to buy their own, small gas generators, buy liquefied natural gas (LNG) currently imported in containers, and pair them with subsidized solar panels to leave the grid. One reason this could be privately economic but socially deleterious is because natural gas generation by individual customers, like solar, does not count under the renewable portfolio standard. Another reason is because the utility has not been granted permission by the PUC to convert existing plants to natural gas, or build new ones, for fear that such investments soon will be obsolete. While the calculation for whether LNG should be used as a "bridge fuel" in Hawai`i is a difficult one that embodies a lot of uncertainty and difficult tradeoffs, the decision should not be compromised by poor policy metrics.

Goals Versus Implementation

In popular discourse and press coverage about renewable energy, there has been considerable discussion about the appropriate goal: how much renewable energy or how big of a reduction in fossil fuel use should be achieved by some point in time. While many see the value in having clear (and appropriately measured) goals, many at the conference made the case for moving beyond questions about goals and toward the details of implementing them. Especially given the rapidly falling costs of renewables and storage, it is becoming increasingly clear that costs, benefits and unintended consequences may hinge more on how policy is implemented and less on the particular goal. Managing a grid with renewable energy, demand response and storage means entering an as-yet unfamiliar world. Without the right policies, the transition could be much more costly, politically, socially and economically, than it needs to be. It is important to sweat the details and move the conversation in this direction.

Incrementalism and Experimentation

The conference considered a number of ways to better integrate renewables, and each has different potential strengths and weaknesses. When are incremental transitions preferable to promoting rapid change? When is it possible to experiment with approaches that appear to be desirable? If experiments are desirable, how can experimentation be undertaken in manner that is scientifically rigorous, constructively useful for policy, and politically viable?

Real time pricing was referenced as something that could be a good start. Still, questions remain about how such prices ought to be determined, who would benefit, and who could lose. Optional participation and targeting of customers most likely to benefit and most likely to provide meaningful impact on grid management were discussed. Randomized controlled experiments might accurately gauge the impact of such policies, but would slow implementation. There is also concern that it would take time for smart devices to be developed that could better take advantage of real-time pricing, something that experimental introductions are unlikely to inform. Moreover, a number of experiments have already been successfully implemented and it's not clear what more needs to be learned. Alternatively, optional dynamic pricing could be introduced with minimal complexity, using system lambda pricing, likely causing little disruption to the current system. This was labeled the equivalent of "training wheels."

Another example was provided in the state of Hawai`i's "aspirational" goal of 100 percent clean and renewable energy that is intended to be reviewed periodically. This characterization of the goal underscores the need to revisit interim targets and, depending on how things evolve, make adjustments to improve efficiency and fairness.

Moving away from a cost-of-service regulatory model toward performance-based incentives with greater emphasis on customer outcomes was viewed as requiring a gentle transition. This kind of change might benefit the public utility while giving customers a reason to stay connected to the grid. Among other things, gradual transition is needed to ensure sufficient market stability. Many urged more discussion of specific actionable steps that could be taken with regard to the regulatory model.

Strong Leadership and Adaptive Organizations

Leadership can mean different things, but here refers to the capacity to go beyond everyday management to (1) recognize opportunities and challenges and (2) mobilize resources to make the best use of the opportunities while reducing the downside of the challenges. Leadership involves transforming complexity into a compelling vision, a strong sense of responsibility for outcomes, the willingness to take justifiable risks, and an ability to build committed partners and mollify dissenters. This kind of leadership is valuable at all levels of private or public organization. In any transition to renewable energy it will play a critical role in identifying urgent actions, utilizing relevant information, communicating clearly, building synergies across stakeholders, and ensuring consistency of effort over time.

Adaptive organizations have the flexibility to move beyond familiar ways of doing things -- ways that may have worked well in the past – to make the changes needed for the future. In this conference considerable attention was given to the importance of this adaptiveness in key organizations: the public utility commission, the state agencies directly involved with energy policy and oversight, and the public utility itself. For a transition to occur needs to be less bureaucratic, less bound by rules no longer relevant, and prepared to do things in new ways. It was argued, for example, that it no longer makes sense for the Hawai`i Public Utility Commission to wait for issues to be brought to it, and that its orientation to regulation must shift from *reactive* to *proactive*. This change in turn can be expected to have profound effects on other parts of the energy system.

Organizational adaptiveness with respect to the integration of renewables carries with it, as do other issues with a broad public interest, an obligation to remain responsible and accountable to what is most beneficial to the general well-being of affected communities. The goal is *responsible* flexibility, not just flexibility.

Stakeholders and Community Voices

It was clear throughout the conference that the views of diverse stakeholders need to be understood. Stakeholders include actors involved with the system that produces, transmits and distributes electricity, and whose interests will be affected by policies or decisions relating to energy. It is clear from, to take two examples, California and ISO New England, that as these energy systems evolve there will be more and more

stakeholders that expect to be taken into account. Successful transitions will require knowing all stakeholders, defining clearly the issues to communicate about, the right timing and forums for discussion, and skill in facilitating productive interaction.

The conference included a number of references to the importance of community input. Virtually no one living in a liberal democracy would disagree with the proposition that the communities impacted by decisions about the introduction of renewables should have a voice in those decisions. The question is not "whether", but "how" and "when". These questions are significant because if community input is obtained at the right time the result can be (1) better informed decisions that are (2) more likely to be accepted as legitimate. It is, of course, difficult to get people's attention, as dismal rates of public participation regularly demonstrate. Therefore serious attention must be given to what is needed to make attractive public engagement with renewable issues and decisions.

Creating the conditions for an informed community voice is another challenge. "Community hearings" often include subtext collisions, usually not addressed, between different mindsets. One mindset comes from professionals with hard-earned expertise who take pride in providing evidence-based opinions. Some professionals are also highly paid consultants who favor the interests of a particular constituency. The other is found in the community members whose reactions are based less on being well-informed than on a broad set of core values coupled with concerns about how something will affect them. From the point of view of the expert, community opinions sometimes can be seen as irrational or uninformed. From the point of view of the community participant, expert views can be seen as insensitive and out of touch.

Renewable energy, because it is closely tied to environmental concerns, can elicit strong feelings that may align with political or group identity, and can make productive dialogue even more difficult. This was seen in reactions to the prospect of offshore wind in the Islands. Some in the community believed that, despite the fact that hearings were being held, decisions had already been made to move forward with it. Trust, which has to be built up over time but is lost easily, is clearly a key factor.

As this overview makes clear, the transition to renewables will continue to be complex and challenging. Some of the issues that arise will require knowledgeable scholars and practitioners to move outside of their comfort zones to try and ensure that the actions taken are well founded. In this spirit, the conference organizers have formed a small working group, made of both scholars and highly experienced practitioners. For the time being we are calling it the "Governing Green Power Steering Group". It's goal is to carry forward the conference's work by attempting to identify and prioritize key issues, openly strategizing about research agendas on the basis of those priorities, and bridging to stakeholders and the community at large in a variety of ways. We also aspire to interact with, learn from, and inform similar efforts being undertaken in other places.

Glossary

Block pricing. A tariff structure, typical in residential electricity and water pricing, that connects the per-kWh charge to the amount electricity a customer uses. For example, the first 300 kWh in a month might be charged the lowest rate, the next 150 kWh a somewhat higher rate, and so on. The size of the pricing blocks and degree of price increase with each block can vary considerably across utilities.

Demand charges. A monthly fee, often charged to large-scale commercial and industrial customers, that is tied its greatest 15-minute demand over the previous year.

Down reserves. Ready, easily scalable generation capacity that can rapidly *decrease* to meet falling demand for power. Both up and down reserves are required to keep a power system in perfect continuous balance.

Efficient bypass. A situation where a customer chooses to bypass the grid and utility because the cost of self supply is less than the incremental cost to the utility of supplying the customer.

Feed-in tariffs. Contract prices (typically fixed) granted to independent producers of renewable energy that "feed" power into the grid.

Heat rate. The amount of energy used by a generator to make one kilowatt-hour of electricity. It is a standard measure of efficiency, and it can vary across generators, or for any particular generator depending the share of capacity in use.

Inefficient bypass. A situation where a customer chooses to bypass the grid and utility and generate their own electricity, even though the incremental cost to the utility of serving that customer is less than the cost of the customer generating their own electricity.

Interval Meters. Interval meters are devices that that can keep track of electricity during different times of the day, but do not necessarily involve two-way communication with the utility like a smart meter. Interval meters can even be mechanical devices with a clock that simply record electricity use separately for different times of day.

Levelized cost. The minimum average real price needed to for an electricity generation investment to break even. Technically, it is the sum of lifetime cost of generation from a particular source of electricity divided by the sum of electricity generated by that source, with both costs and electricity discounted to the present.

Marginal cost. The incremental cost of last kilowatt generated at each moment. Standard economics and engineering centers on the mathematics that indicate efficiency is achieved when marginal cost equals price (marginal willingness to pay).

Microgrid. A small-scale power grid that can operate independently, in whole or in part, from a larger grid to which it may or may not be connected. If a microgrid can operate both independently and in conjunction with a larger grid, it can increase redundancy and reliability.

Missing Money. An informal term, increasingly popular in energy circles, for situations where marginal cost pricing does not collect enough revenue to cover the full capital and fuel costs of all generating facilities, eventually leading to inefficient bankruptcy.

Natural monopoly. A market in which the least cost way to produce a good is from a single entity. In the absence of regulation, natural monopolies have a strong incentive to keep prices much higher than socially efficient and competing firms are naturally deterred from entering, since the already-existing firm could immediately undercut them. Most utilities – especially the distribution component – are considered natural monopolies.

Net present value. A standard financial measure that equals the sum of all current and future benefits minus costs, all converted into present values using a discount rate. If the net present value of an investment opportunity is positive, it is normally considered a worthy investment; if the net present value is negative, it is normally considered an unworthy investment.

Option value. The value of preserving the option of buying or using an asset, even if use of the asset is not immediately expected or unlikely. Sometimes option values refer to the value of waiting until the future to make an investment decision.

Performance-based regulation. Performance-based regulation connects the utility's allowable revenue recovery to specific performance metrics, such as costs, reliability, amount of clean energy, or other measures of service quality. For example, if the utility were to find creative ways of reducing costs, a performance metric might allow the utility to keep a share of the reduced profits as earnings, which might add to employee bonuses passed on to shareholders in the form of higher dividends.

Rate case. A scheduled evaluation by the Public Utilities Commission of the prices that regulated utilities charge customers.

Rate-of-return regulation. When regulated utilities make investments in generating capacity, transmission and distribution lines, transformers, or kinds of capital, they normally need approval from Public Utilities Commission. If the investment is approved, then the utility is allowed to recover revenue (i.e., adjust rates) sufficient to earn a "fair rate of return" equal to the market cost of capital. Presumably such investments have value, and may save costs, replace old capital, allow the utility to expand coverage to satisfy growing demand. Approval of proposed investments ought to hinge on whether the utility can demonstrate that the investment is prudent and necessary.

A potential problem with rate-of-return regulation is that the utility's profit is not explicitly tied to the wisdom or social value of the investment. And if the rate of return attached to the investment is set too high or too low, then the utility will have a clear profit motive to over-invest in capital if the rate is set too high (the usual case), or to bypass worthwhile investment if the rate is set too low. In recent decades, the incentive to over-invest may have become stronger, because allowed rates of return have not fallen as much as market rates have. (See this **link**)

Revenue decoupling. A regulatory tool inspired by those interested in conservation, efficiency and distributed generation that "decouples" a regulated utilities allowed revenue from the quantity it sells. Thus, utilities are allowed to raise prices if they sell less quantity than projected and must lower prices if they sell more quantity than projected. Note that the revenue connected to revenue decoupling rules typically targets revenue *net* of fuel and purchased power costs, *not* total revenue.

Stranded assets. Assets that become obsolete before being fully depreciated and must be written off as a loss.

Smart Meters. Electronic devices that record consumption of electricity on intervals of one hour or less and communicate this information back to the utility for monitoring and billing. Such meters provide the utility with much more information about what is happening on the grid and can therefore improvement management and targeted problem solving. They also reduce or eliminate the need and cost of in-person meter reading.

System Lambda. A technical measure of marginal cost—the incremental cost of increasing power by a single kWh---that comes from power system management software that is designed to optimally balance supply and demand in the grid.

Up reserves. Ready, easily scalable generation capacity that can rapidly *increase* to meet rising demand for power. Both up and down reserves are required to keep a power system in perfect continuous balance.

Appendix A. Preliminary Results on the Value of RTP in High-Renewable Systems by Imelda, Matthias Fripp and Michael Roberts.

The larger study will consider a total of 864 scenarios that span the following sets of assumptions. Here we report some results for 36 scenarios, indicated in boldface:

Inter-hour demand flexibility (3):	**Optimistic, Middling, Pessimistic**
Cost assumptions (2):	**HECO PSIP assumptions for 2016 & 2045**
Overall electricity demand (4):	**0.1**, 0.5, 0.9, 2.0
Electric vehicle share (3):	0.5%, **50%**, 100%
Generation mix (3):	**Fossil, 100% Renewable, Unconstrained**
Baseline load profile (2):	**Projected 2045**, Actual 2007.
Flat or Variable (MC) prices (2)	

Table A1. Summary of cost assumptions in preliminary study on real time pricing.

Category	Description	Capital cost ($/MW) 2017	Capital cost ($/MW) 2045	Unit cost 2016	Unit cost 2045	Op. & Maint. ($/MW/Yr.)
New power generators						
	CC_152	1,653,242	1,415,952			17,452
	CentralTrackingPV	2,856,257	1,680,388			22,970
	DistPV	3,650,295	1,511,097			-
	IC_Barge	1,323,183	1,323,328			34,214
	IC_MCBH	3,162,083	2,855,884			33,844
	IC_Schofield	2,481,336	2,241,312			33,844
	OffshoreWind	6,205,598	3,882,934			96,710
	OnshoreWind	2,459,329	1,986,498			27,400
	Pumped Hydro	3,033,333	3,033,333			
Storage						
	Battery	484,283	146,639			
	Hydrogren electrolyzer	1,596,797	697,014			
	Hydrogen fuel cell	990,562	528,787			
	Hydrogen liquifier	42,997	42,997			
Inputs for fossil power plants						
	Biodiesel ($/gal)			30.37	48.68	
	Coal ($/mt)			2.74	3.60	
	Diesel ($/gal)			10.48	32.50	
	LNG bulk ($/MMBTU)			6.26	22.01	
	LNG container ($/MMBTU)			10.52	14.38	
	LSFO ($/MMBTU)			7.95	29.56	
	Pellet-Biomass ($/tonne)			14.00	14.00	

Note: Cost assumptions are derived from Hawaiian Electric Company's Power Supply and Improvement Plan from December 2016. See `https://www.hawaiianelectric.com/about-us/our-vision`.

Table A2. Demand flexibility assumptions.

		Demand Flexibility Scenario		
	σ	Optimistic	Moderate	Pessimistic
Potentially-shiftable load (A/C, water heating, water pumping)				
Highly Flexible	10	67%	33%	15%
Somewhat Flexible	1	5%	5%	5%
Highly Inflexible	0.1	28%	62%	80%
Share of other load				
Highly Flexible	10	15%	8%	0%
Somewhat Flexible	1	5%	5%	5%
Highly Inflexible	0.1	80%	88%	95%

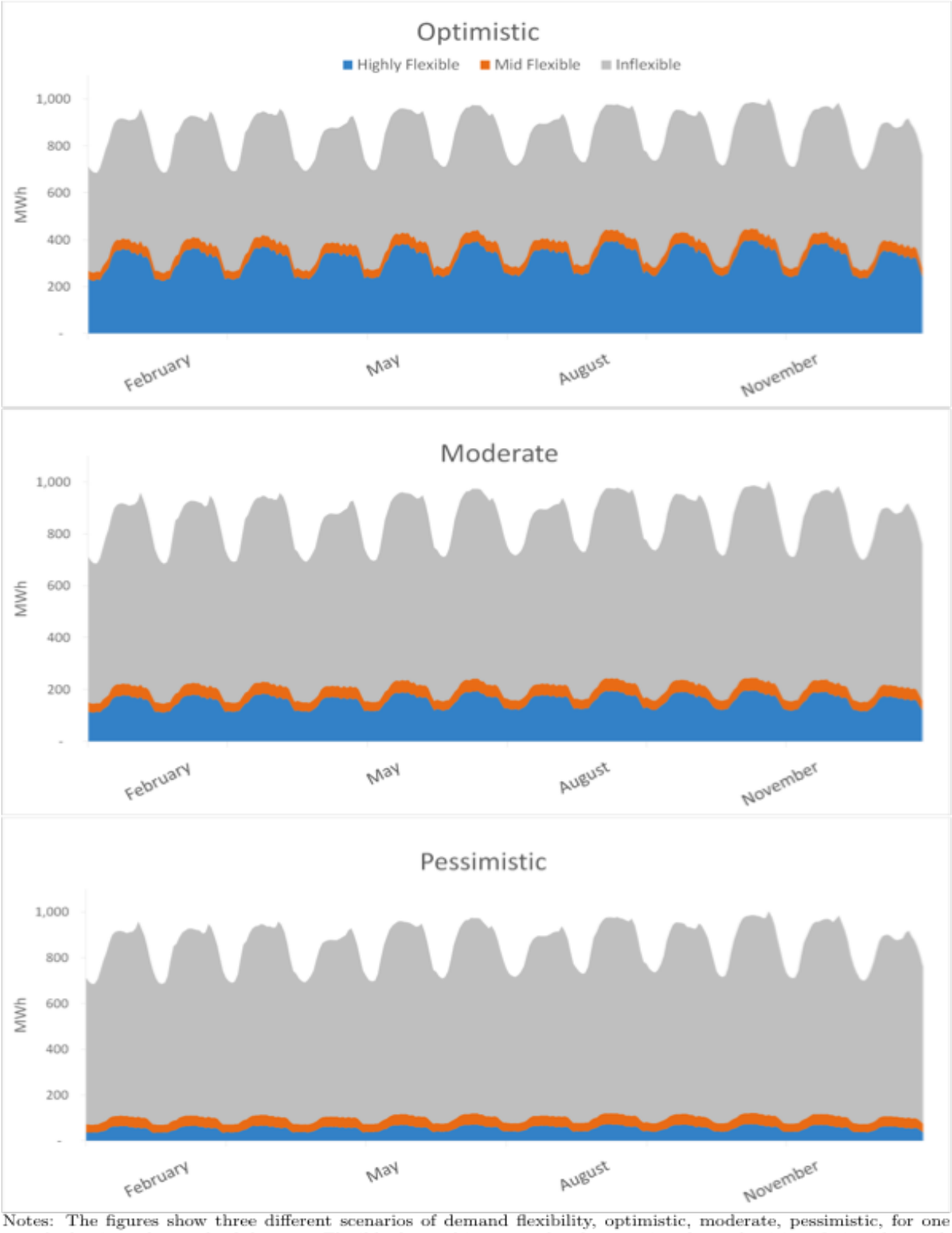
Notes: For each hour in each month, we allocate shares of potentially flexible load (estimated demand for A/C, water heating and water pumping) and all other load as indicated in the above table for each scenario. A graph of these scenarios is shown below. The parameter σ gives the inter-hour elasticity of substitution for each demand type.

Table A3. Preliminary results for real-time pricing study.

Policy Objective	Demand Flexibility	Cost Assumption	Pricing	Percent Renewable	Price ($/MWh)	Mean Q (MWh/hr.)	SD of Price ($/MWh)	Δ CS ($ Mil.)	Δ PS ($ Mil.)	Δ TS ($ Mil)
Fossil	Optimistic	Current	Flat	4.98%	180.05	859.14	-	0	0	0
Fossil	Optimistic	Current	Dynamic	4.93%	164.09	869.05	7.39	115.63	-93.42	22.21
Fossil	Optimistic	Future	Flat	4.94%	169.78	865.46	-	77.68	-59.83	17.85
Fossil	Optimistic	Future	Dynamic	4.93%	164.13	868.87	8.44	114.81	-84.86	29.96
Fossil	Moderate	Current	Flat	4.98%	180.10	859.11	-	0	0	0
Fossil	Moderate	Current	Dynamic	4.93%	164.00	869.31	13.74	117.86	-95.79	22.07
Fossil	Moderate	Future	Flat	4.94%	169.80	865.45	-	77.83	-61.44	16.39
Fossil	Moderate	Future	Dynamic	4.97%	160.78	871.71	7.55	139.43	-110.37	29.06
Fossil	Pessimistic	Current	Flat	4.98%	179.64	859.39	-	0	0	0
Fossil	Pessimistic	Current	Dynamic	4.93%	162.60	869.96	2.17	128.82	-106.95	21.87
Fossil	Pessimistic	Future	Flat	4.94%	169.55	865.61	-	76.28	-59.9	16.38
Fossil	Pessimistic	Future	Dynamic	4.96%	158.20	871.73	11.07	157.68	-129.55	28.13
RPS	Optimistic	Current	Flat	100%	196.20	849.87	-	-120.7	62.97	-57.73
RPS	Optimistic	Current	Dynamic	100%	149.37	985.45	140.63	224.72	-11.33	213.39
RPS	Optimistic	Future	Flat	100%	98.89	923.05	0.00	635.66	-157.96	477.71
RPS	Optimistic	Future	Dynamic	100%	85.66	1,055.57	88.02	753.33	-161.7	591.64
RPS	Moderate	Current	Flat	100%	196.20	849.87	-	-120.36	62.67	-57.69
RPS	Moderate	Current	Dynamic	100%	167.78	969.46	164.91	106.75	34.85	141.61
RPS	Moderate	Future	Flat	100%	98.89	923.05	-	636.01	-158.26	477.75
RPS	Moderate	Future	Dynamic	100%	89.59	1,031.26	85.71	723.72	-162.24	561.48
RPS	Pessimistic	Current	Flat	100%	196.20	849.87	-	-123.85	66.17	-57.68
RPS	Pessimistic	Current	Dynamic	100%	177.83	948.64	160.29	18.09	63.29	81.38
RPS	Pessimistic	Future	Flat	100%	98.89	923.05	-	632.52	-154.76	477.76
RPS	Pessimistic	Future	Dynamic	100%	91.89	1,005.64	78.83	700.66	-161.07	539.59
Unconst	Optimistic	Current	Flat	61.39%	146.15	881.51	-	259.08	37.53	296.61
Unconst	Optimistic	Current	Dynamic	73.26%	119.53	939.83	59.07	447.63	-31	416.64
Unconst	Optimistic	Future	Flat	87.60%	96.33	925.84	-	656.92	-83.37	573.56
Unconst	Optimistic	Future	Dynamic	88.15%	79.16	1,008.06	65.65	784.53	-121.35	663.18
Unconst	Moderate	Current	Flat	62.09%	148.91	879.51	-	238.05	59.58	297.63
Unconst	Moderate	Current	Dynamic	71.67%	130.28	930.14	73.64	363.02	38.13	401.15
Unconst	Moderate	Future	Flat	87.60%	96.33	925.84	0.00	657.26	-83.67	573.59
Unconst	Moderate	Future	Dynamic	87.73%	85.17	994.87	54.04	735.11	-103.08	632.03
Unconst	Pessimistic	Current	Flat	60.48%	146.27	881.42	-	255.05	42.5	297.55
Unconst	Pessimistic	Current	Dynamic	65.72%	124.81	919.89	56.84	413.39	-37.82	375.56
Unconst	Pessimistic	Future	Flat	87.58%	96.34	925.82	0.00	653.52	-80.05	573.46
Unconst	Pessimistic	Future	Dynamic	88.70%	89.35	979.83	60.52	712.08	-99.5	612.59

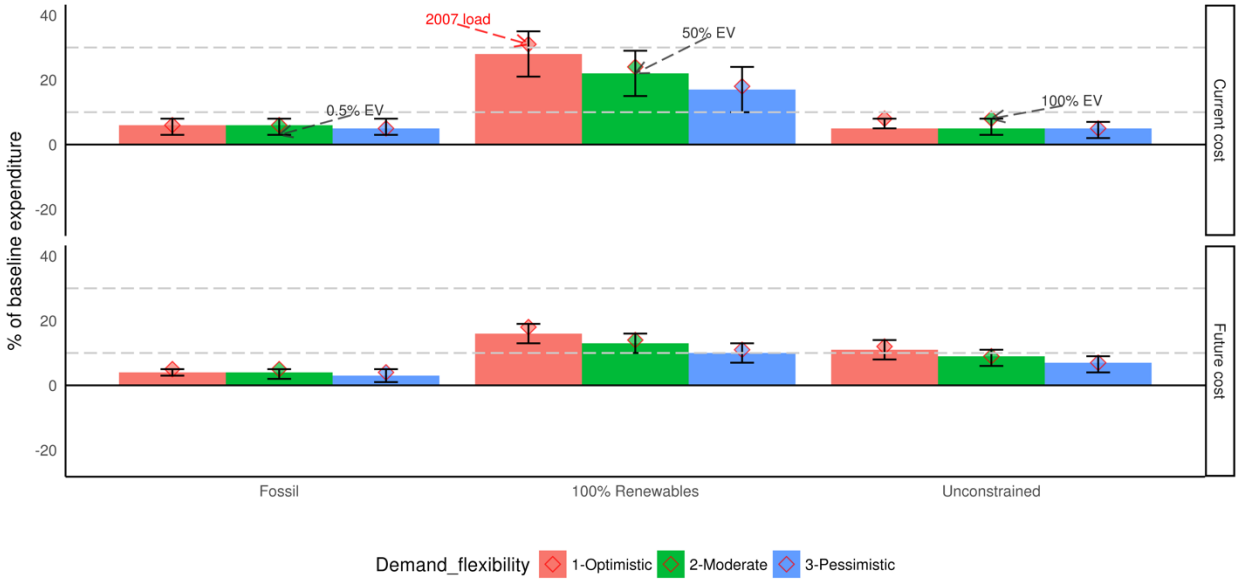
Notes: Models were solved for a range of assumptions, as indicated in boldface above. The first four columns summarize scenarios defining assumptions of each model. All scenarios assume 50% of the vehicle fleet is electric by 2045. The first column (Policy Objective) indicates exogenous constraints determined by policy: The *Fossil* scenario restricts any new installation of renewable energy, but is otherwise least cost; the *RPS* scenario forces use of 100\% renewable generation; and the *Unconstrained* scenario is least cost without any constraints on the mix of power plants. The second column indicates the degree of demand flexibility, as detailed in Table A2. The third column indicates whether current costs from the Power Supply and Improvement Plan are used, or the present value of future costs projected for 2045. The fourth column indicates whether residential prices are flat or dynamic (time-varying, equal to marginal cost). Price and quantity are summarized in the next three columns. The last four columns report the change in consumer surplus, producer surplus and total surplus relative to a base case of a fossil system with current costs and flat pricing. Note that this analysis does not include grid costs or the utility's operation costs, only costs reported Table A1.

Figure A2. Demand flexibility scenarios in real-time pricing study.



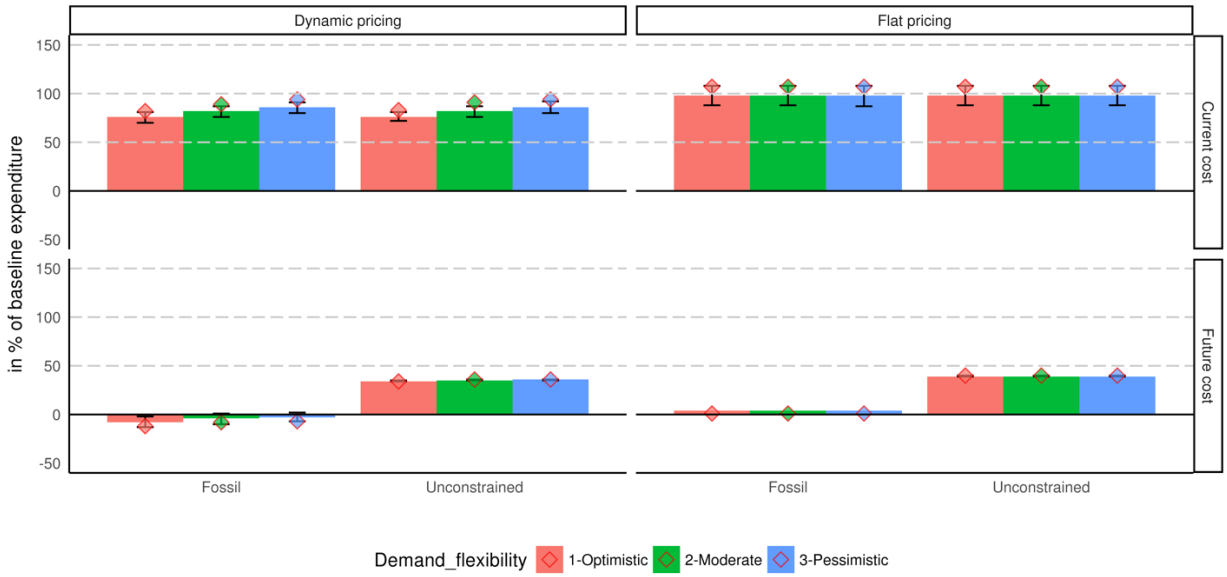
Notes: The figures show three different scenarios of demand flexibility, optimistic, moderate, pessimistic, for one sample day in each month of the year. Flexible demand is assumed to have an interhour elasticity of 10 within each day; Mid Flexible demand has an inter-hour elasticity of 1, and Inflexible demand has an inter-hour elasticity of 0.1. All demand types have an overall demand elasticity of 0.1.

Figure A3. Estimated net benefit of real-time pricing relative to flat pricing as a percent of baseline expenditure on electricity.



Notes: The graph reports the total benefit to consumers of a fully optimized system built around real-time, marginal-cost pricing in comparison to a system optimized around flat pricing. The value of real-time pricing varies with the inter-hour flexibility of demand, as indicated by the different colored bars. The left three bars show the value of real-time pricing with an optimized fossil system that includes only currently installed renewables. The middle three bars show the value with a 100% renewable system. The right three bars show the value in a system that is least cost (the generation mix is unconstrained). The top row shows the values under current costs (2016), and the bottom row shows the values under projected future costs (2045). The bars and whiskers show how values change with different levels of electric vehicle use (0.5% or 100% instead of 50%), and the diamonds show how values change with actual 2007 loads instead of projected 2045 loads.

Figure A4. Estimated cost of a 100 percent renewable system relative to a fossil system and unconstrained (least cost) system.



Notes: The graph reports the total cost of a fully optimized 100% renewable system built around real-time, marginal-cost pricing in comparison to a system optimized around flat pricing, with differences reported as a percent of baseline expenditure (flat pricing of a fossil system under current prices). The cost of the 100% renewable system is notably less with real-time pricing (left two columns) than with flat pricing (right two columns), and under future 2045 costs (bottom row) than under current 2016 costs (top row). Inter-hour flexibility of demand, as indicated by the different colored bars, reduces the cost of renewables in a dynamic pricing environment but makes no difference in a flat pricing environment. The left column in each pair (columns 1 and 3) shows the cost of a 100% renewable system relative to a fossil system, and the right column in each pair (columns 2 and 4) shows the cost of a 100% renewable system relative to a least-cost unconstrained system. The bars and whiskers show how values change with different levels of electric vehicle use (0.5% or 100% instead of 50%). The diamonds show how values change with actual 2007 demand instead of projected 2045 demand. Note that costs considered do not include distribution and operation costs of the utility, only generation capital and fuels, as summarized in Table A1. Also note that an unconstrained system includes a large share of renewables, especially under future cost scenarios with variable pricing (see Table A2).

Appendix B. Conference Agenda and Participants.

Governing Green Power: Realigning Institutions To Fit New Technologies

University of Hawaiʻi at Mānoa, March 28-30, 2017

Information Technology Center Conference Room

This conference brings together people who are exceptionally knowledgeable about the economics, engineering and policies that govern the electricity sector. Our aim is to have an open exchange of ideas about improving governance – rules, regulations and incentive mechanisms – in light of rapidly advancing renewable energy and computing technologies. We have developed an agenda and process to organize the issues and allow for rich but structured participation from everyone.

Conference Process:

All sessions (except I and IX) will have the following format:

1. Brief introduction by facilitator. (Makena Coffman, Meredith Fowlie or Dick Pratt)
2. Short Presentation (10 minutes or less).

   We have invited selected participants to provide a brief summary of key issues they see as most important for the particular session. The main goal of the presentation should be to frame the issues and raise questions to focus the group discussion. For presenters who wish to use slides, we encourage you to use no more than six.
3. Primary responders (7 minutes or less each).

   With context already provided, we ask that primary responders present their own views on the topic, perhaps adding to or presenting alternative viewpoints from the main presentation. We recommend no more than four slides for each primary responder.
4. Facilitated open dialogue (45+ minutes).

   All conferees will have an opportunity to either ask questions of the presenter and primary responders, or present their own views.
5. Wrap-up of main points (5 minutes or less).

   One person will be assigned to listen carefully and briefly summarize what they see as the most important points from the session.

Other important conference features:

- In addition to participation as presenters, primary responders and in open dialogue, everyone will be able to register real-time thoughts, reactions and opinions through their wifi-connected devices. We will be using MeetingSift (www.meetingsift.com) - the participant code will be provided. Note that entries are limited to 140 characters each so we welcome multiple "tweets" to record your full comment.

- The conference will be videotaped with an eye to excerpting portions for classes or the

conference website. Any public use of the videotape would be done only with permission of those taped.

- No media will be present at the conference to foster an open exchange on sometimes-sensitive issues. Information given to the media after the conference will share positions on issues and conference recommendations, but will not attribute these to individual conference participants.
- The conference website is: http://socialsciences.hawaii.edu/conference/govgreen/index.html. Post-conference documents will be available here.

Monday, March 27, 2017

6:00 - 8:00pm Welcome Reception - New Otani Kaimana Beach Hotel

Participants and family from outside of Hawai'i, conference sponsors, UH Deans of Social Science and Engineering, conference organizers.

Tuesday, March 28, 2017

8:00 – 9:00 Breakfast (IT Center Conference Room), Conference Participants

9:00 – 10:15 Session I: Welcome, Introductions, Conference Goals and Process

9:00 – 9:05 Dick Pratt: Welcome
9:05 – 9:20 Michael Roberts: Motivation and goals for the conference
9:20 – 9:30 Brief introductions by everyone (10 seconds or less)
9:30 – 9:40 Remarks from Governor Ige
9:45 – 9:55 Dick Pratt: Conference process and schedule
9:55 – 10:15 What each participant sees as the most important or interesting issue or issues (30 seconds or less per person)

10:15 - 10:30 Break

10:30 - 11:50 Session II: What are the Benefits if We "Get it Right" and the Consequences if We Don't?

Dynamic, marginal-cost pricing and open access to the grid can lower costs and help integrate renewables; without them, we could have grid defection, and spiraling costs for those who cannot defect.

Facilitator: Dick Pratt, *UH Mānoa Social Sciences International/Community Programs*
Presenter: Michael Roberts, *UH Mānoa Economics, Sea Grant, and UHERO*
Primary Responders: Duncan Callaway, *UC Berkeley Energy and Resources Group*
Maria Tome, *Hawai'i Public Utilities Commission*

Richard Barone, *Hawaiian Electric Company*
Severin Borenstein, *UC Berkeley Haas School of Business and Energy Institute*
Wrap-Up: Richard Newell, *Resources for the Future and Duke University*

12:00 - 1:20 Lunch (Sustainability Courtyard)

1:30 - 3:00 Session III: Current Institutions and Challenges with Intermittent Renewables

What currently works, what doesn't, and why? Wholesale markets have developed various mechanisms to ensure sufficient capacity and to mitigate market power. Some utilities have incentive mechanisms to better manage costs, but these can be compromised by revenue decoupling rules. Rate-of-return regulation dominates transmission and distribution investments, as well as vertically integrated utilities like Hawai'i's. Investment-based profit motives of utilities can conflict with more efficient solutions centered on demand-response. Transmission, distribution, generation, storage and demand response are not optimally balanced and integrated.

Facilitator: Meredith Fowlie, *UC Berkeley Economics and Haas Energy Institute*
Presenter: Matthias Fripp, *UH Mānoa Electrical Engineering and UHERO*
Primary Responders: Matthew White, *ISO New England*
Steven Puller, *Texas A&M University Economics*
Carl Freedman, *Haiku Design and Analysis*
Jay Griffin, *Hawaii Natural Energy Institute*
Wrap-up: (TBD)

3:00 - 3:20 Break

3:20 - 4:50 Session IV: Markets and Natural Monopolies: How has Technology Changed the Case for Regulation?

Natural monopoly in generation diminished decades ago, but market power still exists in transmission and distribution. To what extent have renewable energy and complementary technologies—batteries, smart meters and smart controllers—changed the degree and nature of natural monopoly, and thus the overarching case for regulation? If we look 5-10 years out, does natural monopoly vanish?

Facilitator: Makena Coffman*, UH Mānoa Urban and Regional Planning and UHERO*
Presenter: Severin Borenstein, *UC Berkeley Haas School of Business and Energy Institute*
Primary Responders: Richard Newell, *Resources for the Future and Duke University*
Nori Tarui, *UH Mānoa Economics and UHERO*
Jim Alberts, *Hawaiian Electric Company*
Stephen Holland, *UNC Greensboro Economics*
Terry Boston, *former CEO and President of PJM Interconnection*
Wrap-up: Marc Matsuura, *Hawaii Natural Energy Institute*

5:30 - 8:00 Dinner Reception at College Hill

Wednesday, March 29, 2017

8:00 - 8:30 Breakfast (IT Center Conference Room)

8:30 - 10:00 Session V: Institutional Changes in Response to Renewables: How are Technology and Institutions Co-Evolving?

How have institutions changed already as a result of renewables? What are the consequences of these changes? Have the changes worked as intended? What are the unintended consequences? What are the lessons learned and how should this shape the way we approach decision-making, energy policy, and regulation?

Facilitator: Dick Pratt, *UH Mānoa Social Sciences International/Community Programs*
Presenter: Terry Boston**,** *Former CEO and President of PJM Interconnection*
Primary Responders: James Bushnell, *UC Davis Economics*
Dave Parsons, *Hawai'i Public Utilities Commission*
Isaac Moriwake, *Earthjustice*
Mike Yamane, *Kaua'i Island Utility Cooperative*
Regina Finn, *Lucerna Partners*
Wrap-Up: Richard Wallsgrove, *Blue Planet Foundation*

10:00 - 10:20 Break

10:20 - 11:50 Session VI: New Ideas for Making Market-Based Electricity Systems Work Better with Renewable Energy

Electricity markets continue to evolve, in part to deal with issues of market power, and in part because renewable energy is causing greater price variability. What can be done to make these markets work more efficiently? How can generation be better integrated with transmission, distribution, and demand response?

Facilitator: Meredith Fowlie, *UC Berkeley Economics and Haas Energy Institute*
Presenter: Steven Puller, *Texas A&M University Economics*
Primary Responders: Regina Finn, *Lucerna Partners*
Matthew White, *ISO New England*
Alex Papalexopoulos, *ECCO International, Inc.*
Matthias Fripp, *UH Mānoa Electrical Engineering and UHERO*
Kyle Datta*, Ulupono Initiative*
Wrap-Up: Carl Bonham, *University of Hawai'i Economic Research Organization*

12:00 - 1:20 Lunch (Sustainability Courtyard)

1:30 - 3:00 Session VII: New Ideas for Utility Regulation with Renewable Energy

How can incentives be improved and what metrics ought to be used to measure success? Some propose performance contracts with utilities, and these exist for certain aspects. Are alternative organizational structures, like government municipalities or cooperatives, any better? Are market-oriented solutions possible at the distribution level or for smaller grids like Hawai'i's? If so, how? How can efficient real-time pricing of retail-level electricity be incentivized and regulated?

Facilitator: Makena Coffman*, UH Mānoa Urban and Regional Planning and UHERO*
Presenter: Alex Papalexopoulos, *ECCO International, Inc.*
Primary Responders: Meredith Fowlie, *UC Berkeley Economics and Haas Energy Institute*
Michael Roberts, *UH Mānoa Economics, Sea Grant, and UHERO*
Duncan Callaway, *UC Berkeley Energy and Resources Group*
Mark Duda, *Hawaii PV Coalition*
Dean Nishina, *Hawai'i Division of Consumer Advocacy*
Terry Surles, *Hawai'i State Energy Office*
Wrap-Up: Rene Kamita, *Hawai'i Division of Consumer Advocacy*

3:00 - 3:20 Break

3:20 - 4:50 Session VIII: Transitioning to a Fairer and More Efficient System: Is there a QWERTY problem?

Who gains and who loses if we transition to Utility 2.0? How are interests changing and evolving (e.g., utilities, customers, demand-response aggregators, ISOs, clean energy and storage companies)? Can these interests coalesce around a transition to fairer and more efficient governance systems? Can we anticipate where the conflicts will occur and develop strategies for reconciling differences?

Facilitator: Dick Pratt, *UH Mānoa Social Sciences International/Community Programs*
Presenter: Carl Freedman, *Haiku Design and Analysis*
Primary Responders: Mina Morita, *Energy Dynamics*
Katrina Jessoe, *UC Davis Economics*
Beia Spiller, *Environmental Defense Fund*
Douglas Codiga, *Schlack Ito*
Scott Seu, *Hawaiian Electric Company*
Wrap-Up: Mark Glick, *Hawaii Natural Energy Institute*

No Wednesday evening activities scheduled – on your own.

Thursday, March 30, 2017

8:00 - 9:00 Breakfast (IT Center Conference Room)

9:00 – 11:00 Session IX: Summary and Next Steps

Here we will provide a handout that summarizes key points pulled out from conference sessions. This will include policy recommendations, inclusive of critical counterpoints. We will elicit feedback to the summary. We will then turn to a discussion of where we go from here. What are the critical questions that require theoretical or empirical answers and how should academic researchers go about answering them? What should policymakers do and when should they do it?

Conference survey using MeetingSift.

Appendix C. Post-Conference Survey of Participants.

Survey of Conference Experience

Note: If responses do not add up to 100% it is because some respondents did not answer.

1. Type of organization you represent:

(1) University or research institute **(37.5%)**
(2) Government entity **(12.5%)**
(3) Utility **(12.5%)**
(4) Private for-profit sector **(20.8%)**
(5) Private not-for-profit sector **(12.5%)**
(6) Other **(4.1%)**

2. Overall, what do you think of the quality of the <u>content</u> presented and discussed during the conference? (Circle one)

Excellent **(75%)** *Good* **(25%)** *Fair* **(0%)** *Poor* **(0%)**

3. How much do you feel you learned? (Circle one)

A great deal **(54.2%)** *A fair amount* **(41.7%)** *A little* **(4.1%)** *Not much at all* **(0%)**

4. Overall, what do you think of the quality of the <u>process</u> used by the conference? (Circle one)

Excellent **(75%)** *Good* **(25%)** *Fair* **(0%)** *Poor* **(0%)**

5. What worked best for you?

<u>Comments:</u>

- Hearing perspective from different areas, even when potentially inapplicable in HI, helped to broaden range of thinking.

- Follow up discussions at reception and lunches were also very helpful. Panels were by and large extremely informative and robust. "Safe speech" to discuss policy matters was key
- The dialogue/conversation portion. Point/counterpoint/clarifications very instructive.
- Short presentations followed by open dialogue allowed for real time exchange of ideas that could be leveraged in outside follow-up. Wonderful discussion and conversation.
- Conversations with large group. Exchange of ideas in real-time. Consider breaking into small groups for parts of the discussions.
- Collegial attitudes and facilitator's ability to have meaningful discussions without entrenchment. Might consider soliciting suggested response discussions to help identify areas of greatest interest among participants.
- Summary and discussion on next steps.
- Stimulating topics in an extreme environment with respect to energy policy and issues.
- Opportunities for networking.
- Diversity of participants including from outside Hawaiʻi, engineers, economists, attorneys even was so valuable! Everyone of us could contribute and learn from others. 2) Format was so much more productive in encouraging discussion and conversation, versus more formal panel discussions.
- and side conversations.
- Explorations of what works and what does not elsewhere - learning from others' experience and expertise.
- Format was very well done!
- "Conversational" style approach - excellent facilitation - mix of keeping people to time and allowing <u>everyone</u> to contribute.
- Open dialogue opportunity and collegiality.
- Great to have all different viewpoints (econ, engineers, utilities, etc). Loved the panel set-up - very interactive and gave everyone a voice.
- I really like the structure of the program using the presentations as a springboard to the discuss.
- The best parts on the conference for me were: 1) Lunchtime conversation with my session. IT was semi-structured but still very open conversation. We raised a lot of interesting questions and spoke about potential solutions. 2) When conversations ran in some concrete but controversial ideas --> fossil fuel capacity; grid defection; exit fees. 3) across areas of expertise.
- Hearing and interacting with Hawaiʻi and other practitioners. Conference ran smoothly. Well done.
- It was nice to have plenty of time for informal discussion.
- Lots of time for dialogue.
- Focused discussions in each session that included a mix of academic and industry experts.
- The back and forth conversation
- Allow enough time for debate and interactions between participants. There was a real conversation

6. What didn't work well for you?

Comments:

- It seemed conspicuous that renewable industry interests weren't included. Was that a conscious choice? We were discussing "about" them and their work, but not with them. I think I end up with the view that they should be more meaningfully included and engaged to further enrich discussion and exchange.
- Long presentations, shorten in the future.
- Not sure how this could be structured but as a practioner, it would have been great to have deeper dives - maybe on a few critical decision points - so that more concrete and specific recommendations could be made.
- Panel topics were different but also in some cases too similar. For next time, perhaps spend additional effort narrowing and sharpening the focus on various panels.
- There wasn't enough time to discuss and flesh out certain aspects of issues. This does lend itself to additional discussions in other forums.
- Screens too small for slides.
- Some discussion was a bit too open-ended. It might have been better - though so challenging - to have a facilitator guide discussion further.
- I would say it didn't work, but coming up with a good summary (of what's discussed and of the next steps) is challenging, depending on what the summary is supposed to accomplish. Is it just a summary? Or is it a policy recommendation?
- Nothing.
- Some panels seemed typically duplicative as things played out.
- Topics were vague and ambiguous which allow conversation to go all over the map (not always good). Heavy on economics/light on engineering operations.
- Some participants/presenters perhaps assumed too high a technical knowledge amongst the audience.
- Framing on tangential issues and overreliance on economists to drive discussion into a vacuum or without commensurate attention to relevant statues and rules.
- The session felt a little all over the place (that is, each session covered so many topics that it was hard to follow the thread sometimes). Having slides would have helped - sometimes people ramble too much so with no visual aides, it can be difficult to follow.
- Without data, broad conclusions seemed to be drawn about what might work and what might not. Good to conceptualize, not let's test our assumptions. The topic of fairness was on the program, but we did not.
- Some ideas for improvement: 1) The possibility of restructuring each session are an issue: engineering, economic with real world examples. This would maybe focus the discussion and allow people to work through controversial examples. 2) Maybe leave a session or two at the end and focus those on most-discussed and of interest topics.
- Some of the food (not a fan of wraps), but everything else was great. (Oh, and some of the microphones (lipstick) didn't work very well)).

- MeetingSift didn't work that well. I think the word cloud worked well. You might also try asking some specific questions to get consensus from the group.
- Perhaps a little more room to show some results from research papers. Renewables was a heavy focus.
- Long questions. Maybe a slightly big group.
- Some sessions needed more structure.

7. How differently do you see the opportunities and challenges of introducing higher levels of clean and renewable energy now as a result of this conference? (Circle one)

Very Differently	*Somewhat Differently*	*No Difference*
(0%)	**(87.5%)**	**(8.3%)**

Comment:

- Incremental increase in knowledge. Still brainstorming. Solutions not clearly emerging--lack of consensus
- Grid defection is the standout for me - though I fear it is red herring?
- (I learned) what I've thought as challenging issues are indeed challenging after talking with experts. In addition I learned a few more challenges that I knew only vaguely about.
- I am more optimistic that through this discussion and follow-up that we will have greater intellectually honest discussions of policy and regulation and "utility 2.0."
- We deal with real issues of integration on a daily basis.
- There are considerable value judgments inherent on achieving the lowest marginal cost of generation options and grid improvements to achieve policy objectives.
- More potential to incorporate renewables if we change the approach to looking at the entire energy bill and not just electricity.
- I started to think about grid defection and just how critical reliability is.
- Complex topic. Always continuing to learn.

- Interactions are more clearly identified.
- Mainly around exit fees

8. How much of an effect did the conference have on the way you think about the relationship between changing technologies and existing institutions? (Circle one)

Strong Effect	*Moderate Effect*	*No Effect*
(29.2%)	**(58.3%)**	**(0%)**

Comment:

- Extremely helpful to have perspective of non-Hawai‘i advanced jurisdictions.
- Conference emphasized my current thinking about the relationship and the dynamic nature of that relationship.
- I would have liked even more discussion on the topic of real options/steering investments in the face of changing technology costs.
- Very helpful to get me more aware of other models and experiences. Not all will be applicable but it sets the foundation for me that there are alternatives.
- Largely a <illegible> rather than a challenge.
- We should not always compare plans to today's policies and capabilities. The prices and capabilities will be different in 5 years, so we need to compare options to the future as well, or at least scenarios.

9. The focus of this conference on the relationship between changing technology and energy related institutions was selected to address a critical emerging issue. If in the future another conference dialogue focusing on critical emerging issues is held, what do you think its focus should be?

Comment:

- The focus of this conference on the relationship between changing technology and energy related institutions was selected to address a critical emerging issue. If in the future another conference dialogue focusing on critical emerging issues is held, what do you think its focus should be?
- same
- The speed of change and its impact on reliability and robustness of the electric system.

- I think further refinement of the same topic would be great (see comment above!)
- Similar themes would be great, but perhaps more focus on debates about particular issues where expert's opinions differ? (E.g. implementing RTP and what to do with fixed charges, market design for enhancing DR…)
- This is Hawaiʻi-specific, but it critical that we grow our economy. How do you attract investment? A shrinking economy or one too reliant on tourism and government is not sustainable. Our discussion in this conference is heavily impacted by being in a declining load situation.
- How to decide on a DER <illegible> market and hard to get from today to the future
- More technical discussions on implementing new technologies - regulatory rule changes, communications systems, coordination mechanisms, optimization techniques, and results/outcomes in practice.
- Should focus more on Hawaiʻi issues.
- Turning concepts into reality - how to implement.
- Worthwhile to focus on some specific areas the group is willing to address in greater detail - i.e. work groups
- Personally, I'd like to weave in more about customers and their engagement. I always remember a statement from a ___ class I had at GE. "100% of all changes ah da good technical solution and 98% of all failed changes had a good technical solution." Lastly thinking about priorities so we can focus on implementation.
- Perhaps the two or three main challenges in Hawaiʻi: e.g. implementation of dynamic pricing and building reliability.
- More focus on the transition steps. We did some, but could do more. That's a real change that needs political/logistical/economic planning.
- Perhaps some more focused discussions on specific topics determined by consultation with Hawaiʻi electric sector stakeholders - commission, utilities, etc.
- carbon policy
- Development of markets

Mahalo!

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