September 26, 2005

Mr. Carlito Caliboso, Chairman
Hawaii Public Utility Commission
Department of Budget and Finance
465 S. King Street #103
Honolulu, Hawaii 96813

Dear Commissioner Caliboso,

On behalf of the Rocky Mountain Institute, we are pleased to present our comments on the Proposals for Implementing Renewable Portfolio Standards in Hawaii, as set forth in Act 95, Session Laws of Hawaii 2004.

We are providing comments on paragraphs 106, 121, and 172. Due to the nature of the questions posed, we have taken the liberty of combining our responses to certain issues in order to avoid repetition.

We would be pleased to present on the panels that will be held on October 3rd and 4th, 2005 in Honolulu. Overall, we believe our testimony would add valuable perspective in three areas:

- Paragraph 106: The overarching regulatory issues in designing the RPS and harmonization of utility incentives
- Paragraph 121: The candidate renewable resources and the appropriate methodologies for valuation of firm and intermittent resources
- Paragraph 172: Pros and Cons of alternative methodologies proposed and potential combinations of incentives to achieve efficiency

Best regards,

E. Kyle Datta

Kyle Datta
Senior Director

TESTIMONY OF THE ROCKY MOUNTAIN INSTITUTE ON THE PROPOSALS FOR IMPLEMENTING RENEWABLE PORTFOLIO STANDARDS IN HAWAII

Paragraph 106:

> ***Underlying Regulatory Issues in RPS Design for Hawaii***
> ***Appropriateness of Incentives, Fines, Penalties and Other IR Mechanisms***
> ***Implications of REC Trading Systems for Hawaii***
> ***Important Differences Between Investor Owned Utilities and Cooperatives***
> ***Integration with Utility Rate Design and IRP Processes***

1. Underlying Regulatory Issues on RPS Design for Hawaii

The objectives of Act 95 are clear: through the creation of targets for renewable power supply, improve the security of supply through the use of indigenous resources, reduce dependence on fossil fuels, enhance economic efficiency, lower the cost of power to consumers, and ensure the financial integrity of the utility does not suffer in the process. While the legislative objectives for Act 95 are straightforward, the regulatory issues that must ultimately be addressed are far more complex.

The regulatory issues that must be addressed in order to achieve these objectives can be boiled down to the following:

- What is a reasonable price for the utility to pay for the long run hedge on fossil fuel provided by firm, intermittent, or distributed renewable power sources?

- Which regulatory structures are required to provide incentives to Hawaii's investor owned utilities to actively manage the fuel prices for the benefit of consumers?

- How can the regulations governing the purchase of renewable power be structured to ensure that Hawaii's ratepayers enjoy the benefits of lower cost renewable power regardless of who builds the renewable power plant?

- How can we ensure that the utility's financial incentives are harmonized with the course of action that is least-costly to society, thereby ensuring both flexibility and economic efficiency?

Throughout our testimony, RMI will be returning to these issues, but let us start with some fundamental problems in the current regulatory structure that must be solved:

- **Ratepayers bear the cost but do not receive the hedging benefits of renewable resources built by independent developers**. Since the utility pays for renewable power from IPPs based on avoided costs -- which are derived from the actual price of fuel delivered to each of the state's utilities -- ratepayers do not receive the financial benefit of the hedge, but do bear the cost. Ratepayers would only receive the benefit of lower costs if the utility built the renewable power plant or the utility was able to negotiate a fixed cost contract. However, the utility is often unable to negotiate such contracts or purchase a contract to hedge the fuel price, without some assurance they will be found prudent by the PUC. To resolve this critical problem, the PUC will need to adopt an algorithm for determining what fixed price for firm, intermittent and distributed renewable power would be prudent.

- **Investor Owned Utilities (IOUs) have no incentive to reduce fuel costs to ratepayers.** Fuel costs and purchased power costs are entirely passed through to the ratepayers, who bear all the costs and risks of continued fossil fuel risk. Since there is no retail and only limited wholesale competition for power in Hawaii, and net metering is limited to a small fraction of total load, there is no competitive benefit to incurring financial risk (from hedging) or operational risk (from higher renewable penetrations) to lower fuel costs to ratepayers.

- **IOUs have a disincentive to adopt IPP built renewables if it displaces their own fossil fuel plants, and no penalty for failure to achieve the RPS targets.** Since utilities earn a rate of return on the capital used for investments in their own generation facilities (typically fossil fuel plants), they have a disincentive to allow independently produced renewable power to enter the market place, even if they are the least-cost solution. IPPs have historically had a difficult time getting PPAs from the investor owned utilities. The lack of penalty to dissuade such action only creates the license for the potential behavior.

- **The current definition of a "cost effective" standard to which renewables will be compared is based on a definition of avoided costs that does not include consideration of the risk and volatility of fossil fuels, nor does it account for intermittent renewables contribution to reliability**. Fossil fuels are inherently risky and volatile, and the financial markets define the premium that must be paid to lower that risk. Intermittent renewables do have a contribution to reliability, but may also impose additional operational costs. Both considerations should be incorporated into the definition of avoided costs. At a minimum, avoided costs should include valuation of fossil fuel risks in order to correctly define whether renewables are cost effective. Both fossil fuel risk premiums and intermittent renewable reliability can be quantitatively valued.

- **There is no mechanism to address the equity concerns if one of HEI subsidiaries ratepayers is bearing the costs to meet the RPS standards while other HEI subsidiaries enjoy the benefits.** Given the difficulty in siting renewable power facilities in the primary load center, Oahu, it is highly probable that MECO and HELCO ratepayers will bear the costs of meeting the RPS standards.

2. Appropriateness of Incentives, Fines, Penalties and Other IR Mechanisms

In general, RMI supports the overall findings of the Economists Incorporated (EI) that some degree of liberalization of the retail and wholesale power markets is an important consideration in defining an RPS. RMI acknowledges EI's findings that Renewable Energy Credits (RECs) have been adopted in states that are interconnected in order to create a deeper, more competitive market. In this regard, Hawaii is neither deregulated, nor are the utility systems interconnected with each other. We concur with the approach that the RPS regulations must be appropriate for Hawaii's situation.

RMI agrees with EI's finding that "an important component of RPS implementation is the definition of credible targets and strict enforcement".[1] RMI notes that over half of the states implementing RPS have created some penalties for non-compliance.

RMI agrees that safeguard provisions for events beyond the utilities' control are a reasonable aspect of an RPS but, unlike the Texas RPS Statute, which clearly defines the conditions that are beyond a utilities control, Act 95 is vague. The Commission may wish to clarify this by adopting language similar to Texas, as in:

> An electric utility company is responsible for conducting sufficient advance planning to acquire its percent of net electricity sales. Events or circumstances that are outside of a party's reasonable control may include weather-related damage, mechanical failure or failure of the renewable power provider to meet its contractual obligations to electric utility company, strikes, lockouts, actions of governmental authority that adversely effect the generation, transmission, or distribution of renewable energy from an eligible resource under contract to a electric utility purchaser.

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[1] Economists Incorporated, *Proposals for Implementing Renewable Portfolio Standards in Hawaii",* July 26,2005, at paragraph 103.

RMI refers the commission to its prior testimony on November 14th, 2004 in this docket, regarding seven design principles that are ubiquitous and fundamental to RPS success.[2] We support the proposal that prudently incurred RPS compliance costs should be recoverable to maintain a successful RPS policy.[3] Wiser, et al, have written that in order to maintain an RPS that is nondiscriminatory[4] and consistent with market structure[5], prudently incurred RPS compliance costs should be recovered from end-use electricity customers. It is important that there is clear and unambiguous guidance from electric utility regulators on what the definition of "prudently incurred costs" is, as well as whether other transmission-related costs can also be recovered through ratepayers.

3. Implications of REC Trading Systems for Hawaii

Renewable Energy Credits (RECs) are a mechanism to provide flexibility for utilities or load serving entities to meet the RPS standards. In applying this concept to Hawaii, we must consider the unintended consequences of how this approach is implemented.

First, if RECs of any sort are adopted, they should be the property rights of the entity producing the renewable power. The guiding principles should be that any entity that produces renewable energy will receive credit for each kWh of renewable energy generated, and any person generating renewable energy may sell their RECs to any renewable energy credit-trading program (either intrastate or interstate). In other words, renewable producers should own the rights and should be allowed to sell them to the market that gives them the best price.

If Hawaii's utilities are allowed to buy interstate RECs to meet the RPS, what will be the outcome? The economic evaluations of Hawaii's renewable potential conducted by DBEDT, Black and Vetch, and Bollemier and Associates all recognize that because of Hawaii's high factor costs, shipping costs, and comparatively small scale, the costs of developing renewables is nearly 50-100% higher, on a levelized cent per kWh basis than on the US mainland. Therefore, the least-cost approach will almost always be to purchase RECs from renewable power producers on the mainland. While this may be beneficial from an economic efficiency perspective, it does not improve Hawaii's energy security or provide the opportunity for lower costs to ratepayers.

What if an intrastate credit scheme were developed? Some, but not all REC schemes require the RECs to be produced from within the relevant power market. The advantage of an intrastate scheme is that it would allow the state's utilities to purchase

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2 R. Wiser, K. Porter, R. Grace, C. Kappel, *Evaluating State Renewable Portfolio Standards: A Focus on Geothermal Energy,* 03 September 2003, Available at: https://www.geocollaborative.org/publications/RPS_Summary.pdf

3 Wiser et al., *supra* note 1, at 47-48.

4 "A nondiscriminatory RPS will be applied fairly, consistently, and proportionally to all market participants and customers." *Id.* at 47.

5 "A RPS that is consistent with market structure will be consistent with and complement the structure of a state's electricity market, whether regulated or restructured." *Id* at 48.

credits from producers on other islands, if they were unable to site enough renewable power to meet their requirements from within their own service territory. For example, it is quite possible for KIUC to develop renewable energy within their service territory in excess of their RPS requirements in order to lower fuel costs and, thus, total rates, and for the HEI companies, particularly HECO, to have insufficient renewable power to meet the RPS targets. The same situation could occur between HEI utility subsidiaries.

However, the problem with an intrastate scheme is that the market is thin, with few buyers and sellers. This circumstance could occur if factors prevent the timely siting of in-state renewables, or if the in-state RECs were sold to other states. Hence, there is a danger of high prices for credits in the absence of a defined pricecap. The defined price cap for a REC should be set so that the combination of REC and power payments for renewable power are no more than avoided costs (assuming avoided costs are correctly defined). Further, REC markets will be functional only if there is a penalty for failure to comply with the RPS target, otherwise there would be no buyers. The penalties, as we shall discuss in the next section, must be set high enough to dissuade non-compliance behavior. In addition, safeguards must be developed to address circumstances beyond the utilities' control. Thus, the intrastate trading scheme would be similar to the one adopted by Texas. While an intrastate REC scheme may provide flexibility and hence enhance economic efficiency, it might well work against at least some of the goals of the RPS. Ultimately it is RMI's position that in a situation like Hawaii's today, a well functioning RPS should not require a trading scheme.

4. Important Differences Between IOUs and Cooperatives

The difference between the management incentives for adoption of renewables between IOUs and cooperatives is profound. IOUs, such as HECO, MECO and HELCO, must ultimately be concerned with impacts to shareholder value. By contrast, since the ratepayers are the shareholders of cooperatives, a cooperative such as KIUC seeks to lower the total costs to its members, while maintaining its own financial integrity. As a cooperative, KIUC already has a strong incentive to minimize the future uncertainty of rates caused by the volatility of fossil fuels. The difference between KIUC and the HEI companies is clearly evident in the goals of their ongoing IRP processes.

This difference in the alignment of the utilities toward the least-cost approach means that many of the concerns addressed in RMI's testimony do not apply to KIUC. Therefore, we have explicitly noted when problems arose due to the ownership structure of the utility.

5. Integration with Utility Rate Design and the IRP Process

The setting and design of rates are extremely important and "one of the regulator's most effective means by which to achieve desired policy objectives," because no matter how rates are set, they will offer some type of incentives.[6] The key is to use rate design to encourage efficient electricity use and to adhere to the NARUC principle that the most profitable course of action for the utility is the least-cost path for society. With this in mind, the integration of RPS with utility rate design is equally important.

Renewable power acts as a hedge on fossil fuel costs and can effectively lower total rates to consumers. As discussed below, the addition of renewables to the generation portfolio reduces the overall risk of that portfolio with respect to the volatility of the fossil fuel markets. Regulators have struggled with incorporating the concept of risk reduction vs. future market prices, as demonstrated in the regulatory and market debacle of the California Energy Crisis of 2000-2001.

Utilities under traditional rate regulation, such as those in Hawaii, pass their fuel costs to consumers, and thus have no incentive to take actions that would reduce these fuel costs. Further, since utilities earn a rate of return on the capital used for investments in their own generation facilities (typically fossil fuel plants), they have a disincentive to allow independently produced renewables to enter the market place, even if renewables are the least-cost solution.

Although the Integrated Resource Planning process is the mechanism for determining the most prudent mix of resources, this has not been used as an enforceable guide to utility actions within the State of Hawaii. Worse, the IRP process in Hawaii has been (and continues to be) poorly executed, *particularly* with respect to the assumptions made about future fossil fuel prices. Beyond that, interconnection costs for renewables are often overstated relative to fossil, and the evaluation process has been systematically skewed in favor of fossil fuels resource alternatives. The Hawaii IRP process has never incorporated a quantitative assessment of risk reduction in the overall generation portfolio. Of the various uncertainties facing the Hawaii electric markets, the fuel price is probably the most important.

The Critical Problem of Inaccurate Fuel Forecasts

The current HEI company projected fuel forecast, as presented in the ongoing IRP processes, is based on the EIA 2005 outlook, which is already so outdated that the referenced oil prices are consistently $20/bbl below observed future market oil prices for the next five years, after making adjustments to place the crude markers on a comparable basis. In essence, the reference case assumes that world crude oil will be between $29-35/bbl from 2005-2010, while the actual futures price in August 2005 (pre Katrina) for the same commodity ranged between $51-$55/bbl. Note that *this is before the weather-related market disruptions of Hurricanes Katrina and Rita.* It is difficult to determine whether the refusal to accept market reality is a result of indifference, incompetence, sheer denial, or something worse.

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[6] F. Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, December 2000. Available at: http://www.raponline.org

Since all the relevant planning decisions of what is “cost effective” are ultimately determined within the first five to seven years (due to both the impact of discounting and the obvious fact that the IRP plans are updated within that time frame), this gross understatement of costs skews the determination of cost effectiveness toward fossil fuels. This failure to acknowledge the realities of current liquid fuel markets is especially important because under the RPS Statute, Hawaii’s utilities must only comply with the RPS to the extent that renewable resources are determined to be cost effective. If such a misleading projection of fossil fuel prices is used as the basis for cost effectiveness determination for compliance with Act 95, then ratepayers will continue to suffer the impacts of high – and volatile -- fuel prices.

This blatant failure to make a serious effort to define the real future costs of fossil fuels is a reflection of the underlying problem that the IOUs have *no* incentive to manage fuel prices.

Paragraph 121:

Candidate Renewable Energy Resources in Hawaii
Appropriate Valuation Methodologies for Renewable Resources

1. Various Alternatives for Renewable Energy Resources in Hawaii

Hawaii is blessed with a climate that is especially conducive to a broad range of renewable resources. These resources, and the commercial projects that have been proposed, have been well characterized by the Hawaii DBEDT www.state.hi.us/dbedt/ert/renewable.html by Karen Conover of Global Energy Concepts. The availability of renewable resources in Hawaii has been most recently characterized by Bollemier and Associates, "*Study of Renewable and Unconventional Energy in Hawaii*" see http://hawaiienergypolicy.hawaii.edu/papers/bollmeier.pdf. In addition, the ongoing integrated resource plan studies for KIUC and HECO done by Black and Vetch provide an additional source of credible input (with some modifications noted in RMI's prior testimony on November 14, 2005). Therefore, we support EI's use of these studies for purposes of evaluating the viability of renewables in Hawaii.

All of these studies characterize the broad mix of renewable technologies including wind, geothermal, solar PV, solar thermal electric, geothermal, biomass and wave energy. Virtually every major study done on renewables in Hawaii suggests that the technical potential is at over 3.5 million MWh or 25—28% of total projected demand by 2018.

2. Valuation for Different Types of Renewables

There are three different types of renewable resources: firm, intermittent and distributed. Firm renewables include biomass, geothermal, solar thermal electric, biofuels, fuel cells that run on non-fossil fuels and, for purposes of Act 95, use of rejected heat for combined heat and power. Intermittent renewables include wind, solar PV, and run-of-river hydropower. Distributed renewables include solar thermal, solar PV on rooftops, seawater air conditioning systems, ice storage and quantifiable conservation measures.

We wish to remind EI that these resources must be evaluated differently as they relate to reliability contribution or capacity value. Firm centralized renewable power plants can be evaluated in an identical manner to fossil fuel plants, in terms of characterizing their capacity value. Intermittent renewable resources have a non-zero contribution to system reliability, which should be considered along with their operational integration costs. The marginal value of the reliability contribution of intermittent renewables will initially increase (due to the reduced variability of a geographically diverse portfolio of resources) and then eventually will tend to decline as penetration rate increases, because the additional variance in net demand caused by intermittency begins to outstrip the system capacity to respond to that variance; hence, the net reliability contribution declines and operational costs increase. These effects are especially pertinent in geographically isolated systems such as Hawaii, and therefore need to be included. Finally, distributed renewables avoid both generation and grid costs; their small scale, faster lead time, and modularity increase the net capacity value, particularly on small systems. All of these factors should be included in the valuation of distributed renewables.

The Rocky Mountain Institute had detailed the quantitative methodology to address these risks and values in its book, *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size (2002).* Thanks to generous support from the Hewlett and Luce Foundations, we are able to offer our advisory support to the Commission on how to incorporate these issues into the proposed Power Simulation Effort, as we will discuss in the technical workshop on October 5th. The general concepts of this approach were provided to the Commission in RMI's prior testimony and are repeated here as a reference in Appendix 1.

Paragraph 171:

Impact of Regulatory Incentives on the Behavior of Utilities
Assessment of Candidate IR Mechanisms
Potential Combinations of RPS IR Approaches

1. Impact of Regulatory Incentives on Behavior of Utilities

NARUC, the Regulatory Assistance Project, and academics have done extensive work on the impact of regulatory incentives on utility behavior. Rather than restate that body of work here, RMI makes some observations of the impact of IR schemes as they relate to the adoption of renewables by utilities.

The recommended candidates' incentive schemes should be evaluated on the relative impacts they will have on utility behavior, economic efficiency, renewable market development, and ratepayers.

The net impact of regulation to utility financial value, measured in share value, has historically been the single greatest determinant of IOU behavior. To be sure, it is not the only determinant; a variety of other management factors come into play. We hasten to observe that this is not the case with KIUC, where the ratepayers are the owners and, hence, net reduction in total bills (a product of rates and use) and the financial condition of the Coop itself would be the primary determinants of management behavior.

There is a strong body of management literature that suggests that a combination of rewards and penalties are effective in directing utility management behavior toward the desired societal goals. Finally, the IR structure for renewables cannot be considered in isolation from the overall rate-makings scheme for the utility, since the total incentive structure will guide behavior. With these caveats in mind, we now turn to a discussion of the seven proposed candidate schemes.

2. Assessment of Candidate IR Mechanisms

Of the seven candidate IR mechanisms, three of them are workable, either alone or in combination, one of them is partially applicable (REC trading system), and three of them are inappropriate for the market conditions in Hawaii (alternative compliance fees, utility pays or receives its avoided cost estimate, and utility receives incentives based on multiples). Let's address the inappropriate candidate mechanisms first.

The Fatal Flaw of Candidate 2: Alternative Compliance Fees

While alternative compliances fees are in use in other jurisdictions, the market conditions in Hawaii create a fatal flaw in the concept. Let's assume that there were cost-effective resources, and the utility was refusing to purchase them. (As discussed earlier, the investor-owned utilities have a strong incentive to promote the maximum use of their own fossil fuel generating assets.) Therefore, the alternative compliance fund money is placed into a renewable development fund. However, although a renewable developer could then gain access to the fund, he would still need a buyer for the power. Since Hawaii is not deregulated, the utility is the only buyer for renewable power projects larger than the distributed scale. This is a general problem of geographically isolated systems, with only a single buyer.

Thus, unless the alternative compliance fund cost was set above avoided cost, with shareholders bearing difference between alternative compliance fund and avoided cost, this approach will not be viable.

In the states that have chosen alternative compliance funds, they are either within integrated market systems, with multiple buyers and sellers, such as PJM or NEPOOL, and hence the monopoly buying power problem does not arise.

Overall, RMI does not believe this approach would be appropriate for Hawaii.

The Financial Incentives Problems with Candidate 3: Utility Pays or Receives its Own Avoided Cost

EI has neglected the most obvious "gaming" problem with this approach. This again related to the financial incentive that the utility sees in building and maximizing the generation from its own fossil plants. If the utility simply sets the avoided costs low, there will not be enough renewable power projects that can meet the artificial benchmark and it will be exempted from the requirement to meet the RPS targets. In short, this approach enshrines the status quo.

Only if the utility's cost recovery for both its renewable and fossil plants were capped at the forecast avoided cost, would the incentive to low ball the future avoided costs be removed. This approach would have the salutatory effect of having the utility use market forecasts for avoided costs wherever possible, and pay much closer attention to the fuel forecast. This essentially places the utility at risk for the fuel price hedge, as opposed to an approach where the PUC makes a determination of the prudent cost to pay for such a hedge. Bearing the full fuel cost risk would be undoubtedly unacceptable to the financial health of the utility.

The alternative game is to create artificially high avoided costs, and then either inflate the interconnection costs for non-utility renewable power or otherwise develop extreme operating requirements that inflate the costs for IPP-generated power. (Some IPPs have argued that investor owned utilities have used exactly this tactic in the past -- see testimony in the Apollo docket). In this case, the only economic alternative would be the utilities' renewable power facility. So long as the actual avoided costs meet or exceed the utilities' return on capital requirements, the utility has an incentive to attempt to monopolize the provision of renewable power.

The temptation to game the system with this approach is simply too great. Therefore, RMI does not believe this approach would be appropriate for Hawaii on any other geography.

Practical and Equity Problems with Candidate 7: Utility Receives Share of Avoided Oil Cost times Societal Multiple

RMI agrees with the economic principle that import substitution activities create an economic multiplier effect. The academic literature provides guidance on estimating that impact, though the social science is inexact and the range of multiples tends to be large. The practical problem is defining an acceptable multiple based on incontrovertible evidence. The introduction of a much broader and complex inquiry into the ratemaking process would make the prior experience in attempting to estimate externalities feel like the proverbial walk in the park. The profit maximizing tendency would be for the utility to introduce expert witnesses with high estimates of the multiple, while the resource strapped Commission and Consumer Advocate would be forced to attempt to rebut.

Beyond the practical issues, there is a significant equity concern. The purpose of the RPS is to provide ratepayers with lower costs, by virtue of buying a cost effective physical hedge on fossil fuel prices. The economic benefit that ratepayers receive from lower power prices is the basis of the multiple. In essence, not only does the utility get a share of the direct reduction in the costs of fossil fuels, but it also gets a share of the indirect economic benefits from the overall economy due to the increased disposable income of the ratepayers. These indirect economic benefits are not distributed in equal proportion to the direct benefits across each sector of society. Economic theory suggests that those members of society who have surplus capital to invest will economically benefit more from increased disposable income than the poorer elements of society. It is hard to understand equitable basis for the ratemaking principle that requires all consumers to give up a share of the overall economic growth to the utility.

RMI does not believe this approach would be appropriate for Hawaii or any other geography.

The Partial Applicability of Candidate 1: RECs

RMI believes that RECs could be viable on an intrastate basis, but would have negative unintended consequences if applied on an interstate basis. The details of RMI's reasoning are discussed in our prior responses to Paragraph 106.

The Viability of Candidate 3 and Candidate 6: Penalties

RMI concurs with the primary findings of EI regarding penalties. A lack of a penalty does not necessarily mean that the RPS will fail. However, the inclusion of a penalty that is high enough to encourage appropriate utility behavior and has adequate safeguards will increase the likelihood that the RPS will succeed.

Most states that have penalties use financial penalties that are higher than the cost of compliance so that it is in the utility's interest to comply with the standard instead of trying to evade it. Maine and New Jersey allow for license revocation; Connecticut charges 5.5 cents/kWh; Massachusetts charges 5 cents/kWh for alternative compliance; Wisconsin's fines range from $5,000-$500,000; and Texas fines the lesser of $50/MWh per deficient TRC or 200% of the average TRC cost for deficient credits.

Potential Penalty Approaches for Hawaii

There are two potential penalty schemes for Hawaii, both of which have advantages and disadvantages. The first penalty scheme is a flat 5¢/kWh (or larger given the avoided costs in Hawaii) fine that is similar to Connecticut's 5.5¢/kWh fine. This penalty is advantageous because it is easy to administer. To lower administrative costs, the Hawaii PUC could create an automatic enforcement that takes effect at the end of the compliance period. Flexibility could be integrated into this penalty scheme by allowing tradable credit banking. However, the penalty itself is static and does not reflect the costs to society.

A more economically efficient penalty scheme would be to charge the utility the full total system cost for failure to bring in the marginal renewable resource. The total system losses would be calculated in the same manner as the total system benefits in the incentives presented above. The difference is that the Commission must use its model to define the marginal renewable resource in any given year that should have been deployed but was not. Charging the utility the entire cost in ¢/kWh for each deficient kWh creates a powerful incentive to meet the RPS targets, and holds ratepayers harmless for the utilities' failure to do so. The reduced return on equity variant has a similar impact; it also holds the utility harmless if the Commission deems that no cost effective renewable resource was available, and hence is adaptive to a change in fossil fuel prices or power technologies.

The claw back of utility profit is a variant of this approach that creates an even stronger financial edge. The challenge, of course, would be the determination of what actions the utility took to generate its undeserved profits. In other words, the calculation of the "incremental benefit" may become a rate case unto itself, which results in added administrative burden.

However, sticks without carrots may not be the right approach. We encourage the Commission to adopt both a penalty and an incentive scheme as it creates Hawaii's RPS regulations. We suggest that whatever penalty scheme is adopted be transparent, easy to administer, and consistent with the ratemaking approaches in place.

The Viability of Candidate 5: Utility Receives a Share of Societal Benefit

RMI strongly favors this approach as an RPS incentive. This incentive works in the following way. The net societal benefit equals the correctly defined avoided cost minus the actual fixed price paid for the renewable power project. The utility gets a share of this difference. Thus, if the levelized avoided cost in 2005 over the next 15 years was 15¢/kwh, and a renewable power plant owner was willing to accept 10¢/kwh for a fixed 15 year contract to produce power, the net societal benefit would be 5¢/kwh. The PUC would reward a portion of that benefit to the utility, the remainder would accrue to ratepayers. For example, a 20% share of the savings would be 1¢/kwh.

The purpose of the procurement of renewable power is to lower the total societal costs. The regulatory system should be designed so that the utility is indifferent about whether its capital is used to lower societal costs or other costs. By contrast, under the current system, purchased power costs are directly passed on to the consumer through the energy cost adjustment. Hence, the utility has no incentive to purchase third party renewable power, and a substantial incentive to maximize its own fossil and renewable power. The next question is whether the determination of avoided costs is prospective or retroactive. While the retroactive approach is used today and far easier to administer, it does not solve nor address the basic problem that consumers do not receive any benefit from the hedge on fossil fuels unless the utility builds the renewable power plant.

Thus, a prospective determination by the Commission of the future avoided costs to be used in defining a 15-year contract for renewable power would be preferred. In this approach, the best available market data, the futures market, Asian market options and the current valuations of oil reserves, would be assessed on an annual or biannual basis by an independent consultant to the Commission. Renewable contracts for power that are less than the full avoided costs are most cost effective.

Once the contract is entered into, the utility receives its share of the societal savings (the difference between the contract price and the avoided cost price, or the difference between the utilities' own cost and the avoided cost price), and the ratepayers receive the remainder. If a competitive bidding process is used to source the renewable capacity, then all parties have the incentive to provide the lowest cost power in order to win the bid.

If the utility builds its own renewable power plant, the share of societal savings received will have to be adjusted to prevent the utility incentive to favor its own renewable power plants over those of others. In the example above, if a third party built the plant, the utility would get 1¢/kwh in incremental shareholder margin. If the utility built the identical plant at the same costs, it would receive a greater amount due to the equity return on capital (embedded in the 10¢/kwh contract price), hence share of savings *may* be needed to address this problem. The alternative to adjusting the share of savings would be a combination of competitive bidding and other safeguards to prevent overstatement of IPP interconnection costs.

3. Potential Combinations of RPS IR Approaches

The following matrix may serve as a helpful starting point for the discussion regarding the appropriate combination of PBR regimes, and renewable IR regimes:

PBR Regime	Renewable Incentive
Traditional rate of return	1. Rate base adder for renewable power plant investments done by the utility or IPPs 2. Overall utility ROE increased or decreased based on achievement of target RPS level 3. Flat rate penalty for failure to comply 4. Intrastate REC trading with cap equal to penalty
Revenue Decoupling Revenue Cap approach	1. Utility receives share of total system savings, as measured by societal resource test, as incentive for incorporating cost effective renewables in the system or pays a penalty for failure to do so based on societal losses 2. Same as above, but based on total resource test 3. Commission determines prudent future avoided costs based on annual or biannual independent assessment 4. Intrastate REC trading with cap equal to penalty
Price Cap CPI-X Approach	1. Commission determines prudent future avoided costs based on annual or biannual independent assessment 2. Utility receives share of total system savings as measured by total resource test as incentive for incorporating cost effective renewables that lower risk adjusted rates (and pays penalty proportional to rate increase), or 3. Revert to IR mechanisms of traditional ratemaking approach 3. Intrastate REC trading with cap equal to penalty

In general, RMI believes that the revenue decoupling approach will achieve the greatest long term alignment with utility behavior and societal benefit. However, since revenue decoupling removes both the downside and the upside from the utility financial returns, it should be combined with a share of total system savings from renewables (or efficiency) in order to ensure that the utility has a steadily growing earnings stream from which to pay dividends.

If the Commission decides to continue with the traditional rate of return approach, then it is opting for a simplified approach to ratemaking. It is logically consistent that the incentives and penalties associated with the RPS should be easy to administer. Given the disincentives for renewables, some degree of ratebase adder will be needed to create an incentive for the utility to pursue renewables at all, even if it favors their own plants versus others (hardly an ideal situation). We note that any renewable incentive created should not include financial incentives for the utility to build its own renewable resources compared with procuring those renewable resources from others. Rate base adders under traditional rate of return regulation can create this societally perverse incentive, unless construed to include renewable power purchases from IPPs. We further observe that the traditional approach does not necessarily address the fundamental problem associated with the utilities' lack of incentive to manage fuel price risk or the failure to transfer the savings from renewables to consumers.

The price cap approach is a regulatory regime in favor in most Commonwealth countries and some US states. In essence, the rates are frozen at a specific level and ratcheted down based on the combination of the consumer price index and an efficiency factor, X. The intent is to focus the utility on becoming more efficient through the prospective imposition of lower rates in future. Utilities tend to respond by reducing expenses (and capital) to keep costs well below the price cap and/or increasing load growth beyond the rate case projections. Both actions allow the utility to capture additional profits between ratecases.

Within this context, the Commission has a series of choices. RMI believes that it should always take the role of prospectively determining the prudent level of future avoided costs, in order to allow the utility to enter into fixed price contracts that are deemed prudent. This addresses the paramount concern of providing ratepayers with the benefits of the renewable hedge.

RMI would suggest a modified version of the societal savings or cost approach that calculates the rate impact, and rewards or penalizes the utility accordingly. This is very similar to the societal cost approach, although the rate impact is calculated vs. the prospective sales projections that were used to define the price cap initially. This may over- or under-capture the actual impact, due to differences in actual sales. True up accounts could be used for an adjustment, though this mechanism is typically not in place in the price cap approach. Alternatively, the Commission could adopt a simpler system or incentives used in traditional ratemaking.

The flexibility mechanism of intrastate trading appears to be a useful addition regardless of the ratemaking mechanism chosen.

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Appendix 1: Appropriate Valuation Methodologies for Renewable Resources

The economic viability of renewable energy in Hawaii depends on several factors which we discuss in detail below:

a. Oil prices and price volatility
b. The cost of renewable power technologies
c. The degree of capacity credit assigned to renewable technologies
d. System integration and interconnection costs
e. Financial engineering and tax credits
f. Hedging Value

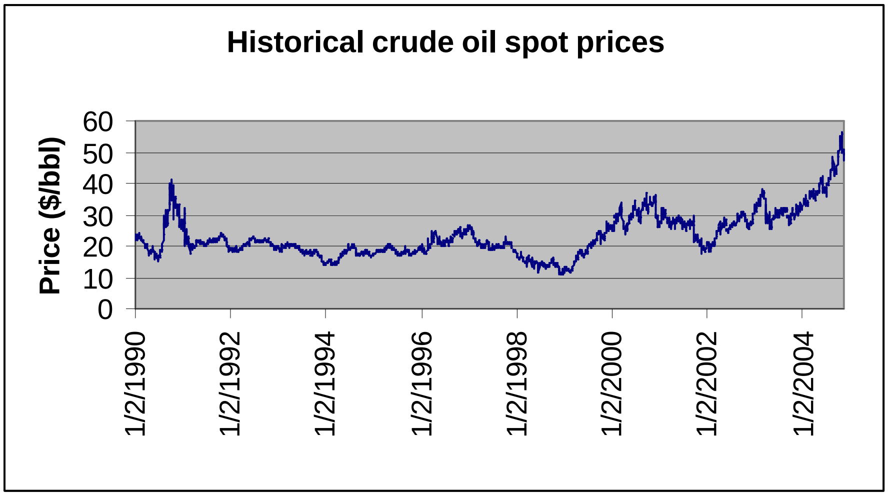
a. Oil Prices and Price Volatility

Renewables serve as a hedge on fossil fuel costs, and displace fossil fuel generation by the utility. Thus, the economic viability of renewable power is inextricably linked to the future price of fossil fuels, particularly oil. Although oil prices are notoriously hard to forecast, the near term price is evident in the futures market. At the time of RMI's November 2004 testimony, NYMEX futures price of crude oil, which, was trending down $50/bbl towards $42/bbl. These prices are r far higher than historical levels.[7] Prices have gotten far worse since then. The August 2005 NYMEX futures held prices between $55-$65/bbl over a five year period. Post Katrina, prices have only gone higher.

Price fluctuations in oil are not reflected in the futures market, but can be seen clearly in the following chart of crude oil spot prices (pre-Katrina).[8] Thus, the volatility of oil is extremely high, and becoming higher.

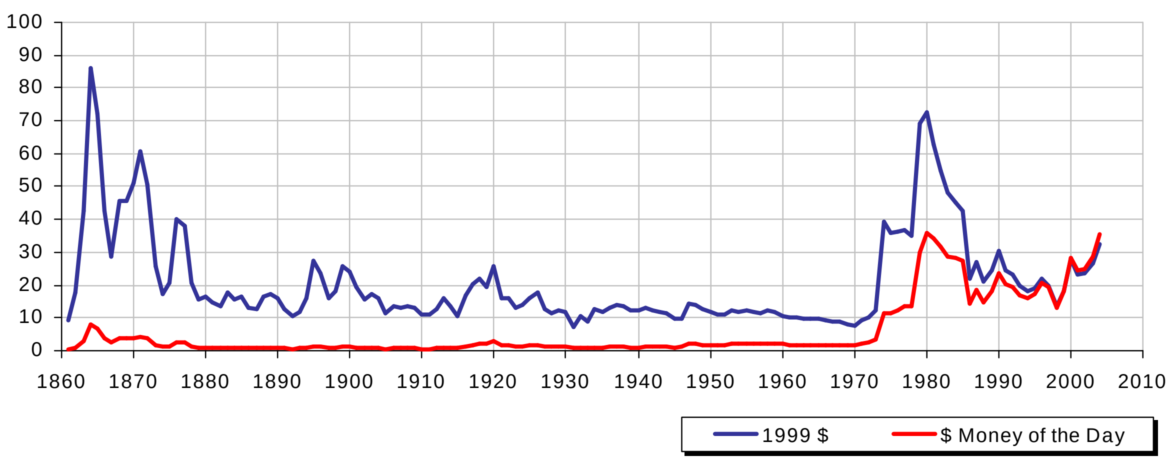
[7] NYMEX.com. Light, sweet, crude oil, 11/11/04 session. Accessed on 11/11/04 at http://www.nymex.com/jsp/markets/lsco_pre_agree.jsp.

[8] EIA (Energy Information Administration). US Crude Oil spot prices. Available at http://www.eia.doe.gov/oil_gas/petroleum/info_glance/crudeoil.html.



Finally, taking a 100 year view, we can see that oil prices in real dollar terms have reached a level of price and volatility not seen for nearly 80 years. It is very clear that the age of cheap oil is over.

Crude Oil Prices, 1861-2004
US Dollars Per Barrel[9]



The Rocky Mountain Institute has recently issued a major new study on oil and its alternatives, *Winning the Oil End Game* (2004) (see www.oilendgame.com). Our conclusion on oil price movements is that three major factors will determine future prices:

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[9] Shell 2050 Scenarios. Available at *http://www.eia.doe.gov/emeu/international/petroleu.html#IntlPrices*

- The balance of global supply and demand
- The risk premium associated with terrorism and market disruption
- The degree of technical trading in the commodity

Today, these three factors have conspired to send oil prices soaring into the high $40s-low $50s/bbl. The fundamentals of supply and demand have been shifted by China and India's voracious appetite for oil combined with continued US growth, so that supply and demand are balanced at 82 MMbbl/d. Hence any disruption in supply can send prices higher. Whether this continues depends on the ability of the US, China and India to move down a more energy efficient path for transportation and economic development, more than it depends on the ability to bring on new supplies.

Thus, we conclude that we must recognize that oil is likely to maintain a higher price plateau of mid $40s to low $50s in the near term, with a longer-term equilibrium in the mid $30s. Oil company valuations are already valuing oil company reserves in the mid 30s, confirming this point of view. Unfortunately, HECO and HELCO, in the current IRP analysis, have remained wedded to the an unrealistically oil price forecast, which expects crude oil prices (in real dollar terms) to remain in the mid $30s based in EIA's 2005 reference case. If the HEI companies truly believe this is accurate, we challenge them to buy any oil reserve for the prices they forecast. The market is a far better indicator of the prices Hawaii's ratepayers will pay. Thus, HEI companies grossly underestimate the economic viability of renewables and their value on the system.

b. The Degree of Capacity Credit Assigned to Renewable Technologies

The economic viability of all generation plants depends on the revenue streams they receive. Fossil plants, which are firm and dispatchable, receive both capacity and energy payments. Most renewables power generators receive only energy payments for some or all of the energy they produce, and essentially are given zero capacity value. Such is the case in Hawaii. Given the very high avoided capacity costs in Hawaii (>$1000/kW), a higher capacity value can greatly increase the economic viability of renewable power projects.

Although wind has typically been procured by utilities on an energy only basis, there is increasing acceptance that wind generation does contribute to system reliability, and therefore has capacity value. Standard utility reliability or production cost models can be used to calculate wind capacity value, or simpler models that approximate this value can be employed. The evidence is increasingly clear that many renewables should be given some degree of capacity payments, and more US utilities are incorporating this reality into their generation planning processes and avoided cost payments. We explain the reasons why below.

While fossil fuel plants tend to have high capacity values per rated MW (on the order of 95%), wind farms are often assigned low capacity values (often zero) due to the high variability of their output. If a wind farm cannot guarantee a particular capacity, other resources must be committed as back up in an amount equal to the wind farm's output. But is this conventional wisdom approach accurate?

Geographically distributing wind resources has the potential to reduce the variability of the portfolio output to such an extent that the portfolio is worthy of capacity credit. Topography and weather patterns contribute to different wind regimes in different locations. In essence, the variability of wind in one geographical location to some extent cancels out the variability of the wind in another location. Further, portfolios of renewable resources may demonstrate covariance in output during peak periods, so that the portfolio of renewables deserves higher capacity credit than each individual resource considered in isolation.

Furthermore, winds sometimes exhibit seasonality or diurnal variation that results in a statistically significant peak coincidence. In this case, the wind farm contributes positively to the overall reliability of the system and deserves an associated capacity credit.

Methods of calculating capacity credit have been developed by wind and utility experts around the country. One approach to determining a wind farm's capacity credit is to calculate its effective load carrying capability (ELCC), a metric created by the National Renewable Energy Laboratory (NREL), and applied most recently by the California Energy Commission (CEC) in their renewable generation integration cost analysis. This approach is useful because it can be applied to any type of generating resource, whether fossil fuel or renewable. The ELCC equation says that the increase in capacity that results from adding a new generator can support x more MW of load at the same reliability level as the original load could be supplied.[10] The ELCC is based on the loss of load probability (LOLP), which is the probability that enough generation units are on forced outage that the utility is unable to meet its load, thereby quantifying the risk of not supplying enough generation to the system. When this method was applied to existing wind farms in California, capacity credits were determined to be 22-26%. Since these existing California wind farms were built, turbine technology has been developed to improve energy capture at low wind speeds. The CEC believes if this technology were installed at the existing sites, the capacity credits would be significantly increased. California is not alone in using this methodology. In the review of Xcel's 1999 integrated resource plan, all parties including Xcel and the Colorado Public Utility Commission agreed to adopt ELCC as the wind capacity value measure of choice.

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[10] Kirby, Brendan, et al. *California Renewables Portfolio Standard: Renewable Generation Integration Cost Analysis, Phase 1*. California Energy Commission. December 2003.

While this is a rigorous method, the CEC and others have recognized that this iterative approach is perhaps overly complicated and time consuming, and have made efforts to develop simpler methods. One of these methods calculates the capacity factor of the wind farm over the top 10-20% of load hours and uses this as an approximation for the ELCC. This approach is substantially more generous to wind than the iterative ELCC method.

A third method, and perhaps the most conservative, involves calculating the mean and standard deviation of an optimized portfolio of wind resources. Capacity credit is then assigned at the 95% probability level (i.e there is a 95% probability that power will be produced at that level or above).

In Hawaii, wind data from geographically dispersed locations exist that make possible an analysis of the reduced variability from a portfolio of wind. A similar analysis conducted with wind data from North Carolina found that distributing wind between three sites around the state could result in a portfolio variability equal to roughly 30% of the average variability at any individual site. These same data can also be easily compared to determine whether wind around the state exhibits any statistically significant peak coincidence. Geographical dispersion and peak coincidence can increase the viability of renewable energy investments.

There is no question that the actual capacity credit given renewables should be based on the amount of physical assets they defer on the system. Therefore, on small geographically isolated systems, the underlying analytical task is to define from a planning and an operational perspective, what the incremental benefit (or cost) of adding more intermittent renewable generation is.

We conclude that evaluations of renewable technologies in Hawaii either as part of an IRP, or for the determination of avoided costs, should estimate the reliability benefit of the renewable technology to the utility system, and provide capacity credits accordingly.

c. System Integration and Interconnection Costs

While wind is an intermittent generation resource, generation output from wind farms is more stable than the term “intermittent” may suggest. Grid connected wind farms typically have capacity factor levels of ranging from 25-40% or more over the course of a year. A common misconception about wind power is that turbines are either on or off and sit dormant for much of the year. In actuality, wind turbines are capable of partial output and most wind farms are generating at some level of generation during 70-90% of hours in the year. Further, there are a number of factors that smooth the output of a wind farm relative to variations in actual wind speed.

Much like electric load, wind exhibits a high variability that must be addressed by the utility on three time horizons:

- *Unit commitment*: most vertically integrated utilities decide which resources to dispatch 12-24 hours ahead of when they will be needed. These decisions to commit units are based on historical demand during the upcoming time period, recent trends in demand and weather, and the cost of each resource at that time. Unit commitments can be made because the dispatcher has confidence that a particular resource will or will not be available to produce a certain amount of power during the upcoming day. Because wind is currently so variable, utilities find it difficult to include wind in these day-ahead unit commitments. The amount of capacity committed for the upcoming day is generally the base amount that is forecast to be demanded during the entire period.

- *Load following*: Throughout the day, demand generally trends up or down. In response, utilities add resources to the generating mix, or increase or decrease existing resource energy output every five to ten minutes. Load following is somewhat predictable based on recent trends, and patterns of customers tend to be correlated. Because this pattern is fairly reliable across days, utilities must have resources ready that can be economically turned up or down throughout the day. To meet trending demand, the dispatcher must have control over the power output of these resources.

- *Regulation*: Regulation deals with minute-to-minute variations in the balance between generation and load; that is, the fluctuations (± 1 MW) around an underlying trend. These fluctuations are generally not easily forecast.

Integrating wind power on these three time horizons represents an added cost to the system. Several utilities, government agencies, and consultants around the country have undertaken studies of wind integration costs on their utility systems, and the results shown in the following table can help inform Hawaiian utilities.

Summary of Integration Costs from Previous Studies[11]

Study	Relative Wind Penetration (%)	Regulation ($/MWh)	Load Following ($/MWh)	Unit Commitment ($/MWh)	Total ($/MWh)
UWIG/Xcel	3.5	0	0.41	1.44	1.85
PacifiCorp	20	0	2.50	3.00	5.50
BPA	7	0.19	0.28	1.00-1.80	1.47-2.27
Hirst	0.06-0.12	0.05-0.30	0.70-2.80	na	na
We Energies I	4	1.12	0.09	0.69	1.90
We Energies II	29	1.02	0.15	1.75	2.92
Great River I	4.3				3.19
Great River II	16.6				4.53
CA RPS Phase I	4	0.17	na	na	na

These studies report integration costs ranging from $1.47 - $5.50/MWh. Despite the differences in these utility systems in terms of generation mix and load profile, the results of their integration cost studies are remarkably similar; the overwhelming result being that integration costs, at a range of wind penetration levels, are low. There is no apparent reason to think that wind integration in Hawaii would fall outside of this range, except for minimum turndown issues on some systems.

The minimum turndown issue is based on the cost of turning down fossil fuel steam plants during the off peak hours, due to additional wind generation on the system when load is already low. These costs are essentially a heat rate penalty that the system would incur if the fossil steam plants were turned down below their minimum operating level and had to be reheated. While this is a valid cost to consider, it assumes that there are no energy storage options on the system.

Energy storage, such as pumped hydro, could be used to absorb the excess wind generation, eliminating the minimum turndown problem. This reinforces the point made earlier that renewable power must be considered as a portfolio of resources and how they impact each utility system, in order to correctly assess the underlying economic value.

Recent studies by DBEDT have suggested that on island systems, additional assets, such as batteries, may need to be deployed to provide the necessary regulation energy. RMI believes that the correct approach to valuing renewables is to identify the appropriate

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[11] Smith, JC et al. *Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date.* National Renewable Energy Laboratory. March 2004. NREL/CP-500-35946.

portfolio as assets necessary to integrate increasing amounts of renewables on the utility's system, and then defer the appropriate amount of capacity and long run energy accordingly.

d. Financial Engineering and Tax Credits

Tax credits have a significant impact on the overall financial viability of renewable projects. The State of Hawaii has provided generous tax credits to renewable generation technologies such as wind and solar. The Federal Production Tax Credit of 1.9¢/kwh, has recently been approved in the 2005 Energy Policy Act, and should be incorporated, along with incentives for other forms of generation.

Finally, carbon credits should be included in the evaluation of renewables, using the global market prices for these credits. Now that the Russia has signed the Kyoto Protocol, this accord will take effect. The liquidity of international carbon credit markets is increasing, making the posted prices more reflective of the market. Although the US has not signed the protocol, and carbon credits can only be monetized in the voluntary markets such as the Chicago Climate Exchange, a long run analysis should take the carbon credit value into account.

e. Hedge Value against Fossil Fuel Prices

The viability of renewable energy investments increases when taking into consideration the value of renewables as a hedge against fossil fuel prices. Energy planning should focus less on finding the single lowest cost alternative and more on developing efficient generating portfolios—those that maximize expected return for a given level of risk, and minimize risk for a given level of expected return.[12]

Price fluctuations make fossil fuels inherently risky; therefore adding "riskless" fixed-cost renewables to a portfolio of conventional generating assets serves to reduce overall portfolio cost and risk, even though their stand-alone generating costs may be higher.[13] By using established financial portfolio theory, Awerbuch demonstrates that the relative value of generating assets should be determined not by evaluating alternative resources, but by evaluating alternative resource portfolios.

[12] Awerbuch, Shimon. *Applying Portfolio Theory to EU Electricity Planning and Policy-Making.* IEA/EET Working Paper, February 2003. EET/2003/03.

[13] *Id.*

In the above chart from Awerbuch, point M represents the 1998 optimal mix of coal and gas fired generation in the US, based on a riskless renewable price of $0.12/kWh. If the price of renewables decreases to $0.08/kWh, the optimal mix of coal and gas (based on portfolio optimization of two risky assets) moves to point N. As renewables are added to the portfolio, the optimal portfolio shifts down towards point L. A renewable portfolio share of as much as 25% leaves overall portfolio generating costs unchanged, but provides significant risk reductions.[14]

In conclusion, the viability of renewable energy investments must take into consideration several factors. While integration costs are real, studies from around the country demonstrate that these costs are low. Wind investments could be given some level of capacity credit, based on the benefits of reduction in variability due to geographical dispersion and peak coincidence. Finally, because renewable investments are riskless, considered as part of a generating portfolio, they can act as a hedge against fossil fuel price fluctuations, and potentially decrease both the cost and risk of the generating portfolio.

Summary

In interconnected utility systems in the United States, many of the operational costs and benefits can be evaluated based on the prevailing power markets of the particular

[14] *Id.*

region. For example, ISO-New England and the Pennsylvania-Jersey-Maryland Interconnection (PJM) explicitly value capacity and several ancillary services. Thus, the analytic task is to correctly understand the impacts of intermittent generation, then use the market to evaluate the economic benefits or costs, and finally to apply financial theory to correctly account for risk or uncertainty.

This is not the case for geographically-isolated power systems without interconnection that are typical of the utilities within the Hawaiian Electric Company (HECO) system. In these systems, theoretical benefits or costs of renewable or distributed resources are not continuous functions. In isolated systems, there must be physical assets, either on the supply or demand side, that are collectively capable of providing the necessary power-services reliability. Thus, if intermittent renewable resources impose operational costs on a particular time scale, there must be a physical asset dedicated to managing the combined variations of supply and demand. Further, even though the correlation between an intermittent renewable resource and peak load means that LOLE is improved, the net benefit in terms of capacity credit must be defined by the set of renewable and other assets (such as storage or demand response) required to displace conventional power generation capacity.