Rhode Island Energy Efficiency and Resources Management Council (EERMC):

Opportunity Report – Phase I

Submitted on July 15, 2008 to:

The Rhode Island Public Utilities Commission, the General Assembly, the Office of Energy Resources, and National Grid

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Overview and Summary

I. Introduction

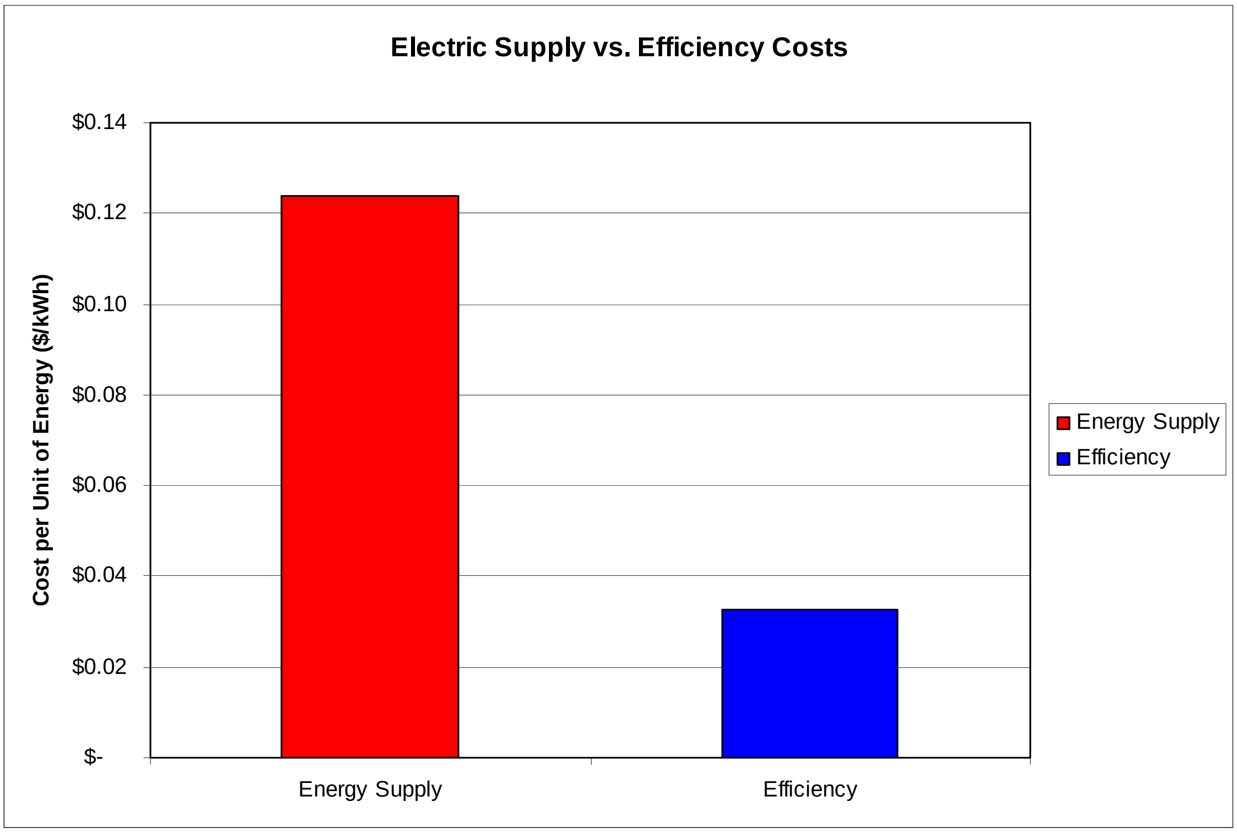
As part of its responsibilities set out in The Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006, the Rhode Island Energy Efficiency and Resources Management Council ("EERMC") hereby submits this Opportunity Report-Phase I to the Public Utilities Commission, the General Assembly, the Office of Energy Resources, and National Grid. This submission is also consistent the Standards for Energy Efficiency and System Reliability Procurement approved by the PUC at the June 12, 2008 Open Meeting.

In the past eight years, the cost of purchasing electric supply from generators in New England has more the tripled, from 3.5 cents per kWh, with the rates paid by Rhode Islanders for supply now at 12.5 cents per kWh. This dramatic rise in the price of electric supply is a result of tightening global markets for fossil fuels and the resulting increases in commodity prices for oil and natural gas, as natural gas power plants almost always set the marginal price for electricity in New England.

In the past, the General Assembly required the distribution utility, National Grid, to invest in an arbitrary, fixed amount of low-cost energy efficiency programs to help customers save money and lower their energy bills. Over the last decade these efficiency programs, energy audits, and rebates for efficient appliances, light bulbs and the like have delivered energy savings for RI ratepayers at the low cost of 3 cents per kWh.

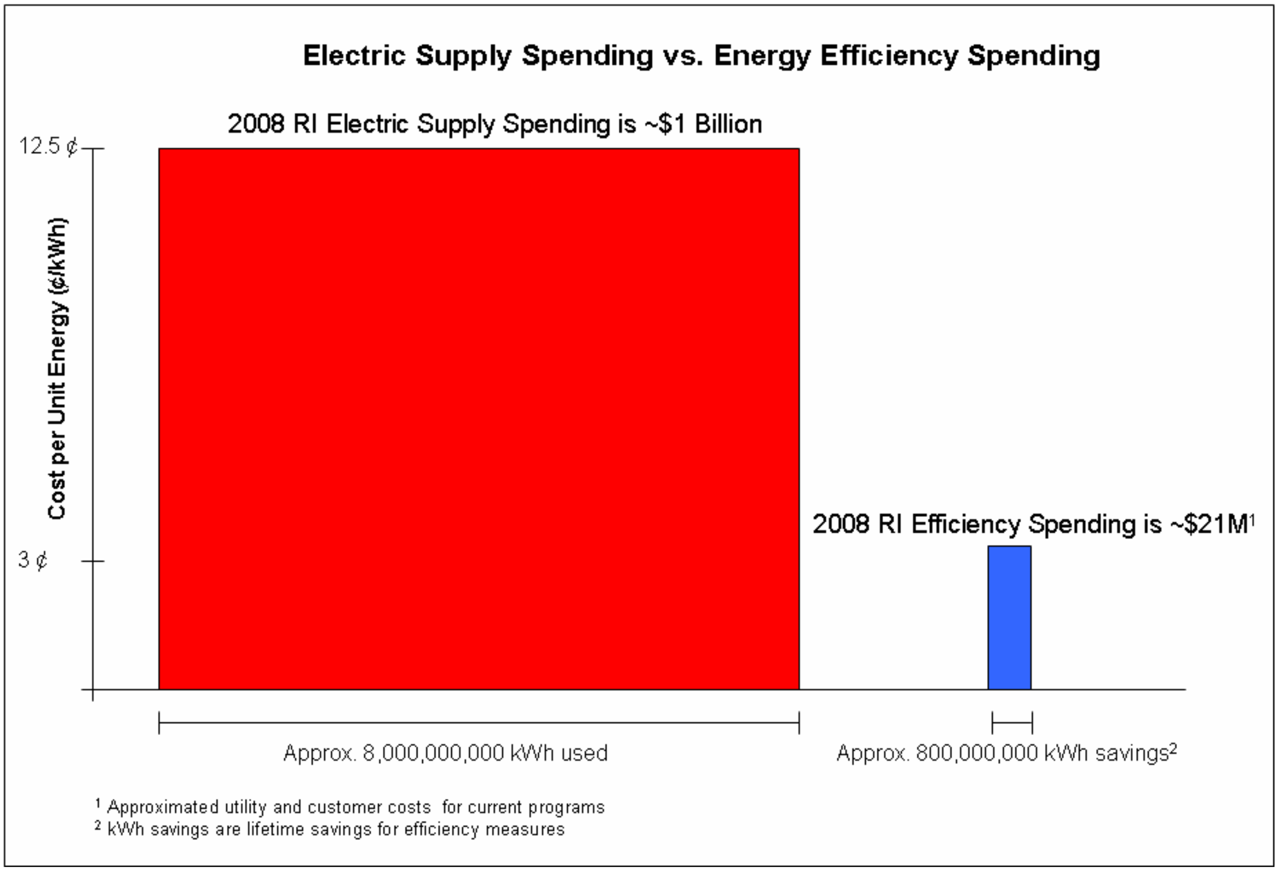
Showing foresight, in 2006, the General Assembly ushered in a new era for energy efficiency, moving from an "arbitrary" model for efficiency with a required, fixed utility investment level of 2.0 mills to an "economic" model for efficiency; one that directs the utility to invest dynamically overtime in all energy efficiency that is cheaper than supply. In the past, the General Assembly required National Grid to invest just $16 million in energy efficiency resources, leaving the remainder, roughly $1 billion, to be spent on electric supply regardless of the cost of each.

Through the 2006 Act, the General Assembly and Governor made the groundbreaking choice to require the utility to invest in all energy efficiency that is cheaper than supply. At a time when we see electric supply costing 12.5 cents per kWH and rising, and energy efficiency resources only cost 3 cents per kWh saved, this policy of investing in all energy efficiency that is cheaper than supply is sound, strategic, and an economic imperative. Figure 1-7 from KEMA's Efficiency Report illustrates the cost difference between electric supply and electric energy efficiency resources.



On September 1, 2008 National Grid is required by law to submit a Least Cost Procurement Plan describing how it will meet the legislative mandate by procuring low-cost efficiency resources in Rhode Island. The PUC's Standards for Energy Efficiency and System Reliability Procurement as approved by the PUC on June 12, built upon draft recommendations from the EERMC and OER, with input from many stakeholders, specifies details and a process for how the September 1st Energy Efficiency Procurement Plan should be prepared and submitted. In this Plan the utility will need to describe how it will help Rhode Islanders save money on their energy bills, through strategic cost-effective efficiency investments in their homes, businesses, hospitals, schools, institutions, and places of work and worship.

Figure 1-8, found in the Executive Summary of KEMA's Efficiency report, illustrates how the 2008 status quo of spending does not reflect Least Cost Procurement. This imbalance in resource acquisition is what National Grid must move to fix through its 2009-2012 Energy Efficiency Procurement Plan and supplemental annual Efficiency Program Plans. The goal of the Plans will be to ensure that Rhode Island ratepayers no longer spend so much for high cost electric supply when less expensive efficiency resources are available in the state.



The 2006 Act was also groundbreaking in that requires National Grid to submit a System Reliability Procurement Plan including resources such as distributed generation, combined heat and power (CHP), renewables, and demand response in order to foster a more dynamic, homegrown energy system.

The General Assembly established the EERMC in the 2006 Act with representatives from the business, residential, low income, buildings, and environmental communities to help oversee and provide input into the development and implementation of National Grid's Least Cost Efficiency Procurement and System Reliability Procurement Plans. The EERMC is charged with producing an "Opportunity Report" to identify the opportunities that exist to procure low-cost efficiency resources as well as system reliability resources such as distributed generation, renewables, and demand response. This Opportunity Report is being submitted today to the Public Utilities Commission, the General Assembly, the Office of Energy Resources, and National Grid in compliance with that statutory charge.

Since Rhode Island has decided, as a matter of law, to require the utility to acquire all energy efficiency savings opportunities that are lower cost than supply, the efficiency part of the report focuses on two key questions: "How much is it possible to save?" and "How much efficiency is out there that is cheaper than supply?" This Opportunity Report – Phase I is an important first estimate of the potential for saving Rhode Island consumers and businesses money on their energy bills through efficiency resources in the state. Its aim is to help guide and inform National Grid, state regulators, and community leaders as they develop the strategies necessary to secure all efficiency resources that are less expensive than supply.

It is important to note that in light of the fact that supply prices change over time and low-cost efficiency resources are both used up and replenished with technology innovation, the energy efficiency portion of the Opportunity Report is really the beginning of a dynamic and iterative process to constantly find better and cheaper ways to secure cost savings for ratepayers through energy efficiency resources. The report is intended to: (1) inform the National Grid's Least Cost Procurement Plan due September 1st to the Public Utilities Commission by taking a snapshot of the magnitude of the cost-effective efficiency opportunity in Rhode Island and (2) inform the utility's System Reliability Plan also due September 1st by identifying Rhode Island CHP, renewables, and demand response resources.

II. Overview

The General Assembly designed the 2006 Comprehensive Energy Bill to maximize ratepayers' economic savings by placing a clear requirement on the distribution utility to procure all energy efficiency that is less costly than supply. To help determine the quantity of such efficiency resources and the cost savings to be enjoyed by Rhode Island ratepayers, the General Assembly charged the EERMC with producing an Opportunity Report that would identify: (1) the quantity of low cost efficiency resources existing in Rhode Island homes, business, and institutions and (2) System Reliability resources such as distributed generation, small scale renewables, and demand response in the state. The studies that follow were commissioned, directed, and managed by the EERMC to meet these goals. These studies are to be used by National Grid in developing its Least Cost Efficiency Procurement and System Reliability Plans, and by the EERMC in guiding the development of state policies and practices consistent with the findings and directives of the 2006 Comprehensive Energy Bill and the PUC's Standards for Energy Efficiency and System Reliability Procurement.

The KEMA report (Attachment I) is an assessment of the electric energy efficiency potential in Rhode Island that is less expensive than supply and a preliminary assessment of the demand response (load management focused on peak summer electric impacts) potential. It will guide National Grid as it prepares its 3-year Least Cost Efficiency Procurement Plan by estimating the magnitude and cost of such efficiency resources and suggesting the new measures, program approaches and delivery strategies that will grow its current high quality energy efficiency programs into nationally leading least cost procurement efforts.

The NESCAUM study of opportunities for Combined Heat and Power CHP (Attachment II) adds a new dimension to the Rhode Island resource procurement strategy as this technology can provide significant efficiencies as well as customer, environmental and economic benefits. National Grid, on both the gas and electric sides, will be developing strategies to actively support CHP installations where they are cost-effective.

Finally, the University of Rhode Island (URI) report (Attachment III) is an assessment of the potential for small-scale renewable energy installations. Generally these installations will be on the customer side of the meter and will show up as a reduction in utility energy demand and consumption. URI indicates that the level of adoption of these measures in Rhode Island is limited, and the infrastructure to deliver these measures needs considerable development.

The EERMC wants to emphasize that we are pleased to meet this deadline for submission of the Opportunity Report, but we recognize that in an era of Least Cost Procurement and dramatic changes in energy markets and prices, such a report is only a "first step" in learning what levels of savings and distributed resource acquisition are really possible. As indicated in the KEMA report, there will be a "Phase II" of the opportunity assessment as we look more closely at Rhode Island businesses and homes. Similar follow-up and refinement of the estimates of potential will take place for all other resources and the Energy Efficiency and System Reliablity Procurement Plans themselves are required by Rhode Island law to repeated every three years.

Indeed, it is one of the characteristics of Least Cost Procurement that there will not be an arbitrary amount of resources procured; rather, the utility, the EERMC, and regulators will be continuously engaged in assessing how the state’s energy needs can be met in the most affordable manner. This is truly a new dynamic in energy efficiency program delivery and resource acquisition, and we recognize that this Opportunity Report is a begining step in what will be an ongoing process of making energy more affordable for Rhode Island consumers, and keeping more of Rhode Island's energy dollars at home and at work in the state's economy.

III. Process

The Rhode Island Energy Efficiency and Resource Management Council issued a Request for Proposals in March 2008 to prepare a report to characterize and quantify the electric efficiency resources available in the state that are lower cost than supply. KEMA was selected to complete the energy efficiency and demand response portion of the Opportunity Report in April. The University of Rhode Island Partnership for Energy (URIPE) evaluated small scale renewable potential and NESCAUM, with Pace Energy, prepared a study on combined heat and power.

This Report is the first of two phases. In Phase I basic data were developed, input from key market players collected, overall analytic framework developed, and the magnitude of the potential estimated. In Phase II, the team will collect primary data to refine the analyses of

Phase I. This will be completed by the spring of 2009. This Phase I report is intended to be a resource for National Grid in the development of its Least Cost Efficiency Procurement and System Reliability Plans due to the Public Utilities Commission by September 1, 2008.

The detailed reports prepared by each of these organizations, KEMA, URIPE, and NESCAUM are attached to this Phase I Report. Vermont Energy Investment Corporation (VEIC) which partners with Optimal Energy was engaged by the EERMC to coordinate the process and prepare this Phase I Report as well as serve as a general program and policy consultant to the Council.

In consultation with National Grid and others, the VEIC team developed and distributed a comprehensive list of assumptions and inputs for use by the Contractors. These inputs included:

- National Grid Load Forecast (MWh, Peak MW, by class)
- Economic factors (discount rates, inflation)
- Planning Period (2009-2018)
- Avoided costs (values, DRIPE, externalities, etc.) based on the Synapse 2007 Study and Company information
- Line losses
- Rating Periods
- Emissions Factors

A consistent list of inputs is necessary to assure benefit and cost comparability across initiatives.

IV. Limits of the Report

Estimates of the energy efficiency potential in other areas have been conducted using a variety of methodologies. These studies have typically underestimated the cost-effective efficiency potential due to a variety of reasons. First and foremost is an inherent conservatism. These studies are often a critical piece of infrastructure planning. The traditional utility “obligation to serve” has often been a strong driver to assure that the savings are not over-stated. There are additional factors that contribute to understatement of the benefits of energy efficiency, as briefly noted below:

- Emerging and unidentified technologies may provide opportunities for savings that could not rationally be captured in the study.
- Energy costs rising faster than anticipated may significantly alter the benefit/cost analysis.
- Lower measure costs, from economies of scale or other market effects, may have a similar effect.
- Changes in delivery strategy, at the program or portfolio level may significantly alter the adoption rate of a specific measure or bundle of measures.

Experience has also shown that energy efficiency potential is not a fixed quantity. Steve Nadel of ACEEE presented an example of this in an illustration he offered of the energy efficiency potential available in New York at two different time frames, 1989 and 2003. After 14 years of active energy efficiency investment in the intervening years, the energy efficiency potential remained at an almost identical level. The technology for efficiency constantly increases through research and development of market actors. Just as you would not expect to buy a laptop computer in 1998 that could deliver the same value as a 2008 laptop, so too, does energy efficiency technology constantly mature and improve. As we race to invest in and procure low cost efficiency resources in 2009 more efficiency opportunities will emerge in 2010 due to technology advancements – and this process of efficiency advance and new low-cost resource opportunities will continue each year.

The VEIC team advises readers that the constraints on time and budget for this Phase I Report meets the requirements of law and the objectives outlined in the RFP with output to be improved and refined with more local primary data collection and Rhode Island onsite and phone survey work in Phase II. It is our recommendation that the EERMC as well as the PUC, General Assembly, OER, and National Grid and other stakeholders, treat these studies as laying the groundwork for ongoing and more detailed and precise analysis.

V. Energy Efficiency Potential

A. Research Objectives

KEMA's Phase I effort included:

- review of a set of recent potential studies;
- review of the results of RI programs over the last three years;
- data collection and interviews with a set of key market players;
- development of a measure list and initial screening;
- development of initial resources estimates.

KEMA's deliverables were a review of the other potential studies and suggested levels for the initial potential estimates (see KEMA Appendix A) and the initial measure list, screened measure list, and documentation (see KEMA Appendices A and B).

B. Findings

1. Potential

This study assesses the magnitude and cost of the energy-efficiency resource potential for saving electricity in Rhode Island. It calculates technical, economic, and achievable efficiency potential savings for 3 years and 10 years, and is restricted to measures and practices that are presently commercially available. The energy savings that KEMA found through low-cost efficiency are quite large and are measured in megawatt hours (MWh) and gigawatt hours (GWh).[1]

In terms of estimating the demand-side resource (efficiency and some demand response) potential under three different scenarios: technical, economic and achievable potential,[2] the following definitions are employed:

> **"Theoretical" Technical Potential:** Technical potential refers to the total demand-side resource potential over the planning period from all measures considered, regardless of whether those measures are cost effective, and without regard for market barriers or the ability of programs to capture it. This potential is defined as the additional savings over and above those expected to occur without efficiency program intervention.[3]
>
> **Economic Potential:** Economic potential refers to the total demand-side resource potential over the planning period from all measures that are cost effective, based on a total resource cost test (TRC). The TRC for instance uses the cost of efficiency resources as compared with the avoided electric consumption valued at the forecasted electric supply costs, as well as any other quantifiable benefits such as fossil fuel and water savings. Economic potential does not take into account market barriers nor the costs of market intervention. As such, it can be considered an upper bound of the opportunities available for capture with energy efficiency programs that target all cost-effective efficiency that is cheaper than supply consistent with the mandate of the 2006 Energy Act and Least Cost Procurement.
>
> **"Conventional" Achievable Potential:** Achievable potential refers to the estimated maximum demand-side resources that could be captured over the planning period, given aggressive, well designed, fully-funded programs. Achievable potential considers economic and other barriers to efficiency adoption, historic penetration rates from programs, and specific program strategies. As such, it provides an estimate of the portion of economic potential that may be expected to be captured with programs and assumed associated costs involved in capturing it. This estimate generally assumes traditional program approaches and consequently is a provisional first step but not definitive of what is actually achievable under RI law. This is because under Least Cost Procurement it is possible to leverage higher savings through bolstered marketing, financing, and community based delivery strategies.

In their analysis of Rhode Island, KEMA found a very large energy efficiency potential available at lower cost than supply. The table below summarizes their conclusions by showing the technical, economic, and achievable potential for energy savings in gigawatt hours.

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[1] A megawatt hour is equal to 1,000 kilowatt hours (or kWh). A gigawatt hour is equal to 1,000,000 kilowatt kWh.

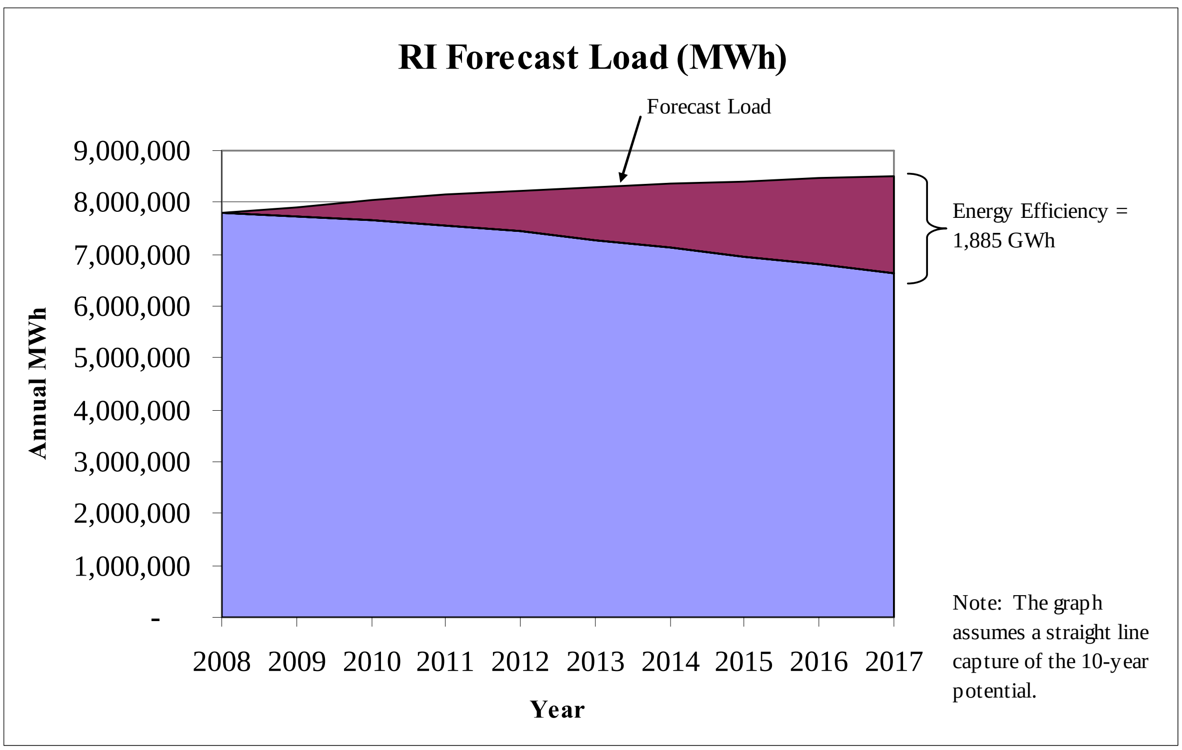
[2] Note, while all three analyses were performed for energy efficiency, demand response, CHP and small-scale renewables only estimated some of these metrics, depending on the specific resource. See the attached reports for more specific details.

[3] The base case forecast and technology penetrations include effects from autonomous efficiency improvements that would result from natural market shifts, existing and expected codes and standards.

Energy Efficiency Potential, 10-year (2009-2018)

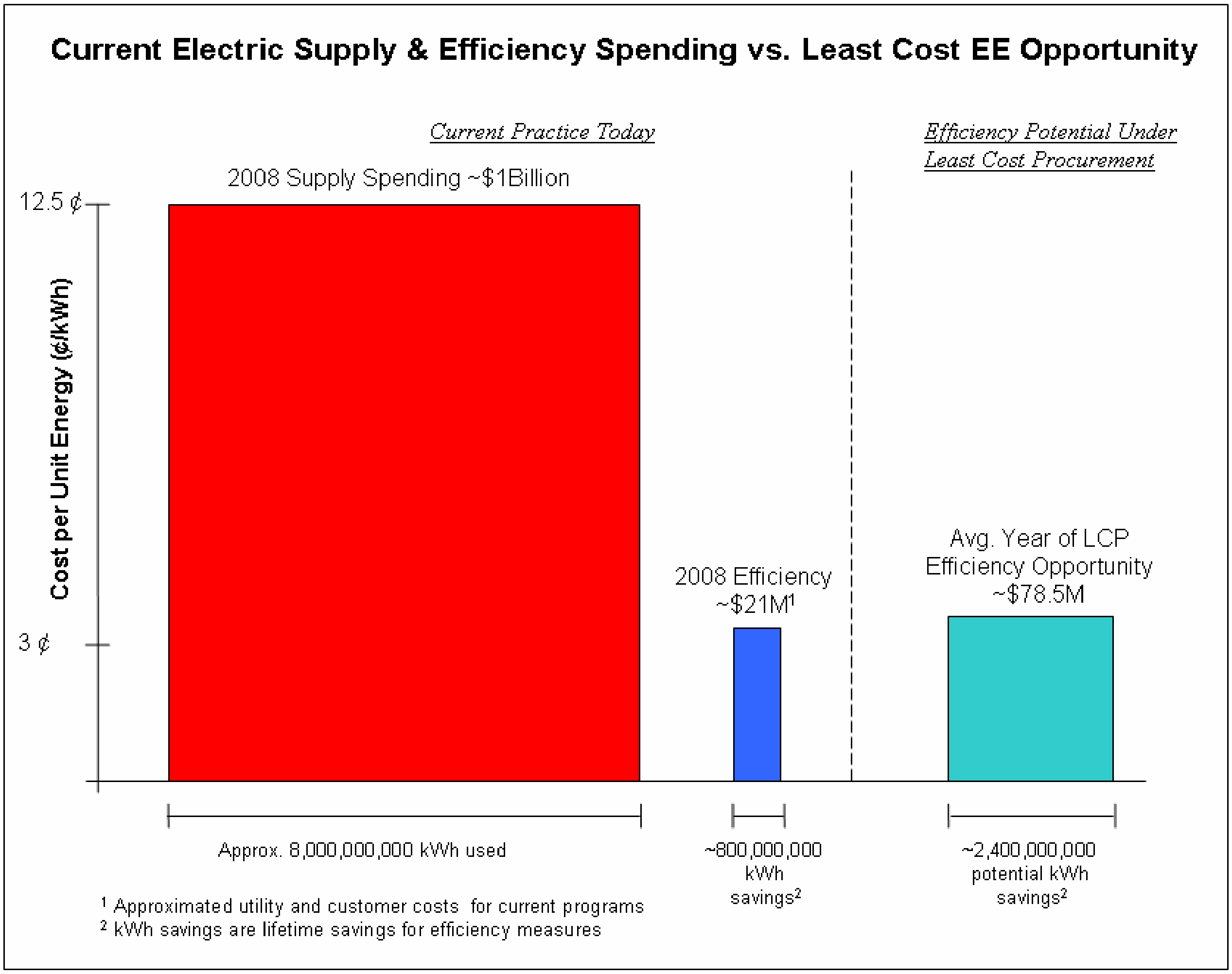
GWh	**"Theoretical" Technical Potential**		**Economic Potential**		**"Conventional" Achievable Potential[4 5]**		**Δ Economic – "Conventional" Achievable**	
	GWh	% of Forecast	**GWh**	**% of Forecast**	GWh	% of Forecast	GWh	% of Forecast
Residential	1,038	34%	**870**	**28%**	273	9%	597	19%
Commercial	1,161	32%	**1,026**	**28%**	371	10%	655	18%
Industrial	156	14%	**154**	**14%**	120	11%	34	3%
Overall	2,354	28%	**2,050**	**24%**	764	9%	1286	15%

The size of the economic efficiency potential relative to current and projected load is illustrated in the graph below. Through the acquisition of the low cost efficiency resources KEMA found it is possible to reduce total energy usage while growing the economy.

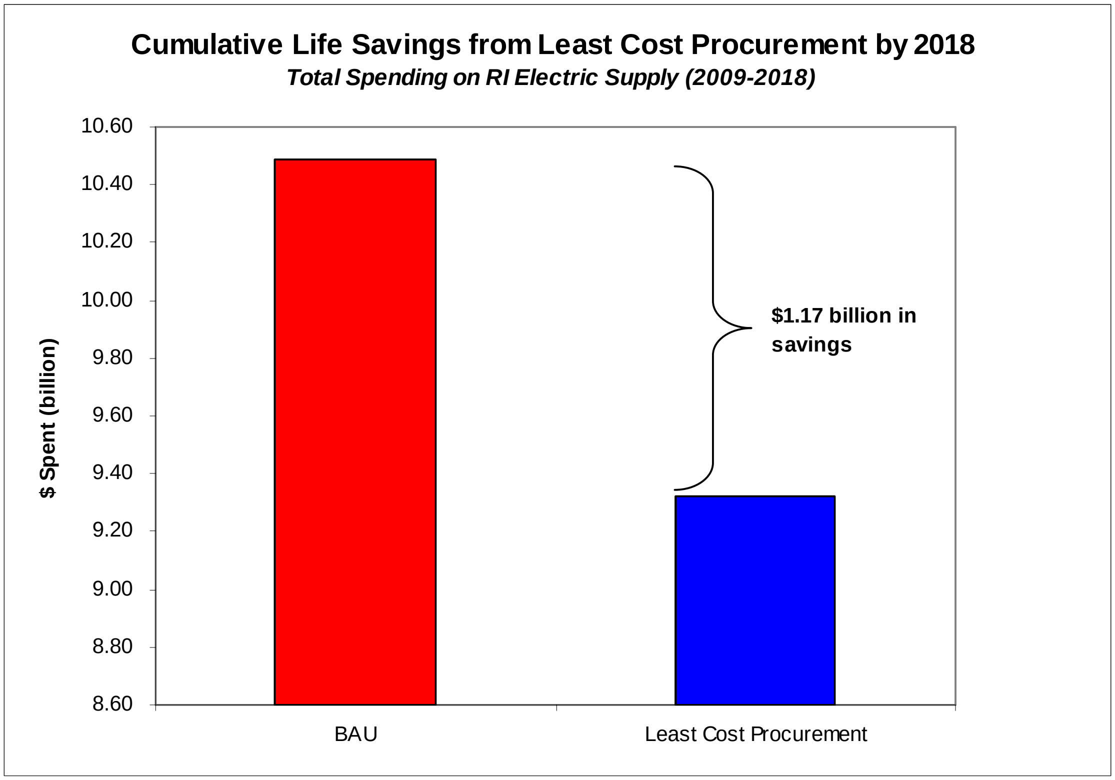


[4] This estimate generally assumes traditional program approaches. It is a provisional first step but not definitive of what is achievable under RI law because under Least Cost Procurement it is possible to leverage more savings through bolstered marketing, financing, and community based delivery strategies.
[5] Technical and economic potential does not include any reductions of savings for free riders by definition. Achievable potential reported here does include the reduction of savings from free riders.

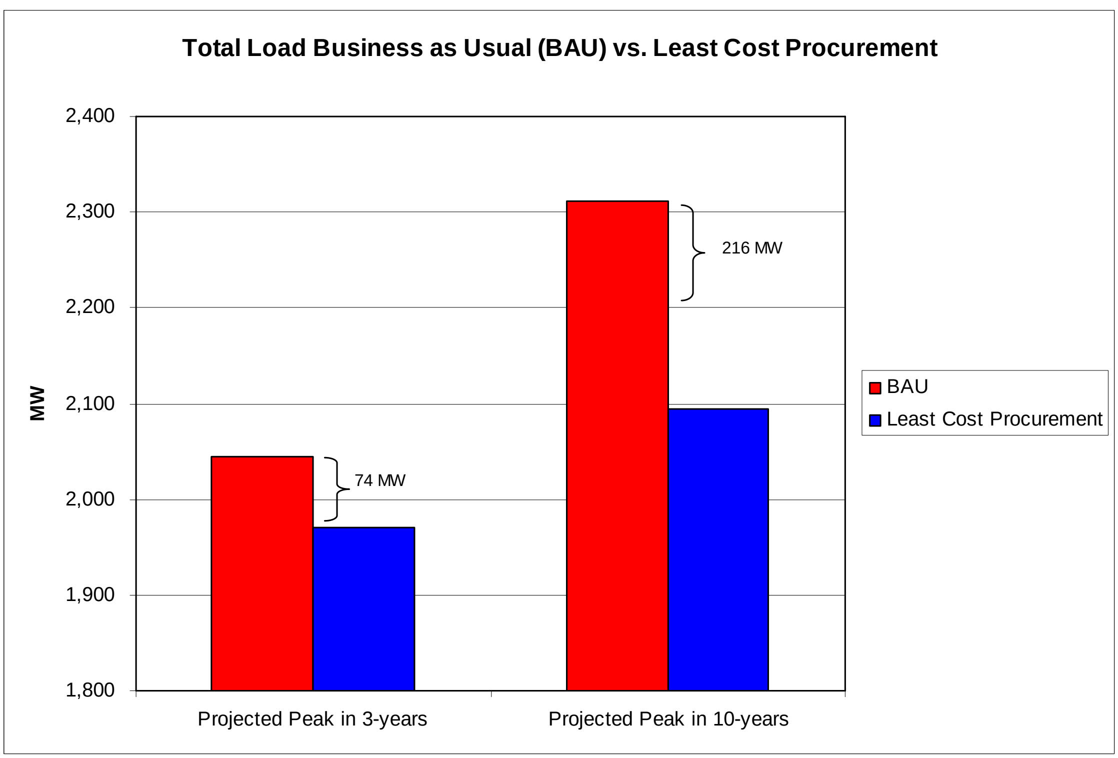
Over the 10 year time period of their study, KEMA found there exists is a very large, low cost economic efficiency potential. The graph below illustrates that in an average year from 2009 to 2018 there is approximately 2,400,000,000 kWh of efficiency resources available at a cost of just over 3¢/kWh, using the annual average savings from the economic potential. That is, the investment in low-cost efficiency resources could likely be quadrupled – to generate hundreds of millions of dollars in savings for ratepayers – and still remain much cheaper than the cost of electric supply.



In aggregate terms, KEMA found that the procurement of efficiency resources that are cheaper than supply would save Rhode Island ratepayers more than $1billion by 2018, as is illustrated in the following chart. This is an enormous untapped local Rhode Island energy resource and the process of procuring that resource would generate hundreds of non-utility jobs in the state.



In addition, the study found that the peak MW reduction impact of energy efficiency resources that are cheaper than supply is sizable as illustrated in the figure below.



KEMA also disaggregated the energy and capacity savings by sector and end-use, as shown in Appendix B.

2. Review of other potential studies

KEMA reviewed twelve recent potential studies. From this review they determined that the technical potential ranged around 30% for the residential and commercial sectors and around 20% for the industrial. KEMA also found that the economic potential was typically between 8% and 10% lower than the technical potential. Based on a subset of five studies they calculated the relationship between technical potential and achievable potential in the residential and commercial sectors at about 68% and the same ratio in the industrial sector at 76%. These findings validate the specific findings for Rhode Island.

3. RI Program Review

KEMA reviewed the Rhode Island programs against two major best practices studies and offered several recommendations for improvement. They noted that many of the RI offerings are currently included in these listings or similar to those listed, and that the cost per lifetime kWh of $0.021 “falls comfortably in this range” between $0.01/kWh and $0.05/kWh.

C. Potential Phase II Objectives

1. Refine program designs and budgets
2. Modeling of potential new measures & programs
3. Confirm or revise technical, economic and achievable potential estimates based on primary research including on-site energy audits of facilities to capture primary data on saturations and efficiency level of equipment existing today.

VI. Combined Heat and Power Potential

A. Research Objectives

NESCAUM developed estimates of the potential for CHP installation in Rhode Island based on the NE-MARKAL modeling program. The model includes inputs for CHP technical characteristics, RI Commercial and Industrial (C&I) demand and base case fuel consumption characteristics. They developed an estimate for RI based on scaling of the commercial sector potential study from Massachusetts. For the purposes of this study, NESCAUM only considered natural gas-fueled units.

The analysis includes environmental and economic impacts, as well as energy. NESCAUM performed sensitivity analyses on a variety of factors including natural gas and oil prices, the costs of CHP equipment, availability factors, and the cost of energy efficiency.

B. Findings

NESCAUM bounded the technical potential for CHP application by the year 2020 between 350 MW and 714 MW based on two different analytic approached. They developed a reference case for the year 2018 based on current rates of adoption in Massachusetts that put RI's cumulative CHP output at 141 MW.

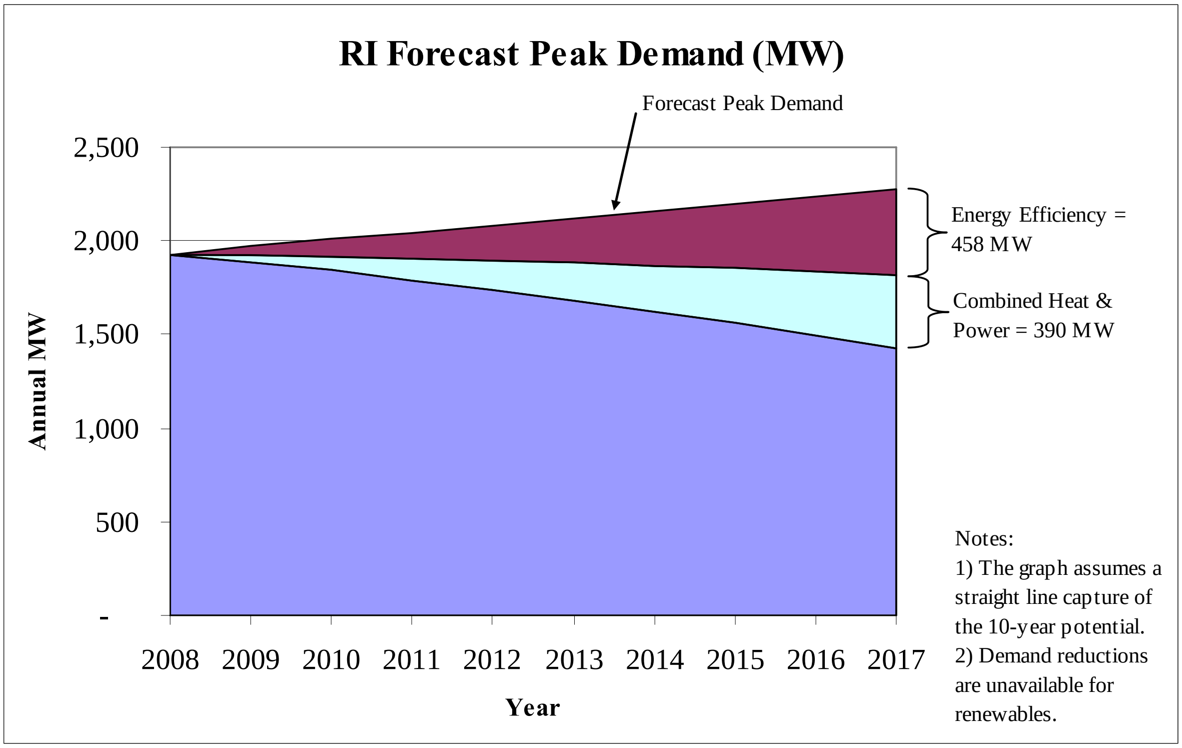
The analysis specifically adjusted for the following factors that influenced the economic and achievable potential of CHP:

- Whether gas is purchased at wholesale or retail
- The absence of specific back-up charges for electricity
- CHP system characteristics
- Natural gas prices
- Environmental requirements

NESCAUM developed estimates for both the high and low technical potential estimates based on variety of scenarios.

The economic potential for incremental CHP installations over the reference case through the study period is estimated to be 200 MW and 330 MW respectively for the low and high technical potential scenarios. NESCAUM's analysis of the impact of the policy initiatives showed adoption of the high technical potential at about three times the reference case for the FCM scenario and double that of the reference case in the absence of back-up charges.

Taken together, the number of MWs that can be procured through cost-effective energy efficiency identified by KEMA coupled with the number of MWs of CHP identified by NESCAUM is summarized in the chart below.



C. Potential Phase II Objectives

1. Refine the estimates of technical, economic, and achievable potential under a variety of policy and market scenarios
2. Develop program designs and budgets to promote the adoption of CHP in RI.
3. Develop benefit/cost analysis for program(s).
4. Refine policy recommendations for CHP support, e.g. allocation of FCM payments and back-up and stand-by tariffs.

VII. Renewable Energy Potential

A. Research Objectives

Investigators from URIPE analyzed the potential for non-utility scale renewable energy sources including solar, wind, biomass and small scale hydropower. This review included a high level review of the resource potential, *e.g.* the amount of the wind resource available on lands that do not have an inherent prohibition against its development. It also included an estimate of the applicability, *i.e.* the number of customers or sites where it would be economically feasible to install a renewable energy source.

B. Findings

The URIPE team found that small-scale renewable energy sources can contribute to meeting Rhode Island's need for energy and that the market for these technologies is currently underdeveloped in the state. The report estimated the raw potential of the following renewable resources as follows:

- Solar – The total solar irradiance that falls on RI during an average day in June or July is 16,977.6 GWh, compared to the state's annual energy usage of 7,888 GWh. The researcher estimates that 1% of the states area in solar panels would meet 65% of the state's energy needs.
- Wind – RI has on average the potential for 109 MW of small wind energy totaling one billion kilowatt hours per year.
- Small Hydropower – RI has 674 dams with an untapped potential of 11.5 MW.

The URIPE report discusses the technology, regulatory and market context of renewables in Rhode Island and provides guidance for additional research.

C. Potential Phase II Objectives

1. Refine estimates of renewable potential specifically including biomass and solar hot water technologies.
2. Develop program designs and budgets to promote renewable energy resources
3. Develop benefit/cost analysis

The Opportunity for Energy Efficiency that is Cheaper than Supply in Rhode Island

Phase I Report – Submitted July 15, 2008

Prepared by: KEMA, Inc.

Prepared for: Rhode Island Energy Efficiency and Resource Management Council

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1. Executive Summary

The Rhode Island Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 placed a requirement on the distribution utility to procure all energy efficiency that is less costly than supply. To help determine the quantity of such efficiency resources and the cost savings to be enjoyed by Rhode Island ratepayers, the General Assembly charged the Energy Efficiency and Resources Management Council (EERMC) with producing an Opportunity Report to identify the resource. This study was commissioned by the EERMC to meet this goal and accordingly estimates the size of the potential for energy and peak-demand savings from energy-efficiency measures in Rhode Island over the mid-term (3 years) and the long-term (10 years) that are cheaper than supply. This study demonstrates that significant additional and long-lasting cost-effective efficiency resources exist within the state, which can be procured by the distribution utility to save Rhode Island ratepayers money. This study also identifies a limited number of demand response type resources and measures including direct load control, displays, and storage cooling.

1.1 Study Scope – Energy Efficiency

This study assesses the magnitude and cost of the energy-efficiency resource potential for saving electricity in Rhode Island. It calculates technical, economic, and achievable efficiency potential savings for 3 years and 10 years, and is restricted to measures and practices that are presently commercially available. These energy savings through efficiency are quite large and low-cost and are measured in megawatt hours (MWh) and gigawatt hours (GWh).[1]

1.2 Key Findings

This study estimates the potential for cost-effective energy (MWh or GWh) and peak-demand savings (MW) from cost-effective energy-efficiency measures, over the mid-term and the long-term.

[1] A megawatt hour is equal to 1,000 kilowatt hours (or kWh). A gigawatt hour is equal to 1,000,000 kilowatt kWh.

1.2.1 Electricity Peak-Demand Savings

If all the *technically* feasible energy-conservation measures analyzed in this study were implemented regardless of economics, the overall technical peak-demand savings could amount to some 614 mw. If, however, only the measures that are *economic* (i.e., cost-effective when compared to supply-side alternatives) were implemented, potential peak-demand savings would be roughly 457 MW, 25 percent lower than the technically feasible amount. The residential sector contributes the most to both technical and economic savings potential, followed by the commercial sector (See Figure 1-1 below). To capture all of the economic potential would require that all economically feasible measures which are lower cost than supply be installed. This would mean for example that in the case of the deployment of compact fluorescent light bulbs – an efficiency resource demonstrated to be cheaper than supply – that all incandescent light bulbs in Rhode Island be replaced by a compact fluorescent bulb.

While this represents the economic efficiency potential, for a variety of reasons this entire low-cost efficiency resource cannot be procured by the distribution utility. For that reason in order to provide reasonable estimates of potential savings from least cost energy efficiency procurement we develop estimates of achievable potential which are based on conventional assumptions of measure adoption and are based on assumptions about possible program offerings. This generally assumes traditional program approaches and consequently is a provisional first step but not definitive of what is actually achievable under RI law. This is because under Least Cost Procurement, it is possible to leverage higher savings through bolstered marketing, financing, and community-based delivery strategies.

Technical Potential Findings:

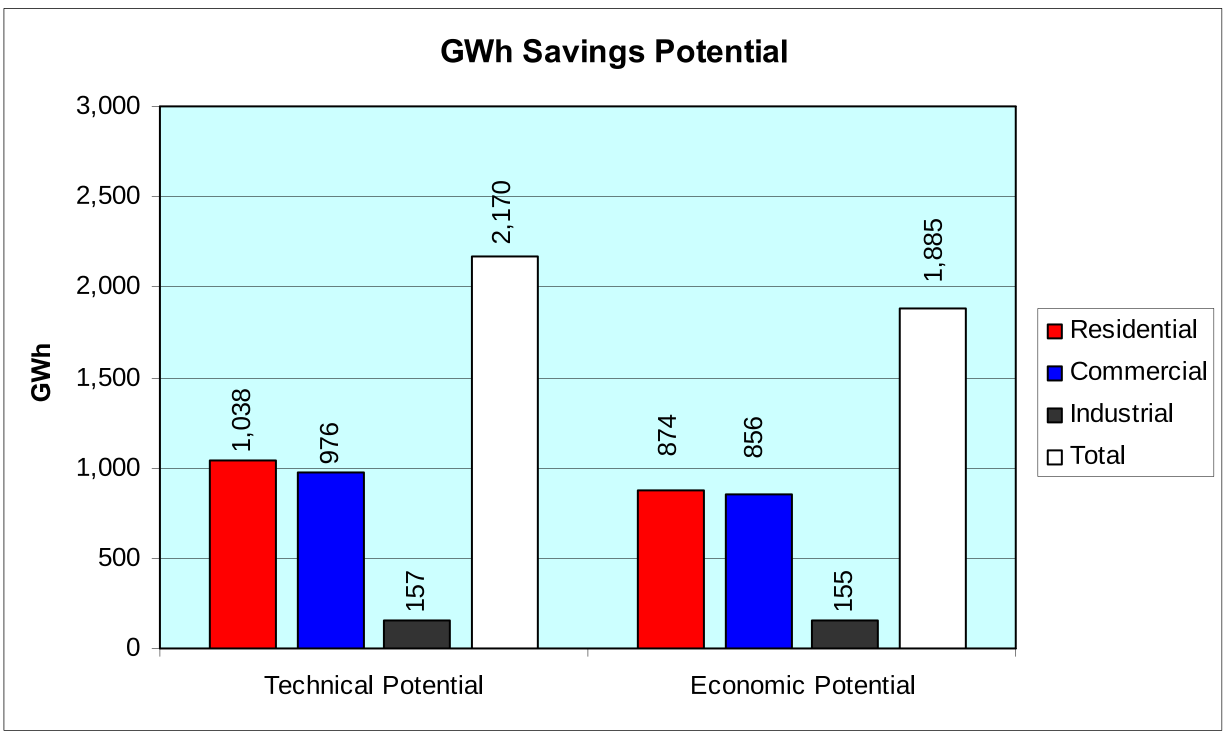
We estimated technical and economic potential for energy efficiency using KEMA's Demand Side Assyst model. In our this approach, we first estimate **technical potential** for energy savings by integrating key measure and market segment parameters using the following equation:

$$\begin{array}{c}\text{Technical}\\\text{Potential of}\\\text{Efficient}\\\text{Measure}\end{array} = \begin{array}{c}\text{Total}\\\text{sq. ft. or}\\\text{\# of}\\\text{Dwellings}\end{array} \times \begin{array}{l}\text{Base Case}\\\text{Equipment}\\\text{EUI or UEC}\end{array} \times \begin{array}{c}\text{Applicability}\\\text{Factor}\end{array} \times \begin{array}{c}\text{Not}\\\text{Complete}\\\text{Factor}\end{array} \times \begin{array}{c}\text{Feasibility}\\\text{Factor}\end{array} \times \begin{array}{c}\text{Savings}\\\text{Factor}\end{array}$$

We then assess **economic potential** by first developing a supply-curve analysis. This analysis eliminates double counting of measure savings. On a market segment and end-use/technology basis, measures are stacked in order of cost effectiveness, and the energy consumption of the system being affected by the efficiency measures goes down as each measure is applied. As a result, the savings attributable to each subsequent measure decrease if the measures are interactive. After eliminating double counting of savings, the benefits and costs associated with a given measure and market segment are compared using the Total Resource Cost (TRC) Test. The TRC Test is the ratio between the benefits of an efficiency measure and the cost of the efficiency measure including benefits and costs that accrue to ratepayers, the utility, and society. If the TRC is greater than 1.0, then the benefits (savings) of the efficiency resource are greater than the costs and the resource is cheaper than supply and should be procured pursuant to the Comprehensive Act of 2006 and the PUC's Standards for Energy Efficiency and System Reliability Procurement approved at the June 12, 2008 Open Meeting. The following figures illustrate the magnitude of the cumulative amount of efficiency resources that are cheaper than supply in Rhode Island (TRC >1.0) – depicted as the economic potential.

Figure 1-1 presents a summary of the technical potential and economic potential (efficiency resources that are cheaper than supply) in GWh for Rhode Island.

Figure 1-1



The Phase I study identifies more than 2,100 GWh of technical potential and more than 1,800 GWh of energy efficiency resources that are cheaper than supply in Rhode Island. This compares to an estimated total sales volume of roughly 8,000 GWh in Rhode Island in 2008. Figure 1-2 presents the GWh technical potential efficiency savings as a percent of total energy use for that sector.

Figure 1-2

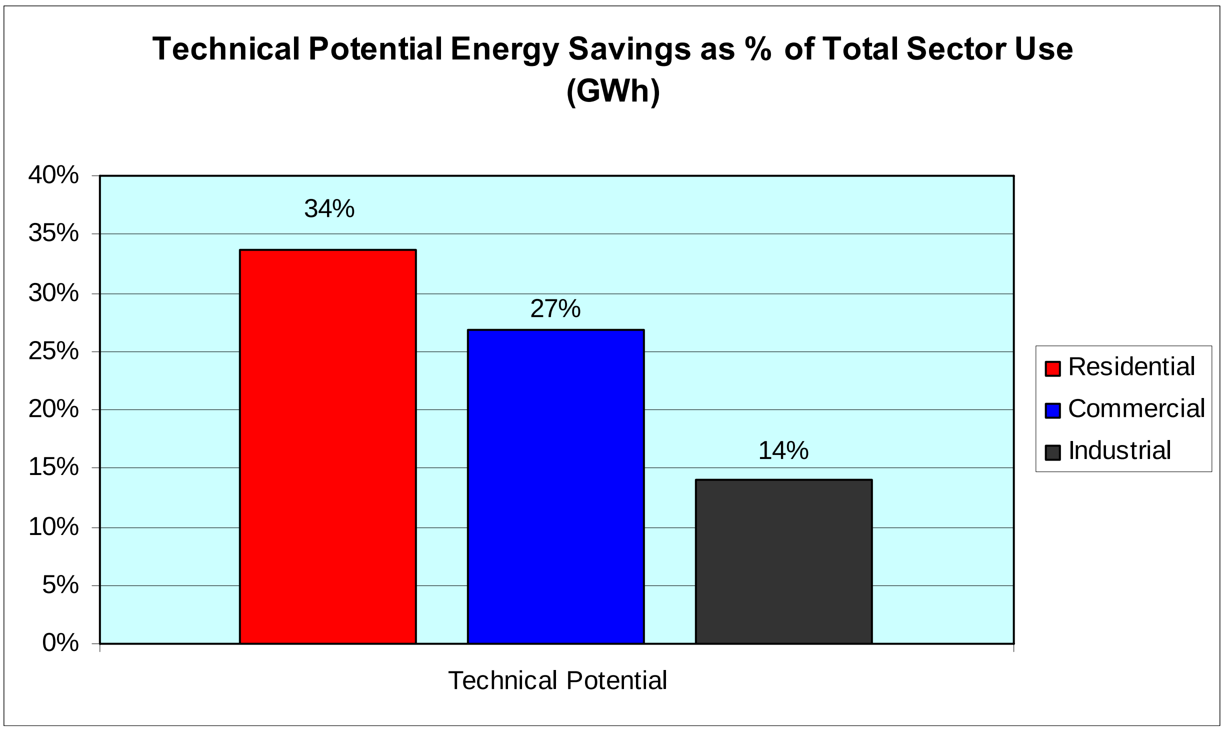
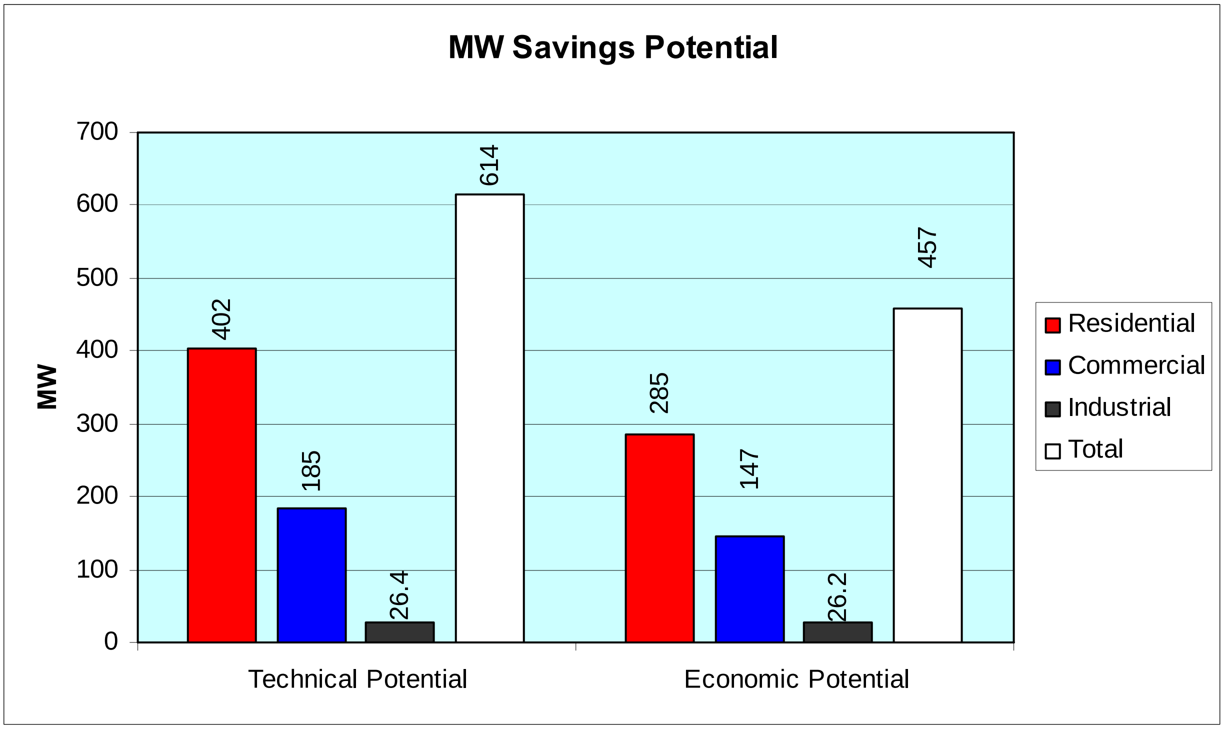


Figure 1-3 presents a summary of the technical potential and economic potential (efficiency resources that are cheaper than supply) in MW, or energy capacity, for Rhode Island.

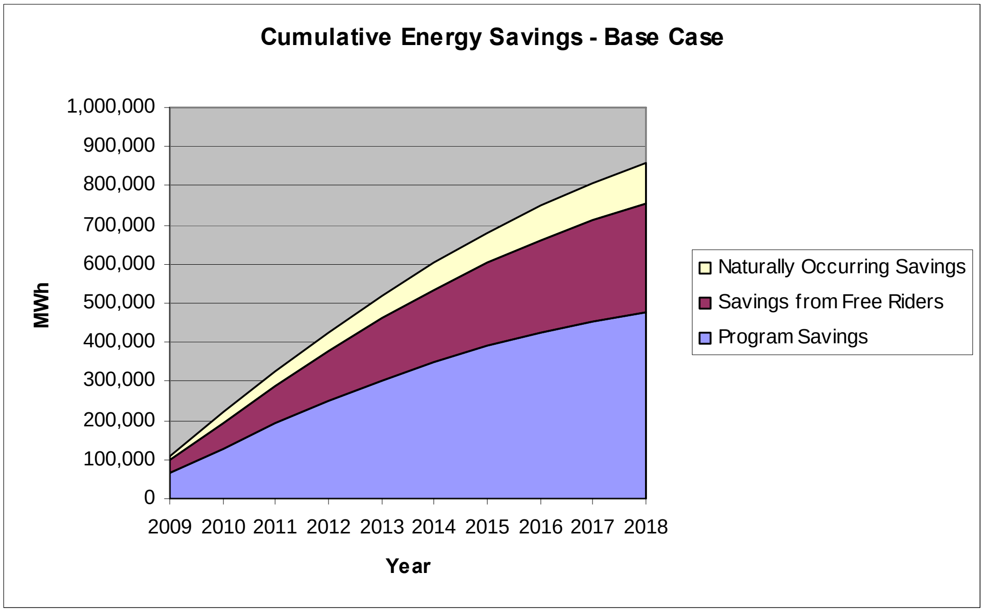
Figure 1-3

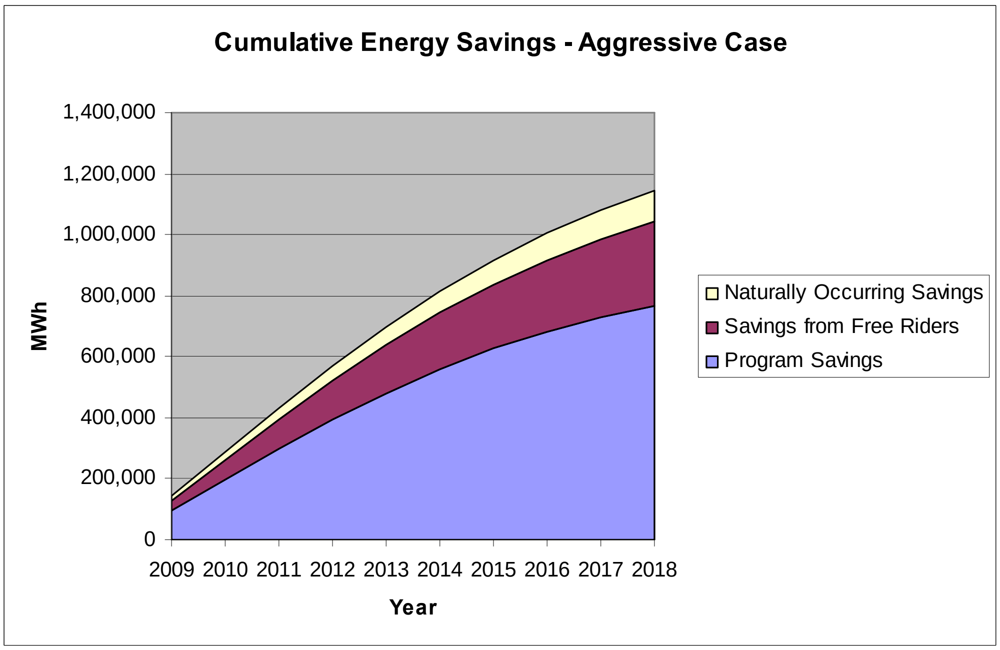


Achievable Potential

Achievable Potential is defined as the amount of potential that can be estimated from procurement and programmatic activity in the market. Namely it is an estimate of savings that will occur though efficiency procurement and program activity. Achievable potential can be calculated in several ways - some researchers calculate it as a fixed percentage of technical or economic potential; while others take a more nuanced more modeling approach, which is what was done here. Achievable potential is sometimes presented in MWh and MW per year over time. We calculated two scenarios of achievable potential – the Base Case – which is based on a funding level for energy efficiency that is comparable to 2008 and an Aggressive Case that is based on higher funding to go after cost-effective energy efficiency. The energy savings over time for these two cases are presented in Figure 1-4. The aggressive scenario is somewhat less cost effective than the base case as free ridership grows significantly over time. These are both presented here showing net savings, savings from free riders and savings from naturally occurring. Net savings plus savings from free riders is typically referred to as gross savings. It is important to note that the Aggressive Case still generally assumes traditional program approaches and consequently is a provisional first step and not definitive of what is actually achievable under RI law as under Least Cost Procurement, higher savings are possible through enhanced marketing, financing, and community-based delivery strategies

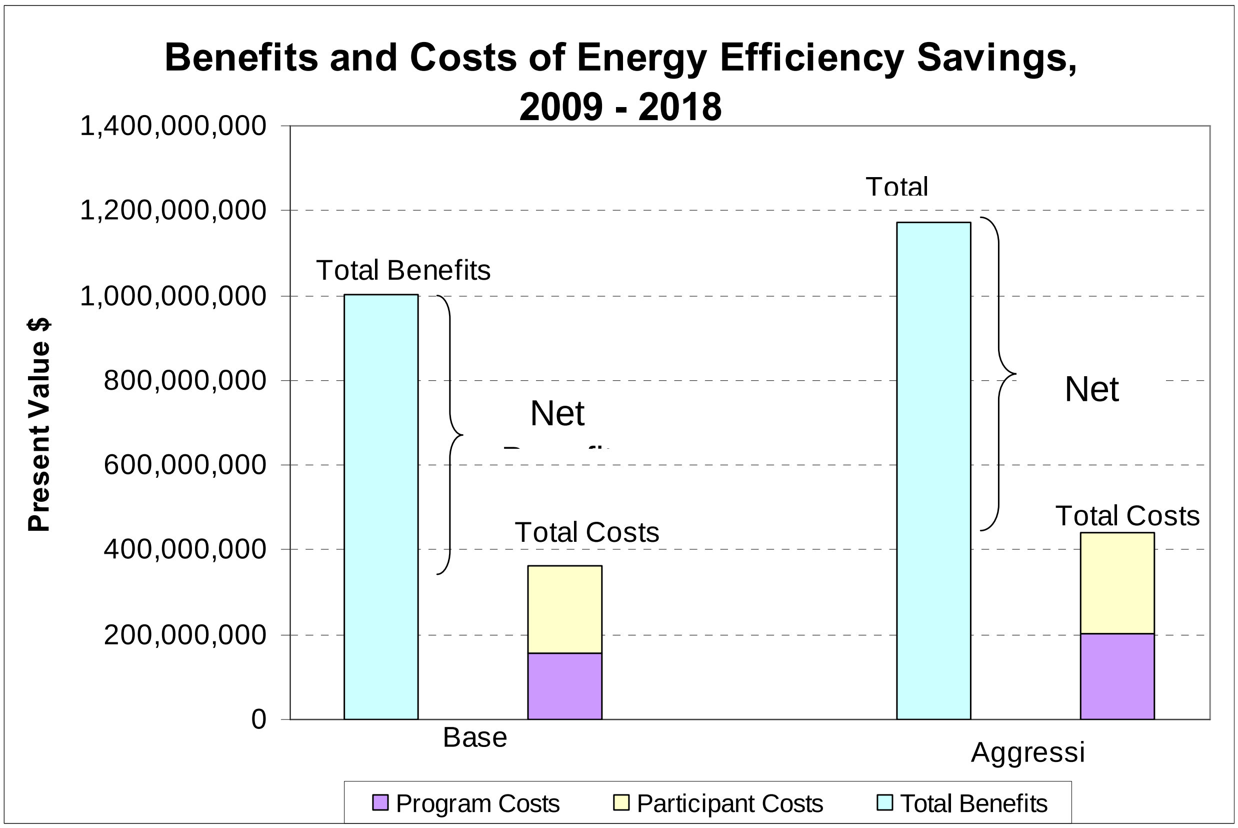
Figure 1-4
Cumulative Energy Savings





The overall cost effectiveness of the achievable potential is shown in Figure 1-5. This is compares the total benefits of the efficiency resource (primarily avoided supply costs, etc.) with the total cost (utility program cost + customer participant cost). It illustrates that the economic benefits of the efficiency measures far exceed their total costs, generating a net benefit to Rhode Island ratepayers.

Figure 1-5
Overall Cost Effectiveness



The Achievable Base Case is presented in a Table Format for years 2009, 2010, 2011 and 2018 in Table 1-1 below. As part of this chart we also present budgets for programs that we did not model within Demand Side Assyst, namely direct load control and an initial scope of an appliance recycling program.

Table 1-1
Summary of Base Case

Total Base Case				
Year - Program Costs-Real	2009	2010	2011	2018
Administration	$2,802,900	$2,745,254	$2,727,928	$2,329,631
Marketing	$224,130	$226,549	$228,995	$246,869
Incentives	$14,511,803	$14,883,210	$14,816,530	$10,113,325
Total	$17,538,833	$17,855,014	$17,773,453	$12,689,825
Net Energy Savings - GWh	64	129	192	478
Net Peak Electricity Demand Savings - kW	12,584	25,335	37,756	101,474
Annual Participant Costs (Real)	$23,964,484	$23,931,306	$23,318,488	$13,765,174
Annual PV Participant Costs	$23,964,484	$23,689,528	$22,849,696	$12,562,957
Naturally Occurring and Free Rider Energy Savings Total (Annual)	46	45	44	29
Accumulated Naturally Occurring and FR Energy Savings Total (Annual)	46	91	135	381
Naturally Occurring Peak and FR Demand Savings Total (Annual)	5916	5812	5683	4048
Accumulated Naturally Occurring adn FR Peak Demand Savings Total (Annual)	5916	11728	17411	51061
PV Avoided Costs	$128,028,039	$125,430,954	$115,221,818	$39,173,449
PV Program Costs	$17,538,833	$17,674,625	$17,416,138	$11,581,527
Annual TRC	3.08	3.03	2.86	1.62
Program Lifetime cents/kwh for that year	0.022	0.022	0.023	0.044
Additional Programs- Budget				
Appliance Recycling	1053000	1053000	1053000	1053000
Direct Load Control	$650,000	$1,040,000	$1,210,564	$871,643
Total National Grid Budget	$19,241,833	$19,948,014	$20,037,017	$14,614,468

Our model has two embedded assumptions. First, once a measure is replaced, it is assumed to be efficient for the rest of the period. Second, in this phase we are not adding any new potential technologies that may become available during the course of this assessment. In both the Base Case and the Aggressive Case as we have modeled them, after 2015 most of the efficient retrofit measures have already been installed either through the program or by non-participants.

The Aggressive Achievable Case is presented for years 2009, 2010, 2011 and 2018 is presented in Table 1-2. Note that in 2011 with an efficiency program size of $40 million (nearly a 250% increase from today's level of $16 million) the TRC is still 2.62. That is, at that level of increased efficiency procurement, the economic benefits still greater out weigh the costs – by a factor of 2.6 to 1.

Table 1-2
Summary of the Aggressive Case

Total Aggressive Case				
Year	2009	2010	2011	2018
Administration	$2,802,900	$2,903,567	$3,043,299	$3,383,523
Marketing	$224,130	$350,716	$536,788	$1,553,784
Incentives	$36,484,938	$35,791,471	$37,013,212	$30,152,741
Total	$39,511,968	$39,045,754	$40,593,299	$35,090,048
Net Energy Savings - GWh	96	197	296	764
Net Peak Electricity Demand Savings - kW	24,136	49,089	74,088	216,392
Annual Participant Costs (Real)	$3,081,765	$3,017,751	$2,840,478	$1,162,571
Annual PV Participant Costs	$3,081,765	$2,987,263	$2,783,373	$1,061,035
Naturally Occurring Energy Savings Total (Annual)	3	3	3	3
Accumulated Naturally Occurring Energy Savings Total (Annual)	46	91	135	381
Naturally Occurring Peak Demand Savings Total (Annual)	5,916	5,812	5,683	4,048
Accumulated Naturally Occurring Peak Demand Savings Total (Annual)	5,916	11,728	17,411	51,061
PV Avoided Costs	$204,221,811	$208,762,089	$203,937,187	$104,547,662
PV Program Costs	$39,094,273	$41,201,037	$42,159,336	$32,963,094
Annual TRC	2.74	2.70	2.62	1.88
Program costs/ lifetime kwh for program year	$0.03	$0.03	$0.03	$0.08

Additional Programs presented in Base Case not presented here

1.3 New Program and Measure Areas:

As part of this study we also identified new opportunities for energy efficiency for Rhode Island. This was based on 4 tasks:

1) A review of Rhode Island's programs compared to best practice programs
2) A review of Rhode Island's programs compared to other state portfolios
3) Interviews with Rhode Island market actors; and
4) A review of Rhode Island measures compared to KEMA's master list

Our review of other portfolios as indicated in the Section 5 indicated the following potential new program areas for Rhode Island – they are characterized as short and long term opportunities;

- Adding an appliance recycling program (residential) – Short Term
- Adding a retro commissioning program (commercial/ industrial) – Short Term
- Direct ties to LEED – Long Term

- Adding a data center program – Long Term
- Adding a direct load control program – Short Term
- Performance based lighting program – Long Term

We also identified new potential measures that may be applicable in 2-5 years. This list was developed from a review of emerging technologies from ACEEE, LBL and other utilities. We list them here for consideration and plan to model them in Phase II.

- LED's
- Cool roofs
- Commissioning
- Smart AC
- EnergyStar or Better PC
- EnergyStar or Better TV
- EnergyStar or Better Set-Top
- Heat pump dryer
- Solar hot water heating

Potential new Commercial / Industrial Measures

- LED's (residential and C/I)
- Cool roofs
- Commissioning
- Energy recovery ventilation
- Smart AC
- LED Downlights
- Induction Lighting
- CDMi replacement for incandescent or halogen reflector lamps
- Data center package

At a conceptual level, there are three sources, or reservoirs, of efficiency resources that are cheaper than supply that can be procured by the utility in accordance with the 2006 Comprehensive Energy Act and the PUC's Standards for Energy Efficiency and System

Reliability Procurement LCP and SR Standards to generate large savings for Rhode Island ratepayers. These are:

1) **Existing Efficiency Measures and Resources** pursued by the utility today that have a TRC greater than 1.0 but have been underinvested in and not tapped for all cost savings.

2) **New Efficiency Measures and Resources** that are *not* currently pursued by the utility efficiency programs but have a demonstrated TRC greater than 1.0 so they would generate cost savings.

3) **New Approaches to Existing Efficiency Measures and Resources** that would enable a greater quantity of resource to be tapped with TRC greater than 1.0 and thus generate cost savings.

Figure 1-6 provide examples of the above opportunities into those 3 categories.

Figure 1-6
Three Categories of New Opportunities

- *Existing Efficiency Measures and Resources (pursued today)* – A key basis for the expansion of efficiency resource procurement is existing programs and measures that have a large cost-effective potential remaining.

- *New Efficiency Measures and Resources* – Piloting and initiating new cost effective measures such as solar water heaters, an appliance recycling program, a direct load control program for mass market customers, and new technologies such LEDs that are *not* currently pursued by the utility.

- *New Approaches to Existing Efficiency Measures and Resources* **–** New program concepts such as zero emission homes, additional marketing, creative use of financing, increased use of retro commissioning, and community-based delivery of energy efficiency.

1.4 Comparison to Supply Side Resources and Net Benefits

The figures presented in this section provide additional data related to using energy efficiency as part of a least cost procurement strategy.

Figure 1-7 compares the average cost of supply with the average cost of energy efficiency over study period. This figure illustrates how much less expensive energy efficiency is than electric supply – 3¢/kWh vs. 12.5¢/kWh.

Figure 1-7
Electric Supply vs. Efficiency Costs

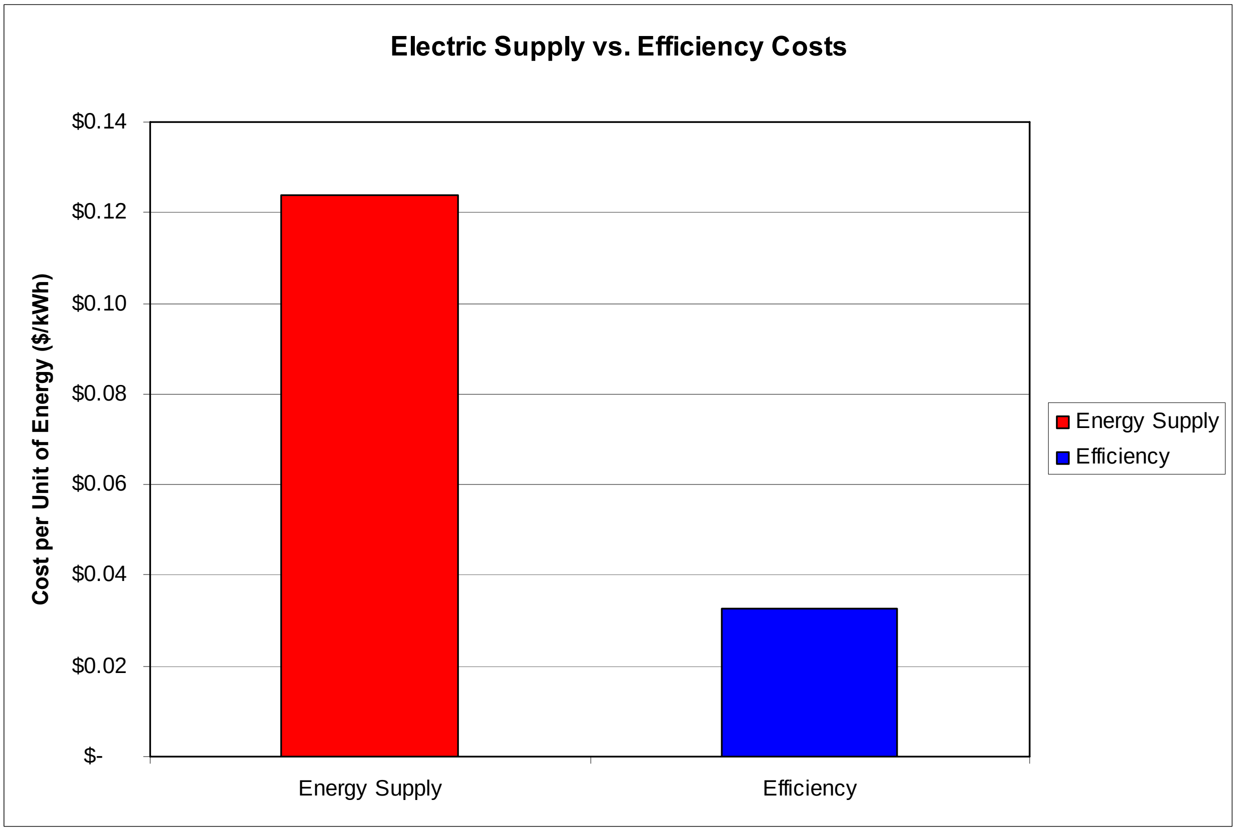
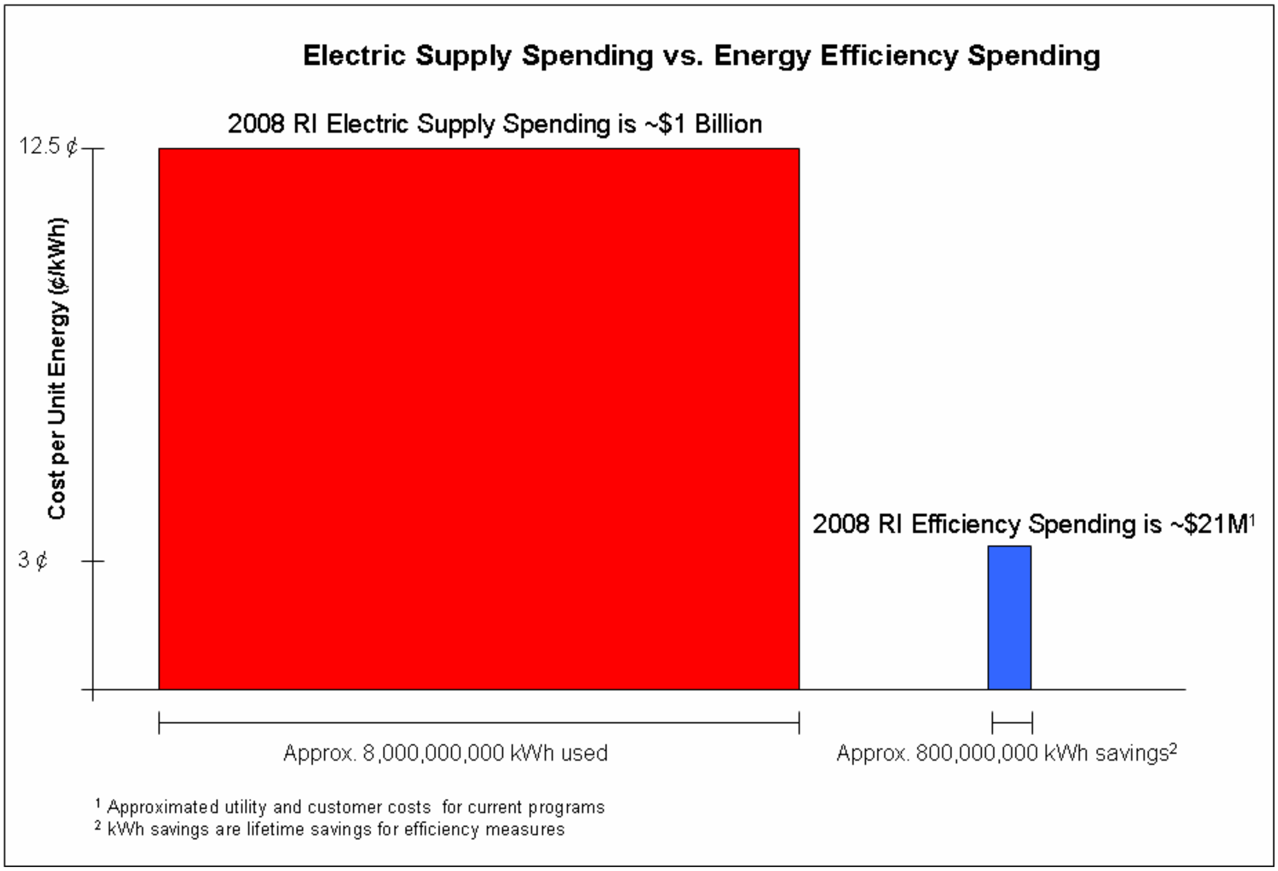


Figure 1-8 illustrates how the 2008 status quo of spending is heavily weighted toward higher cost supply – resulting in hundred of millions dollars in unwarranted energy costs for Rhode Island ratepayers. This is an imbalance in resource acquisition and the strong opportunity exists for National Grid to remedy this imbalance through its 2009-2012 Energy Efficiency Procurement Plan. We found there is ample additional low cost efficiency ready to be procured.

The goal of the Plans will be to ensure that Rhode Island ratepayers no longer spend so much for high cost electric supply when less expensive efficiency resources are available in the state.

Figure 1-8
Electric Supply Spending vs. Energy Efficiency Spending



Our findings indicate there is a very large energy efficiency potential available that is cheaper than electric supply. The results of our study are summarized in Figure 1-9 which lists the technical, economic, and achievable potential for energy savings in gigawatt hours. It is important to note that the achievable Assumes traditional program approaches and is a provisional first step and not definitive of what is achievable under RI law. Under Least Cost Procurement larger savings may be achieved via bolstered marketing, financing, and community based delivery strategies.

Figure 1-9
Energy Efficiency Potential, 10-year (2009-2018)

GWh	Technical Potential		Economic Potential		"Conventional" Achievable Potential[2][3]		Δ Econ – "Convent."	
	GWh	% of Forecast	**GWh**	**% of Forecast**	GWh	% of Forecast	GWh	% of Forecast
Residential	1,038	34%	**870**	**28%**	273	9%	597	19%
Commercial	1,161	32%	**1,026**	**28%**	371	10%	655	18%
Industrial	156	14%	**154**	**14%**	120	11%	34	3%
Overall	2,354	28%	**2,050**	**24%**	764	9%	1286	15%

Figure 1-10 shows the big economic efficiency potential that's much cheaper than supply by presenting the potential savings that illustratively would occur if all the economic potential were achieved in a 10 year period.

[2] This estimate generally assumes traditional program approaches. It is a provisional first step but not definitive of what is achievable under RI law because under Least Cost Procurement it is possible to leverage more savings through bolstered marketing, financing, and community based delivery strategies.

[3] Technical and economic potential does not include any reductions of savings for free riders by definition. Achievable potential reported here does include the reduction of savings from free riders.

Figure 1-10
Current Electric Supply & Efficiency Sending vs. Least Cost Efficiency Opportunity

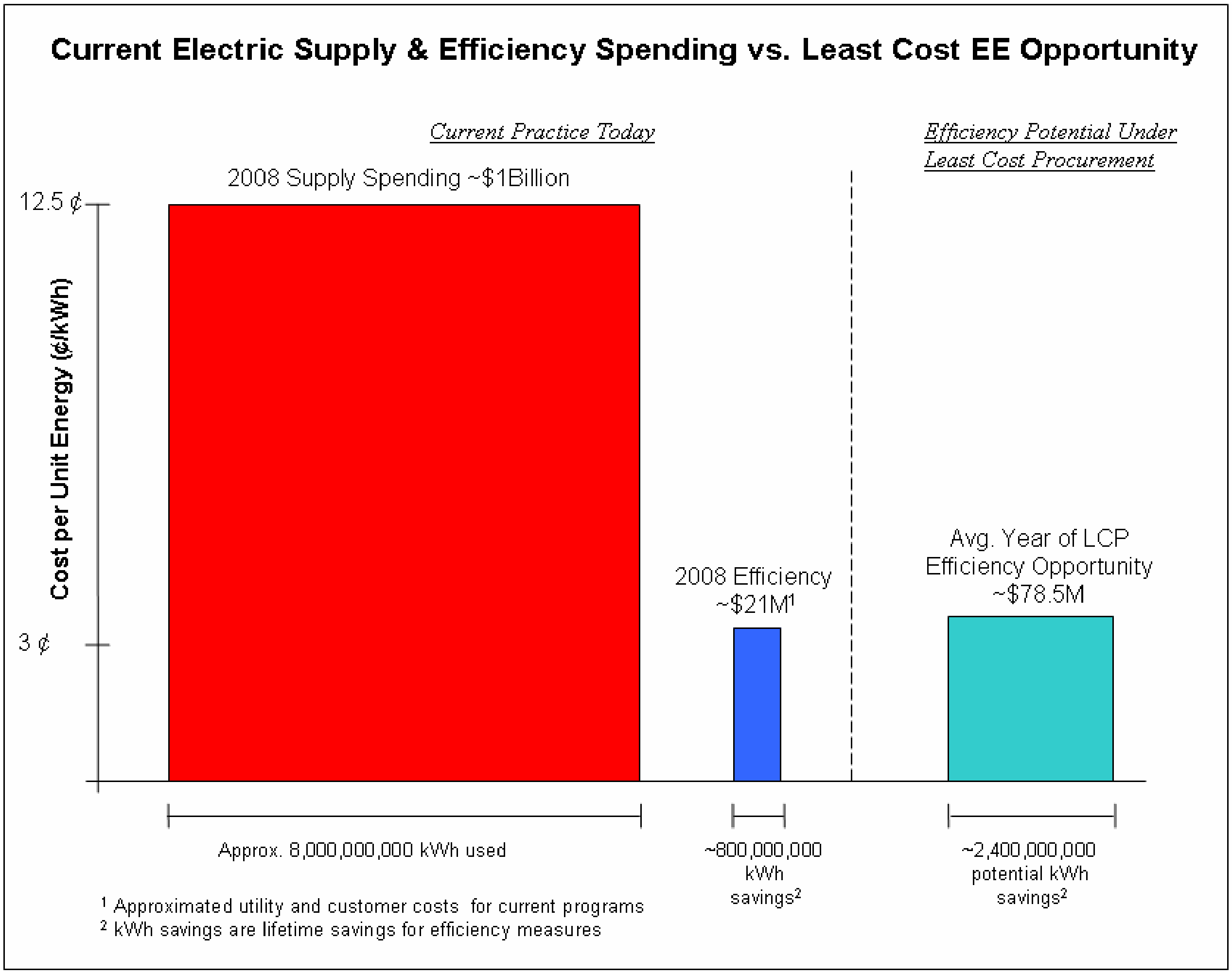


Figure 1-10 illustrates that the investment in low-cost efficiency resources could be significantly increased – to generate hundreds of millions of dollars in savings for ratepayers – and still remain much cheaper than the cost of electric supply. Using the annual average savings from the economic potential, from 2009-2018 we found there is roughly 2,400,000,000 kWh of approximately 3.2¢/kWh efficiency resources available. [4] [5]

We quantified the amount of aggregate savings that could be secured for Rhode Island ratepayers through Least Cost Procurement by 2018 in Figure 1-11 finding more than $1 billion in savings available in Rhode Island during that time.

[4] The overall costs for energy efficiency presented in Figure 1-10 were developed as follows: 1) the second bar is based on actual program costs in 2008 and includes all utility program costs (such as administration and marketing as well as carryover from the previous year) and does not include any customer costs; 2) the costs in the third bar are based on the customer costs of installing all the measures identified in the economic case and do not include any utility program costs. This calculation is presented in the next footnote.

[5] The 2,400,000,000 kWh savings number is derived as the 10 year economic potential (2,050,000) times a measure life of 12 for lifetime kWh of 24,600,000,000. Annualized over 10 year produces annual savings of 2,460,000,000 which when multiplied by 3.2 cents per kwh yields 10 year economic spending of $787,200,000. The annual equivalent of that number is $78,720,000. As noted above these costs are just the costs for the measures installed – no program costs are included.

Figure 1-11
Cumulative Lifetime Savings from Least Cost Procurement by 2018

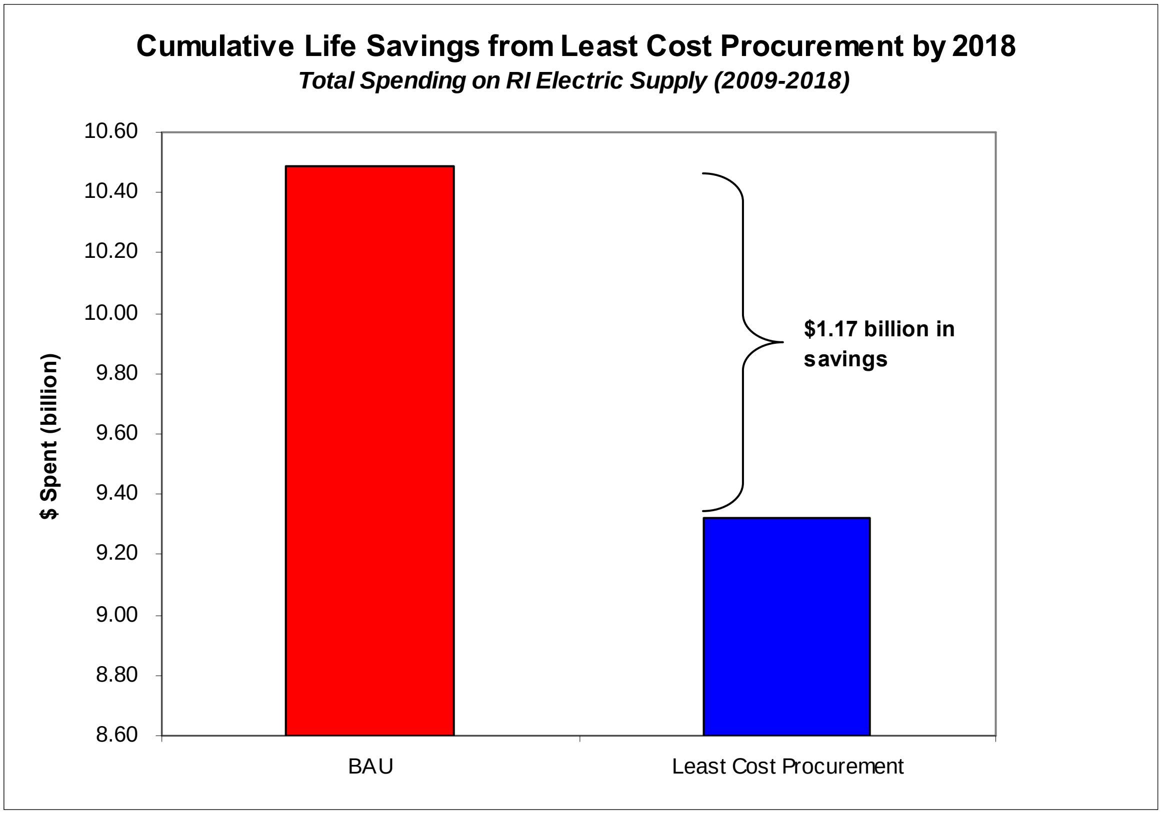
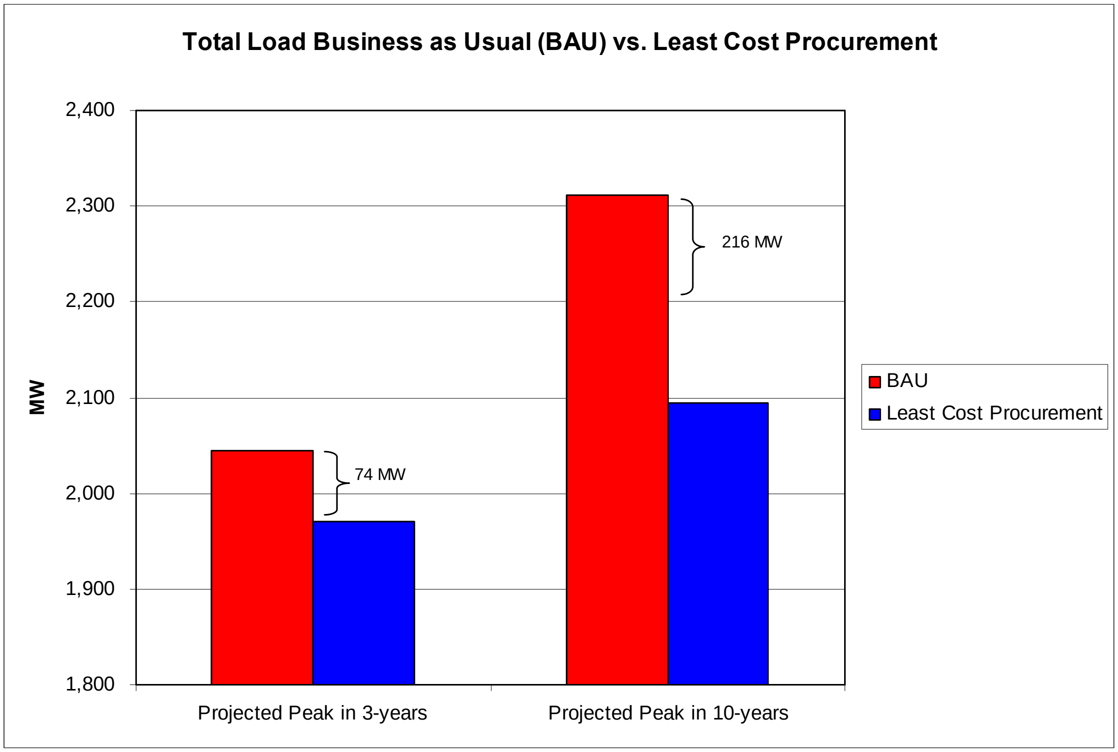


Figure 1-12 presents the impact of using least cost procurement on the peak both at three years and 10 years. As this figure illustrates the peak is reduced by over 216 MW over 10 years.

Figure 1-12
Electric Supply Spending vs. Efficiency Spending



2. Introduction

This report summarizes the findings of the first phase of the Rhode Island Energy Efficiency Opportunities project. This report is organized in the following manner:

1) Executive Summary
2) Introduction
3) Methodology
4) Review of other potential studies
5) Program and measure review
6) Initial estimates of potential and supply curves
7) Key Assumptions
8) Estimates of program savings for potential new programs

The results presented in this report indicate there is a large, untapped efficiency resource that is cheaper than supply in all ratepayer sectors in Rhode Island. In addition to quantifying the magnitude of this low cost resource, this report also identifies some potential new program areas and new measures to be considered more carefully in the Utilities Procurement and Program Plans and in Phase II of this analysis.

3. Methodology

Our original proposed methodology for this study given the time frame was:

1) Review of other potential studies
2) Data collection and interviews
3) Program review
4) Development of initial technical data on measures
5) Initial measure list

In addition to our proposed methodology we developed initial estimates of technical, economic and Achievable potential based on our Demand Side ASSYST model to better support the needs of the RI EERMC.

3.1.1 Review of other potential studies

In this task we reviewed eleven recent potential studies to develop initial estimates of technical, economic and achievable potential for electricity. Studies generally find that economic potential can range from 13 percent to 27 percent for electricity and 21-35 percent for gas. Achievable potential, which is the estimate of what can actually be achieved from programs, ranges from 10 percent to 33[6] percent for electric and 8-10 percent for gas.[7] Methodologies for Achievable potential can vary greatly. This analysis is discussed in Section 4 and provides an initial range for the estimates of potential. Phase II of the Opportunity Report will confirm or revise the findings regarding technical, economic and achievable potential based upon on-site and phone

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[6] The maximum achievable potential is higher than the maximum economic potential because one study did not report economic potential but provided a high estimate for achievable potential.
[7] Steve Nadel, Anna Shipley, and R. Neal Elliot, The Technical, Economic and Achievable Potential for Energy Efficiency in the US – A Meta-Analysis of Recent Studies, American Council for an Energy Efficient Economy, Proceedings from the 2004 ACEEE Summer Study on Energy Efficiency in Buildings.

survey research to be conducted in Rhode Island. The timing and focus of the Phase II work will be informed by results from Phase I through direction from the EERMC.

One primary task in Phase II is to conduct 300 completed phone surveys and 150 completed site visits. The site visits will likely be reserved for C&I sectors. The residential sector may need to be further broken down into the low income, non-low income, single-family and multi-family sectors subject to conversations with the EERMC.

3.1.2 Data collection and Interviews

Following from discussions at the project initiation meeting on April 30th, KEMA developed a list of all relevant data sources required for the project. This included:

- Data from any previous market characterization studies ;
- Data from recent utility programs;
- Data from recent best practices studies;
- Data from measure studies;
- Interviews with staff and market actors
- Load forecasting data;
- Impacts of new or pending federal or state legislation;
- Interviews with Rhode Island implementation vendors
- Review of recent process evaluations
- Review of other recent saturations surveys such as Vermont and Connecticut
- Review of recent new construction and retrofit projects
- Market research data ; and
- Studies for the state and other entities.

We did find that while there was much program data available for Rhode Island, there was very little data on:

- energy use by building type
- energy use by end use
- market penetrations and saturations of measures and end uses

This is discussed further in Section 6 and will be supplement with the onsite and phone survey data in Phase II.

3.2 Program Review

Our approach to program review was based on best practices. Best practices in energy efficiency program design have evolved over a period of 20 years, and continue to evolve as markets, regulatory agendas, and technologies change. For the most part, statements of best practice derive from the experience of organizations with long histories of efficiency/Demand-Side Management (DSM) program activity. These organizations have refined both their efficiency program designs and resource acquisition strategies and the processes through which such programs and acquisitions are developed and revised through long years of trial and error. Lessons learned from this experience are captured in a number of channels: conference papers and presentations, evaluation studies, and white papers by selected organizations to name a few.

3.2.1 Technical Data on Efficient Measure Opportunities

Estimating the potential for efficiency/DSM resources and options that are cheaper than supply requires a comparison of the costs and savings of efficiency/DSM measures relative to standard equipment and practices. Standard equipment and practices are often referred to in DSM analyses as base cases. Our team has collected measure cost data from a number of studies and sources, including data from California's Database for Energy-Efficient Resources (DEER, for which Itron is the prime contractor) and the Northwest Power Planning Council's RTF database/website, among others. Additional measure cost information has been obtained from the utility filings, as well as other secondary sources and interviews with utility program managers and other industry experts. Most of our savings data for Phase I comes from utility data, appropriate regional evaluation studies, and the recent DEER study, with appropriate adjustments for baseline conditions in Rhode Island. We have supplemented using other data for measures where data may not be available.

Estimates of DSM measure savings as a percentage of base equipment usage were developed from a variety of sources, including:

- Current program data;
- Analysis of actual measured savings from ex-post evaluation studies of energy efficiency programs;
- Other recent New England studies such as Vermont and the Nstar/ Cape Light study
- Industry-standard engineering calculations; and

- Estimated savings from the DEER databases; and
- Secondary sources, including our team's recent DSM potential studies as well as that of the Energy Trust of Oregon and Northwest Energy Efficiency Alliance.

3.2.2 Initial Energy Efficiency Measure Screening

In this task we developed an initial energy efficiency measure list and provide an initial screening of measures to undergo further analysis. To implement the initial measure screening, we developed initial runs of our DSM ASSYST model.

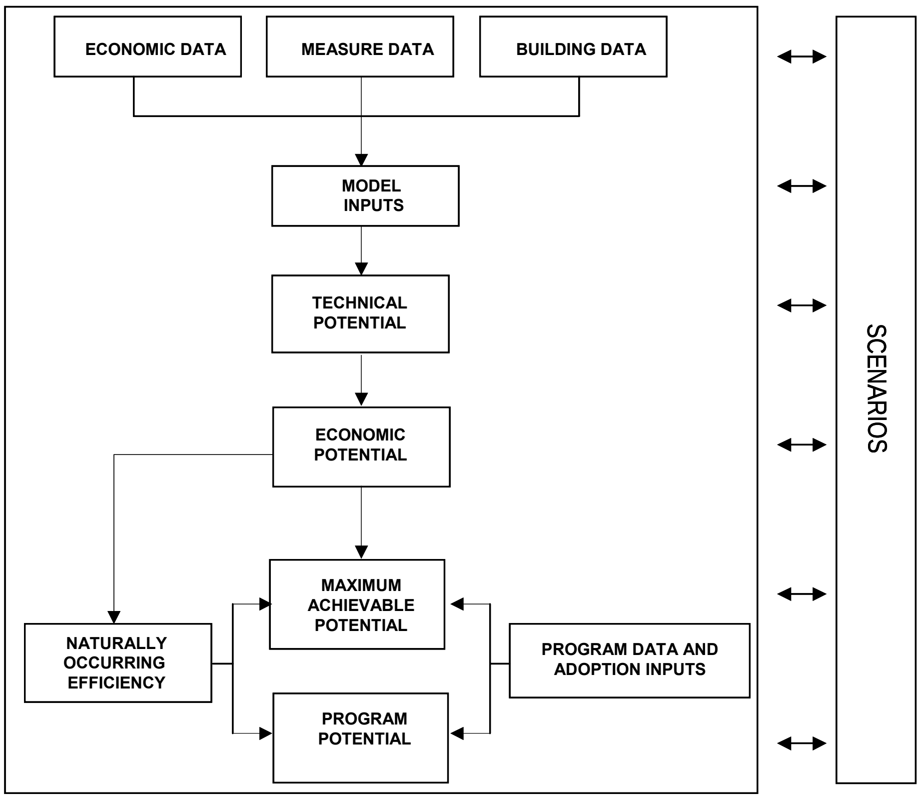
3.2.3 Initial Runs of Demand Side Assyst

We used the data available to develop initial estimates of potential using Demand Side ASSYS prior to the data collection that will be done in Phase II of this project. Our method for estimating potential for energy efficiency in is a "bottom-up" approach, utilizing DSM ASSYST™, our MS-Excel®-based forecasting model. The basic analytical steps are shown in Figure 3-1. In this approach, we assess costs and savings at the market segment and energy efficiency measure level. This method requires data regarding targeted measures and market segments, including the following elements to determine how much efficiency resource is available that is less expensive than supply:

- Energy efficiency measure costs
- Energy efficiency measure savings
- Base energy consumption by market segment and end use
- Applicability of a measure to a given market segment and end use
- The current saturation of the measure in the market segment
- The fraction of the market segment that can feasibly utilize the measure
- The number of consuming units (i.e., square feet or number of homes) within a market segment
- End-use load shapes
- Avoided-cost forecasts
- Rate forecasts
- Program funding levels by category (marketing, incentives, and administration).

Limited Rhode Island data were available to complete this analysis at this time. We had complete measure data, but very limited building data. This effort will be supplemented by the Phase II onsite and phone survey work.

Figure 3-1
Simplified Conceptual Overview of Modeling Process



In our bottom-up approach, we first estimate **technical potential** for energy savings by integrating key measure and market segment parameters using the following equation:

$$\text{Technical Potential of Efficient Measure} = \text{Total sq. ft. or \# of Dwellings} \times \text{Base Case Equipment EUI or UEC} \times \text{Applicability Factor} \times \text{Not Complete Factor} \times \text{Feasibility Factor} \times \text{Savings Factor}$$

We then assess **economic potential** by first developing a supply-curve analysis. This analysis eliminates double counting of measure savings. On a market segment and end-use/technology basis, measures are stacked in order of cost effectiveness, and the energy consumption of the system being affected by the efficiency measures goes down as each measure is applied. As a result, the savings attributable to each subsequent measure decrease if the measures are interactive. After eliminating double counting of savings, the benefits and costs associated with a given measure and market segment are compared using the Total Resource Cost (TRC), which is the test specified by the Least Cost Procurement and System Reliability Standards.

4. Review of Other Potential Studies

For this study we reviewed twelve other potential studies. They are listed below as well as their percentage estimates of technical and economic potential. These results present a similar pattern – The residential and commercial sectors typically have a technical potential of around 30 percent.

Review of Selected Technical Potential Studies

		Residential %		Commercial %		Industrial %		Length of
Source	**State**	**Technical**	**Economic**	**Technical**	**Economic**	**Technical**	**Economic**	**Study - years**
KEMA	New Jersey	25.8%	18.9%	24.4%	18.7%	9.8%	7.9%	2004 - 2020
KEMA	Ireland	43.0%	36.0%	29.0%	29.0%	12.0%	11.0%	2007 - 2020
ITRON/KEMA	California	30.0%	23.0%	15.0%	12.0%	17.0%	15.0%	2004 - 2016
ICF	Georgia	33.0%	21.0%	33.0%	22.0%	17.0%	15.0%	2005 - 2015
ICF	Ontario	24.6%	20.5%	31.4%	23.5%	20.1%	17.9%	2004 - 2015
GDS Associates	Vermont	39.8%	20.6%	31.9%	16.5%	20.7%	14.5%	2007 - 2015
GDS Associates	North Carolina	39.7%	17.8%	32.2%	12.1%	21.5%	10.8%	2008 - 2017
SWEEP	Arizona	29.9%		37.2%	37.2%	33.3%		2003 - 2020
SWEEP	Colorado	22.1%		37.0%		28.8%		2003 - 2020
KEMA	California	27.9%	21.4%	18.0%	13.0%			2003 - 2012
Excel Energy	Colorado	20.0%	15.0%	22.0%	17.0%	14.0%	13.0%	2006 - 2013
Average		30.5%	21.6%	31.4%	20.1%	19.4%	13.1%	
Median		30.0%	21.4%	31.4%	18.7%	20.1%	15.0%	

Industrial is typically lowest with an average around 20% for technical potential. Economic potential is typically 8-10 percentage points less than technical potential. Jurisdictions that have been more active have lower potential than studies in places such as North Carolina and Ireland where there has been little programmatic activity. We attempted to compare achievable potential to economic potential on a consistent basis from these studies but found that it was either not calculated or was done in a consistent manner across studies. We were able to calculate a relationship between technical potential and economic potential which is show below:

Sector	Relationship between achievable potential and technical potential
Residential	68.8 %
Commercial	67.8 %
Industrial	76.3 %

This is based on a sub set of four to five of the studies.

5. Review of Rhode Island Programs and Possible New Program and Measure Areas

This section presents the findings of the review of Rhode Island programs compared to Best Practice and Other Portfolios. Additionally, based on this review we identified possible new program areas and emerging technologies.

5.1 Best Practices Review

We reviewed Rhode Island's programs relative to two major best practices studies:

www.eebestpractices.com[8] and

EPA's National Energy Action Plan[9]

The best practices study conducted by Quantum (now Itron) was sponsored by the California Utilities. This review covered both over arching best practices and best practices relative to individual program sectors for energy efficiency program design. We used this study to compare Rhode Island's programs at an individual program area. Many of the programs offered by National Grid in Rhode Island were listed in this study as best practice as show in Table 5-1 below:

[8] Study sponsored by PG&E and other California utilities, authored by Quantum Consulting, (now Itron) – can be found at: www.eebestpractices.com

[9] http://www.epa.gov/cleanenergy/energy-programs/napee/resources/action-plan.html

Table 5-1
Programs offered by National Grid

Program Area	National Grid programs included:	Samples of other programs included
Residential Lighting	Massachusetts Energy Star Lighting Program	Energy Star Lighting - UI
Residential AC		Residential AC program – FP&L
Residential Single Family - Comprehensive	Energy Wise	Residential High Use - NSTAR
Residential Multi Family – Comprehensive	Energy Wise	
Residential- informational	Massachusetts Electric RCS Audit	E+ Audit for Your Home – Northwestern Energy
Residential New Construction		Vt Energy Star New Homes CA Energy Star New Homes
C/I - Lighting		Small Business Energy Express – CA Small Business Energy Advantage- NU
C/I - HVAC		Chiller Efficiency Program
Large Comprehensive	Comprehensive Chiller Program Energy Initiative	Power Smart Partners – BC Hydro
New Construction	Design 2000	Design 2000

Overarching Best Practices

We used both www.eebestpractices and the EPA national energy plan to distill overarching best practices.[10]

At the energy efficiency program level, some of the key lessons learned are as follows.

[10] For example, the website www.eebestpractices.com, which contains the results of best practices research commissioned by Pacific Gas & Electric and *The National Action Plan for Energy Efficiency,* Chapter 6.

- Efficiency programs and resource acquisition should harness the motivations and knowledge of market participants, not compete with firms and individuals on the supply side of markets (trade allies) for energy-related products and services.
- Efficiency programs and resource acquisition should be designed specifically to address barriers to the acceptance of energy-efficient goods and services, as identified through market studies in the jurisdiction or elsewhere.
- Promote non-energy benefits of energy-efficient designs and products, such as increased occupant comfort or control over production machinery. These often have greater value to decision-makers than energy savings.
- Keep participation for customers and vendors simple.
- Target incentives to the key decision makers in the value chain. For example, incentives in residential new construction programs are best targeted to builders, who effectively make most decisions in regard to energy-related home features.
- Leverage existing brands such as utility brands and the Energy Star Brand
- Understand local market conditions
- Use evaluation to improve efficiency programs and resource acquisition over time
- Perform appropriate market research to understand markets and baselines
- Use electronic means as much as possible for program efficiency
- Use existing channels

At the portfolio level, key lessons learned include the following:

- Have efficiency programs and resource acquisition for all sectors
- Focus efficiency program efforts and resource acquisition on market segments and technologies in which there are large untapped potential savings.
- Maintain flexibility to add, drop, or revise efficiency measure eligibility and rebates in response to feedback from the field and formal evaluations.
- Tie employees incentives to overall portfolio goals
- Have stable, predictable budgets

Our review of National Grid's programs indicates the programs offered in Rhode Island generally meet many of these practices. Areas where there could be improvement include:

- Performing more regular evaluations of the RI efficiency programs
- Obtaining baseline data such as market saturations and penetrations for efficiency
- Combining electric and gas program infrastructure for efficiency
- Additional comprehensiveness of efficiency resource acquisition in large Commercial / Industrial programs

5.2 Comparison to Other Portfolios

We compare the Rhode Island programs on a cost basis to portfolios presented in the EPA's National Action Plan[11] for Energy Efficiency as the data is presented in a consistent manner. The results of the 2006 RI programs are presented below:

Year: 2006	Sector	Approved Budget	Year End	Actual MW	Lifetime mwh	Lifetime MW	Lifetime MWH	$/ lifetime MWH
Energy*Wise*	Residential	$1,888.4	$2,018.6	0.345	3,408	3.633	39,027.0	0.052
Single Family Low Income Services	Residential	$1,684.4	$1,922.5	0.128	1,227	1.859	16,854.0	0.114
ENERGY STAR Appliances	Residential	$345.3	$319.5	0.358	1,468	4.696	20,405.0	0.016
ENERGY STAR Heating Program	Residential	$109.8	$101.0	0.000	10	0.001	117.0	0.863
ENERGY STAR Central A/C Program	Residential	$174.9	$118.7	0.028	17	0.479	285.0	0.416
ENERGY STAR Lighting	Residential	$780.6	$760.4	1.022	16,076	6.490	101,235.0	0.008
ENERGY STAR Homes	Residential	$988.0	$1,112.3	0.235	1,323	4.600	13,487.0	0.082
Energy Efficiency Education Programs	Residential	$48.6	$55.9	n/a	n/a	n/a	n/a	n/a
	SUBTOTAL	$6,020.0	$6,408.9	2.116	23,529	21.758	191,410.0	0.033
Design 2000*plus*	Large Commer	$2,729.0	$2,339.5	1.696	8,326	28.079	136,946.0	0.017
Energy Initiative	Large Commer	$3,842.5	$4,615.9	4.731	29,498	59.332	371,494.0	0.012
	SUBTOTAL	$6,571.5	$6,955.4	6.427	37,824	45.079	508,440.0	0.014
Small Business Services	Small Commer	$3,592.1	$4,061.8	2.160	9,297	26.115	112,961.0	0.036
	SUBTOTAL	$3,592.1	$4,061.8	2.160	9,297	26.115	112,961.0	0.036
	Overall		$17,426.1				812,811.0	0.021

Source:
National Grid 2006 Year-End Report

The costs/lifetime MWH in the EPA best Practices report ranged from $.01/ lifetime MWH to $.05 per lifetime MWH. The Rhode Island portfolio falls comfortably in this range at: $.021/ lifetime MWH. As in most of the other portfolios, large C/I is typically the lowest cost/ lifetime MWH.

[11] http://www.epa.gov/cleanenergy/energy-programs/napee/resources/action-plan.html

The utilities, public administrator and states used in this comparison are presented below:

Utilities used in EPA Portfolio Comparison

Nevada	Connecticut
SMUD	Seattle City Light
Austin Energy	BPA
Minnesota	NYSERDA
Efficiency Vermont	Massachusetts
Wisconsin Department of Administration	California IOUs

All of these portfolios like Rhode Island have comprehensive programs for all customer classes. A program review was conducted as part of this effort. Program areas/ efficiency measures that are not offered by Rhode Island included:

- Appliance Recycling (Ca utilities)
- Rebates for more efficient computer equipment (Ca utilities)
- Ties to LEED in new construction programs (Austin, Nevada))
- Water heater rebates (Ca utilities)
- Load control of AC for small C/I and residential (many including Austin Energy and Ca Utilities)
- Retrocommissioning (Nevada)
- Solar hot water heat (Ca utilities)
- Data center rebates (Ca utilities)
- Cool roofs programs or measures (Ca and Nevada)
- Performance based Commercial Lighting (suggested from the RI interviews)

5.3 Identification of New Program Areas and Measures

Our review of other portfolios as indicated in the previous section indicated the following potential new energy efficiency program areas and resource acquisition strategies for Rhode Island:

- Adding an appliance recycling program (residential)
- Adding a retro commissioning program (commercial/ industrial)
- Direct ties to LEED in new construction programs
- Adding a data center program
- Adding a direct load control program

We have included an appliance recycling component in the technical and economic potential described in section 7 and the direct load control program in the load response section. We plan to model both a data center program, more direct ties to LEED and retro commissioning as part of the Phase II study as the data is more speculative.

We also identified new potential measures that may be applicable in 2-5 years. This list was developed from a review of emerging technologies from ACEEE, LBL and other utilities. We list them here for consideration and plan to model them in Phase II.

Potential New Residential Energy Efficiency Measures

- LED's
- Cool roofs
- Commissioning
- Energy recovery ventilation
- Smart AC
- EnergyStar or Better PC
- EnergyStar or Better TV
- EnergyStar or Better Set-Top
- Heat pump dryer

- Solar hot water heating
- AC control

Potential new Commercial / Industrial Efficiency Measures

- LED's (residential and C/I)
- Cool roofs
- Commissioning
- Energy recovery ventilation
- Smart AC
- LED Downlights
- Induction Lighting
- CDMi replacement for incandescent or halogen reflector lamps
- Data center package
- AC control

6. Draft Tech and Economic Potential from DSM ASSYST

6.1 Breakdown of Potential and Benefits

In this section we provide additional information on the estimates of electric efficiency potential developed for this study. We discuss results by customer class, end use, and type of measure.

6.1.1 Electric Technical and Economic Potential

All Sectors. The technical and economic potential for energy savings in the Rhode Island energy service territory are shown in Figure 6-1 and Table 6-1. Overall technical potential for energy savings in the residential, commercial, and industrial sectors is approximately 688 MW and the potential for economic energy savings is estimated to be approximately 518 MW. That is, more than 500 MW of energy efficiency that is cheaper than supply have been estimated to exist as an untapped resource in Rhode Island. The residential sector contributes the most to both technical and economic savings potential, followed by the commercial sector.

Figure 6-1 presents a summary of the technical potential and economic potential (efficiency resources that are cheaper than supply) in MW for Rhode Island.

Figure 6-1
Technical and Economic Demand Savings Potential
by Market Sector in Rhode Island – MW

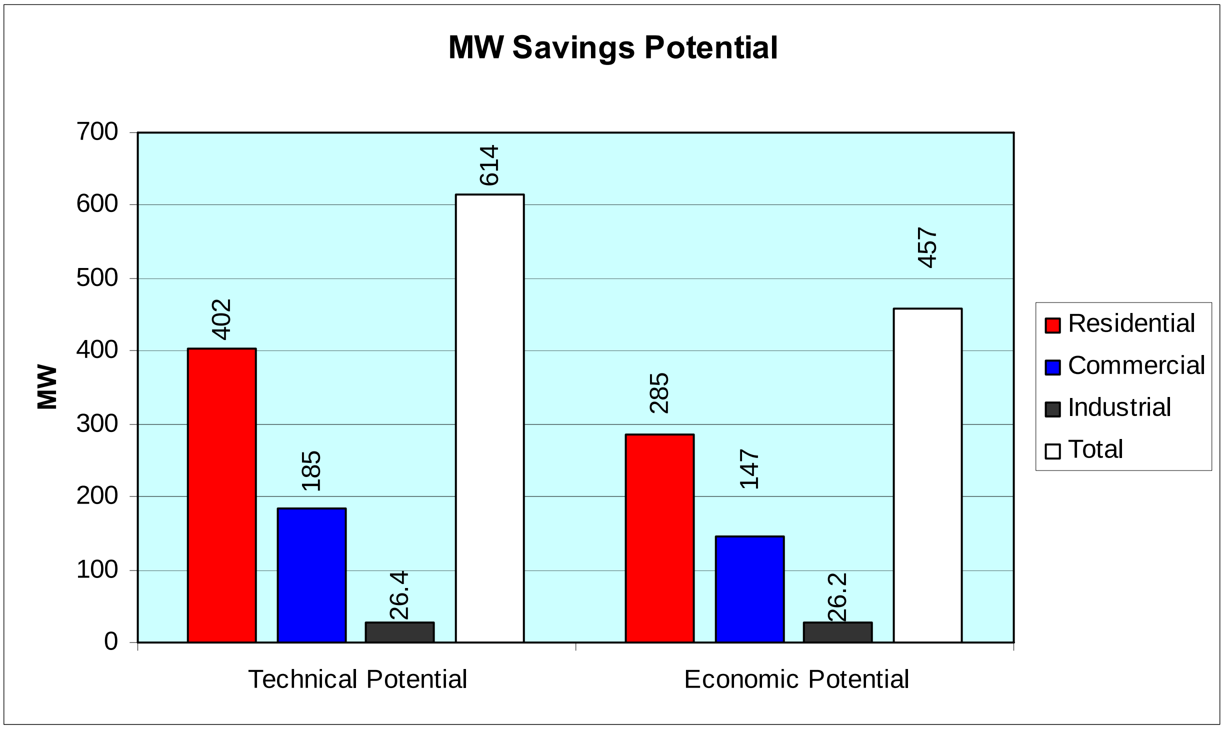


Figure 6-2 presents a summary of the technical potential and economic potential (efficiency resources that are cheaper than supply) in GWh savings for Rhode Island. This chart shows a similar pattern to the MW chart as far as savings from each sector.

Figure 6-2
Technical and Economic Demand Savings Potential
by Market Sector in Rhode Island –GWH

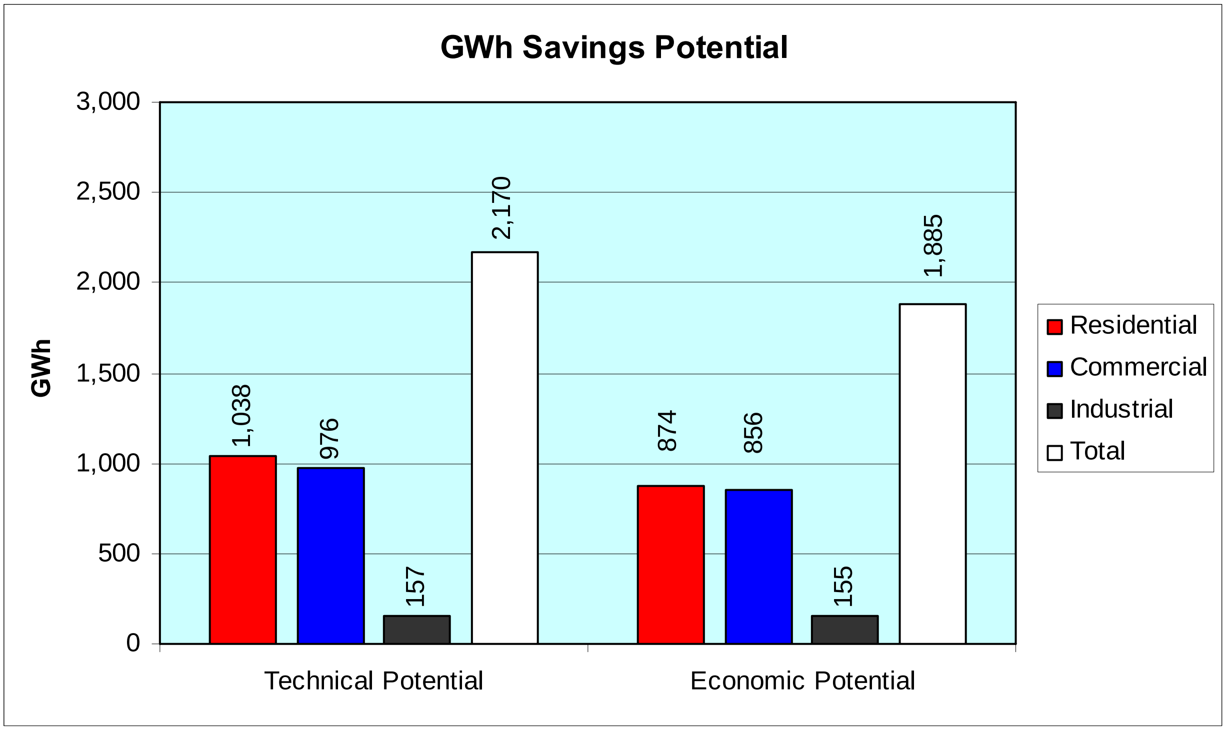


Table 6-1
Technical and Economic Demand Savings Potential
by Market Sector in Rhode Island – MW
2017 Electric Demand Savings

MW	Technical Potential	Economic Potential
Residential	402.3	284.7
Commercial	185	146.6
Industrial	26.4	26.2
Overall	613.5	457.5

Annual GWh savings are presented in Figure 6-3 for Rhode Island. Figure 6-4 presents GWh technical potential efficiency savings as percent of total energy for that Sector.

Figure 6-3
Technical Electric Energy Savings Potential by Market Sector in Rhode Island in 2017 in GWh/Year

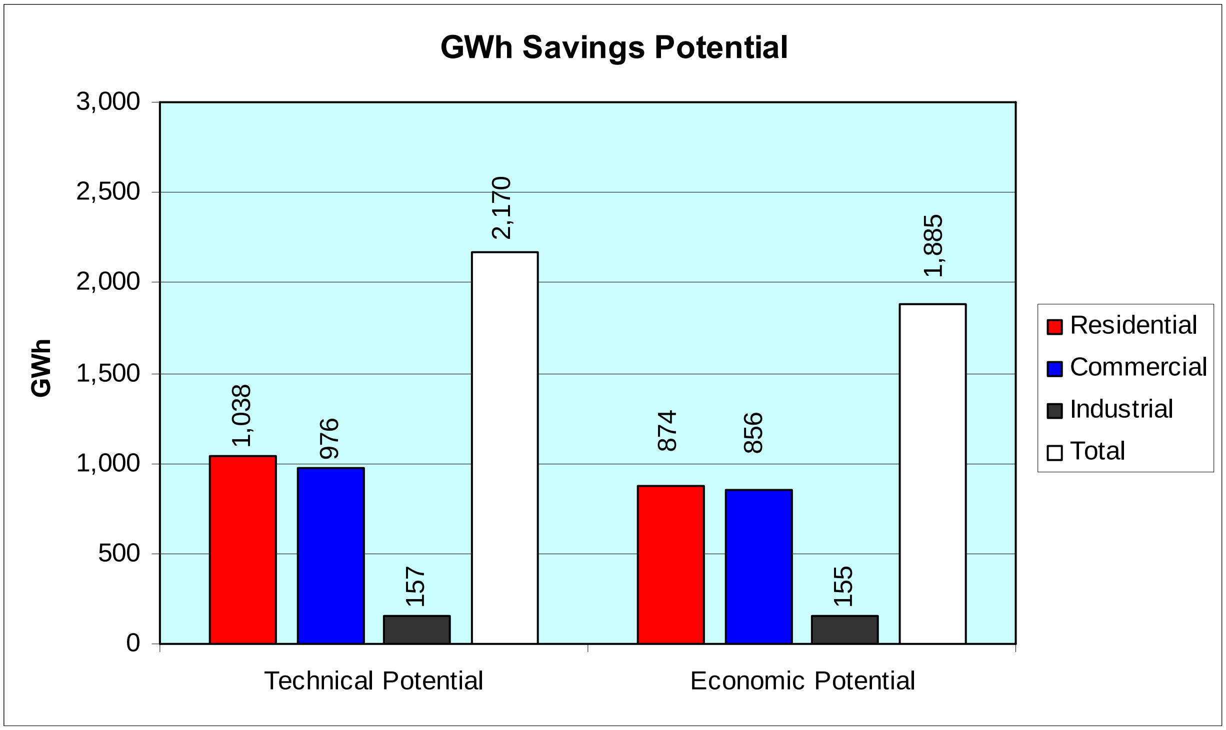


Figure 6-4

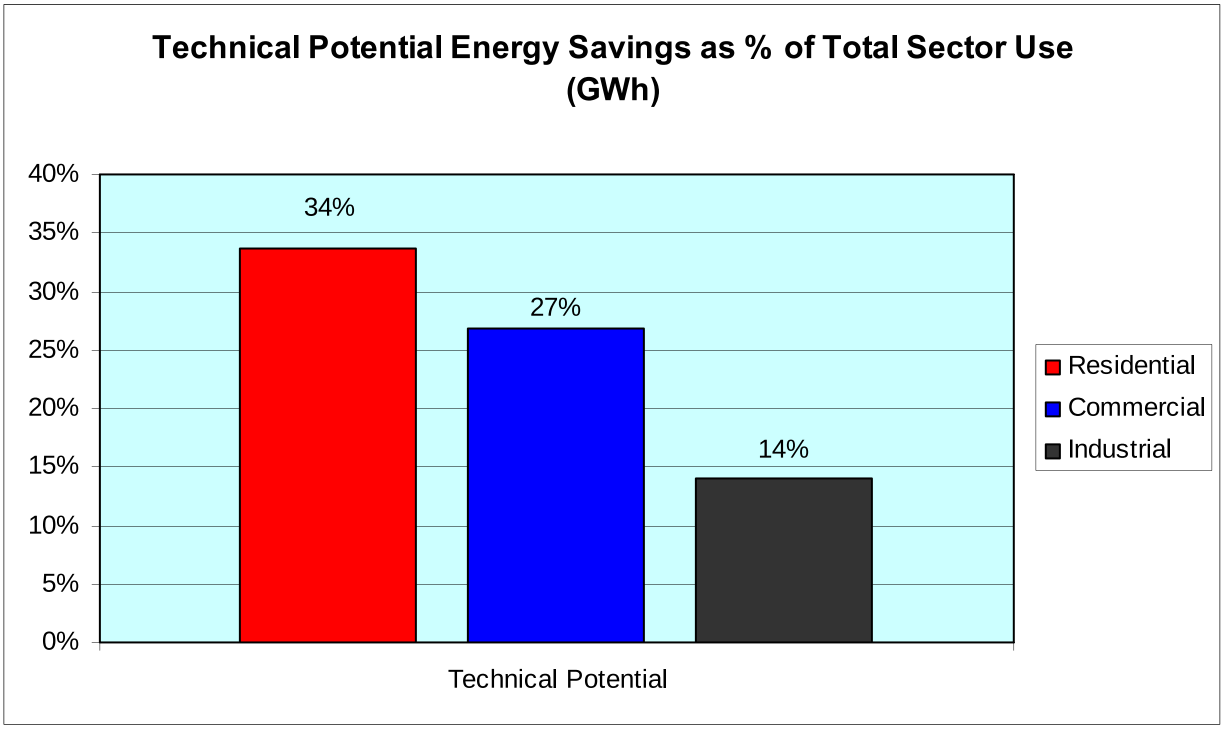


Table 6-2
Technical and Economic Electric Energy Savings Potential by Market Sector in Rhode Island

GWh/Year	Technical Potential	Economic Potential
Residential	1,038	874
Commercial	976	856
Industrial	157	155
Overall	2,170	1,885

Residential Sector. Residential economic potential in Rhode Island is presented by key end use in Figure 6-5. Key contributors to overall economic potential for energy are from appliances, HVAC and lighting. Most of the demand savings come from HVAC as shown in Figure 6-6.

Figure 6-5
Residential Energy Use Economic Potential by End Use (GWh)

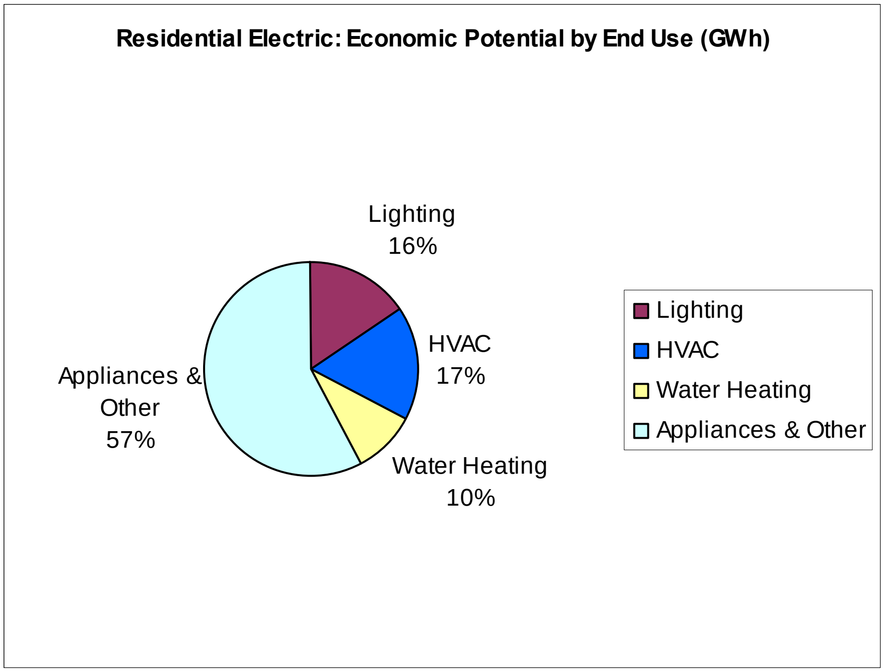
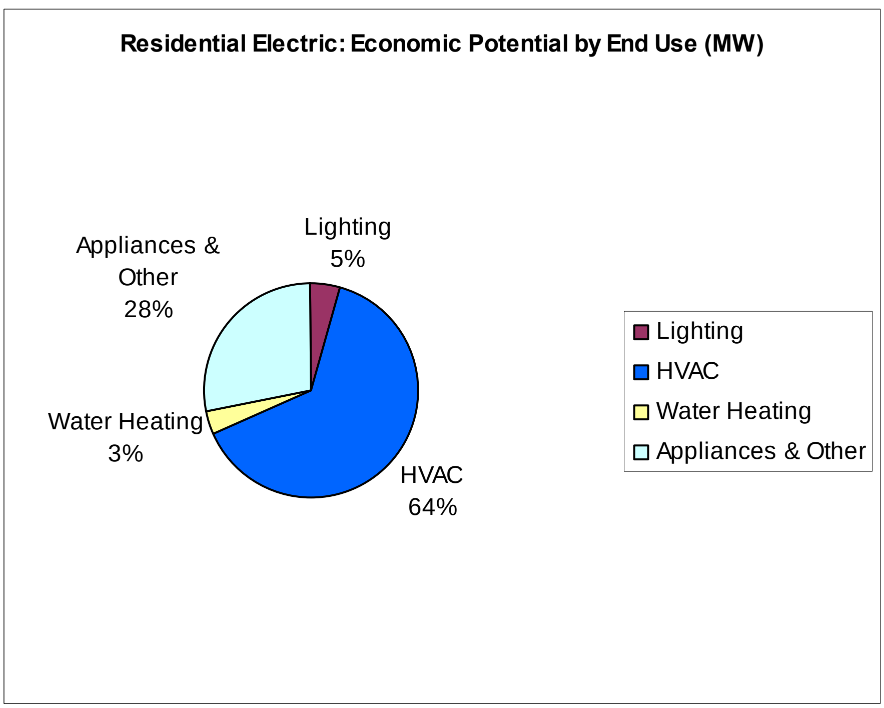


Figure 6-6
Residential Demand Economic Potential by End Use (MW)



Commercial Sector. Total economic potential for the commercial sector is approximately 1,026 GWh. Figure 6-7 and Figure 6-8 show commercial sector economic potential estimates by key end use. Lighting dominates both the energy savings (73 percent of total) and demand savings (66 percent). End uses in the "other" category include refrigeration, water heating, and office equipment.

Figure 6-7
Commercial Energy Use Economic Potential by End Use (GWh)

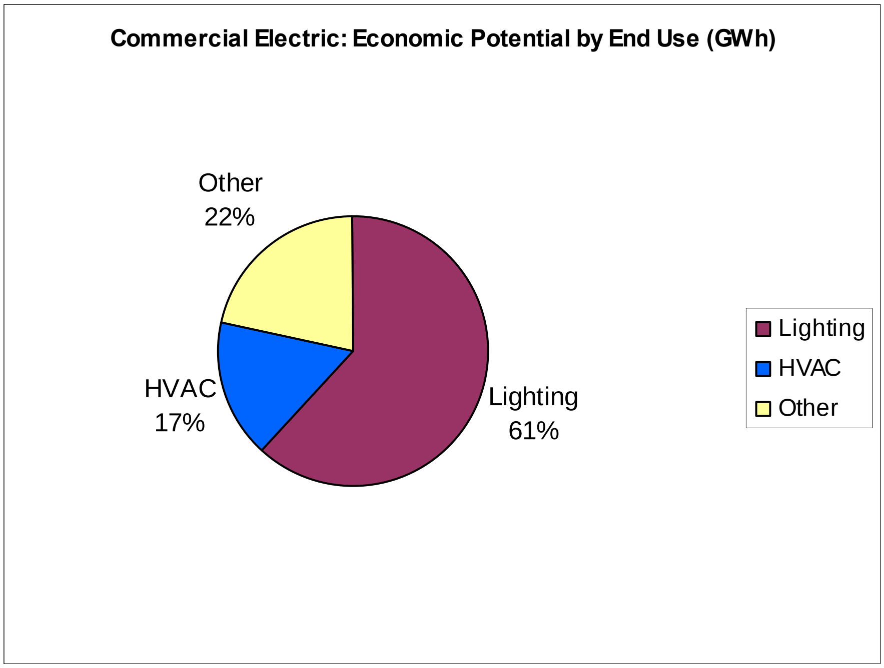
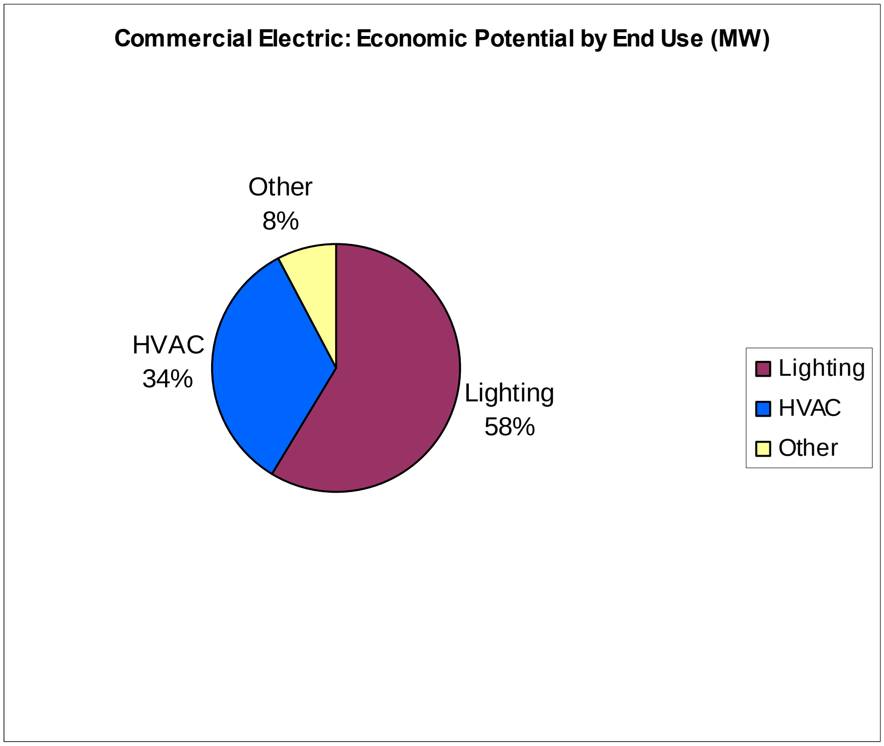


Figure 6-8
Commercial Demand Economic Potential by End Use (MW)



Industrial Sector. Total industrial sector economic potential estimates by key end use. The technical potential is dominated by process improvements. Figure 6-9 presents the breakdown by endues for energy. Figure 6-10 presents similar data for demand.

Figure 6-9
Industrial Energy Use Economic Potential by End Use (GWh)

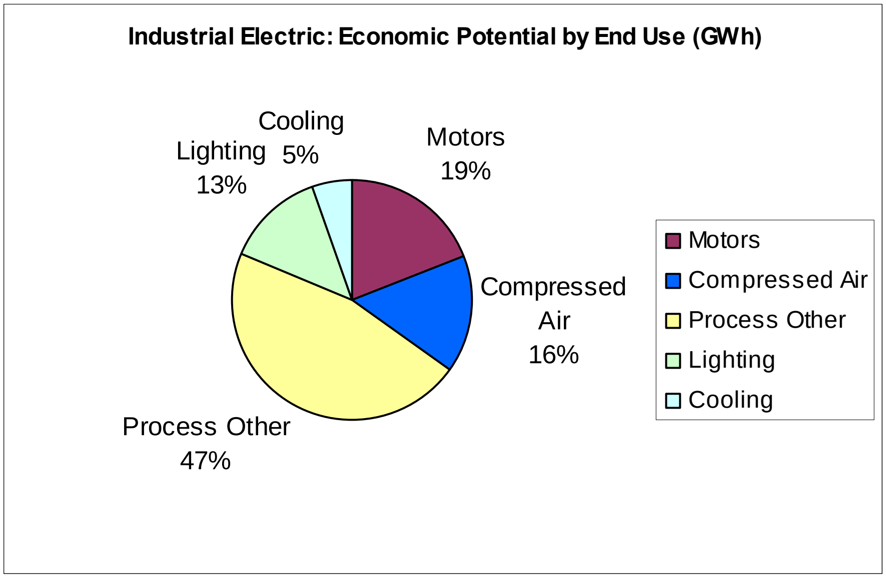
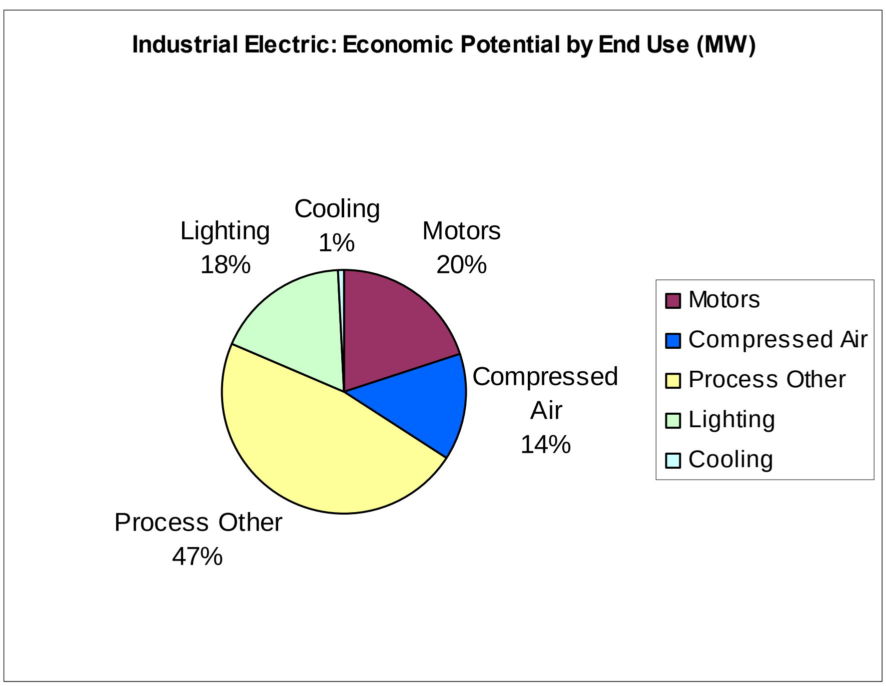


Figure 6-10
Industrial Demand Economic Potential by End Use (MW)



6.2 Achievable Potential and Net Benefits

We developed two cases of achievable potential – Base and aggressive. A summary of the two cases is provided below in Table 6-3 and Table 6-4. The base case is similar to the existing funding level and the aggressive case has a significantly higher funding level. We developed the Aggressive case by significantly increasing the marketing budgets for some program areas as well as increasing the incentives. We used a simpler approach to this process than will be conducted in phase II. We developed overall achievable cases at the sector level not the program level except for new construction. We did develop estimates for some new programs outside the model - namely for a mass market (residential and small commercial load control) and appliance recycling. These are presented in Section 9.

KEMA

Table 6-3
Summary of the Base Case

Residential	Base Case				
	Year	2009	2010	2011	2018
	Administration	$748,700	$774,910	$785,497	$753,567
	Marketing	$141,700	$143,230	$144,776	$156,076
	Incentives	$4,383,156	$4,576,990	$4,647,010	$4,290,619
	Total	$5,273,556	$5,495,130	$5,577,283	$5,200,263
	Net Energy Savings - GWh	16	33	49	129
	Net Peak Electricity Demand Savings - kW	4,219	8,528	12,811	38,676
	Annual Participant Costs (Real)	$7,061,100	$6,892,775	$6,601,562	$4,024,193
	Annual PV Participant Costs	$7,061,100.13	$6,823,137.44	$6,468,845.15	$3,672,729.43
	Naturally Occurring Energy Savings Total (Annual)	12	11	10	6
	Naturally Occurring Peak Demand Savings Total (Annual)	1,782	1,632	1,499	874
	PV Avoided Costs	$35,193,568	$34,639,985	$32,351,318	$15,355,514
	PV Program Costs	$5,273,556	$5,439,613	$5,465,158	$4,746,084
	Annual TRC	2.85	2.82	2.71	1.82
Commercial Base Case					
	Year	2009	2010	2011	2018
	Administration	$1,602,280	$1,528,377	$1,532,945	$1,440,954
	Marketing	$64,430	$65,126	$65,829	$70,967
	Incentives	$7,569,027	$7,802,972	$7,850,238	$5,057,460
	Total	$9,235,737	$9,396,475	$9,449,011	$6,569,381
	Net Energy Savings - GWh	28	57	87	229
	Net Peak Electricity Demand Savings - kW	4,074	8,457	12,949	36,833
	Annual Participant Costs (Real)	$13,821,619	$14,020,780	$13,876,448	$8,578,410
	Annual PV Participant Costs	$13,821,619.02	$13,879,128.00	$13,597,477.35	$7,829,192.83
	Naturally Occurring Energy Savings Total (Annual)	31	30	30	20
	Naturally Occurring Peak Demand Savings Total (Annual)	3,492	3,523	3,521	2,646
	PV Avoided Costs	$50,420,905	$51,797,809	$49,738,270	$16,970,826
	PV Program Costs	$9,235,737	$9,301,542	$9,259,050	$5,995,627
	Annual TRC	2.19	2.23	2.18	1.23
Industrial Base Case					
	Year	2009	2010	2011	2018
	Administration	$451,920	$441,967	$409,487	$135,110
	Marketing	$18,000	$18,194	$18,391	$19,826
	Incentives	$2,559,620	$2,503,248	$2,319,282	$765,246
	Total	$3,029,540	$2,963,409	$2,747,159	$920,182
	Net Energy Savings - GWh	20	39	56	120
	Net Peak Electricity Demand Savings - kW	4,290	8,351	11,996	25,965
	Annual Participant Costs (Real)	$3,081,765	$3,017,751	$2,840,478	$1,162,571
	Annual PV Participant Costs	$3,081,765	$2,987,263	$2,783,373	$1,061,035
	Naturally Occurring Energy Savings Total (Annual)	3	3	3	3
	Naturally Occurring Peak Demand Savings Total (Annual)	642	657	663	528
	PV Avoided Costs	$42,413,566	$38,993,160	$33,132,229	$6,847,109
	PV Program Costs	$3,029,540	$2,933,470	$2,691,931	$839,816
	Annual TRC	6.94	6.59	6.05	3.60
Total Base Case					
	Year - Program Costs-Real	2009	2010	2011	2018
	Administration	$2,802,900	$2,745,254	$2,727,928	$2,329,631
	Marketing	$224,130	$226,549	$228,995	$246,869
	Incentives	$14,511,803	$14,883,210	$14,816,530	$10,113,325
	Total	$17,538,833	$17,855,014	$17,773,453	$12,689,825
	Net Energy Savings - GWh	64	129	192	478
	Net Peak Electricity Demand Savings - kW	12,584	25,335	37,756	101,474
	Annual Participant Costs (Real)	$23,964,484	$23,931,306	$23,318,488	$13,765,174
	Annual PV Participant Costs	$23,964,484	$23,689,528	$22,849,696	$12,562,957
	Naturally Occurring Energy Savings Total (Annual)	46	45	44	29
	Accumulated Naturally Occurring Energy Savings Total (Annual)	46	91	135	381
	Naturally Occurring Peak Demand Savings Total (Annual)	5916	5812	5683	4048
	Accumulated Naturally Occurring Peak Demand Savings Total (Annua	5916	11728	17411	51061
	PV Avoided Costs	$128,028,039	$125,430,954	$115,221,818	$39,173,449
	PV Program Costs	$17,538,833	$17,674,625	$17,416,138	$11,581,527
	Annual TRC	3.08	3.03	2.86	1.62
	Program Lifetime cents/kwh for that year	0.022	0.022	0.023	0.044
	Additional Programs- Budget				
	Appliance Recycling	1053000	1053000	1053000	1053000
	Direct Load Control	$650,000	$1,040,000	$1,210,564	$871,643
	Total National Grid Budget	$19,241,833	$19,948,014	$20,037,017	$14,614,468
	Additional ISO				

Both Tables present the same pattern – spending drops off later in the period as most of the lighting in all sectors has been converted to more efficient stock.

Table 6-4
Summary of the Aggressive Case

Aggressive Case

Residential Aggressive Case				
Year	2009	2010	2011	2018
Administration	$748,700	$811,596	$836,513	$908,902
Marketing	$141,700	$212,659	$280,923	$1,048,212
Incentives	$14,725,008	$15,948,308	$16,472,190	$17,852,723
Total	$15,615,408	$16,972,564	$17,589,627	$19,809,837
Net Energy Savings - GWh	32	65	97	273
Net Peak Electricity Demand Savings - kW	12,512	25,304	38,022	122,500
Annual Participant Costs (Real)	$10,566,984	$10,626,998	$10,366,996	$8,150,119
Annual PV Participant Costs	$10,566,984	$10,519,633	$10,158,580	$7,438,308
Naturally Occurring Energy Savings Total (Annual)	12	11	10	6
Naturally Occurring Peak Demand Savings Total (Annual)	1,782	1,632	1,499	874
PV Avoided Costs	$79,415,834	$79,044,847	$74,139,884	$39,041,939
PV Program Costs	$15,615,408	$16,801,090	$17,236,007	$18,079,695
Annual TRC	3.03	2.89	2.71	1.53

Commercial Aggressive				
Year	2009	2010	2011	2018
Administration	$1,602,280	$1,650,004	$1,797,300	$2,339,510
Marketing	$64,430	$138,057	$255,865	$505,573
Incentives	$18,730,390	$19,843,162	$20,541,022	$12,300,018
Total	$20,397,100	$21,631,223	$22,594,186	$15,145,101
Net Energy Savings - GWh	44	93	144	371
Net Peak Electricity Demand Savings - kW	7,333	15,434	24,070	67,927
Annual Participant Costs (Real)	$21,798,101	$22,373,794	$22,577,637	$13,223,600
Annual PV Participant Costs	$16,648,068	$16,648,069	$16,648,070	$16,648,071
Naturally Occurring Energy Savings Total (Annual)	31	30	30	20
Naturally Occurring Peak Demand Savings Total (Annual)	3,492	3,523	3,521	2,646
PV Avoided Costs	$82,392,411	$87,303,677	$87,383,738	$23,092,158
PV Program Costs	$20,397,100	$21,412,684	$22,139,955	$13,822,365
Annual TRC	1.95	2.00	1.97	0.89

Industrial Aggressive				
Year	2009	2010	2011	2018
Administration	$451,920	$441,967	$409,487	$135,110
Marketing	$18,000	$18,194	$18,391	$19,826
Incentives	$2,559,620	$2,503,248	$2,319,282	$765,246
Total	$3,029,540	$2,963,409	$2,747,159	$920,182
Net Energy Savings - GWh	20	39	56	120
Net Peak Electricity Demand Savings - kW	4,290	8,351	11,996	25,965
Annual Participant Costs (Real)	$3,081,765	$3,017,751	$2,840,478	$1,162,571
Annual PV Participant Costs	$3,081,764.61	$2,987,263.04	$2,783,373.50	$1,061,034.67
Naturally Occurring Energy Savings Total (Annual)	3	3	3	3
Naturally Occurring Peak Demand Savings Total (Annual)	642	657	663	528
PV Avoided Costs	$42,413,566	$38,993,160	$33,132,229	$6,847,109
PV Program Costs	$3,081,765	$2,987,263	$2,783,373	$1,061,035
Annual TRC	6.88	6.53	5.95	3.23

Total Aggressive Case				
Year	2009	2010	2011	2018
Administration	$2,802,900	$2,903,567	$3,043,299	$3,383,523
Marketing	$224,130	$350,716	$536,788	$1,553,784
Incentives	$36,484,938	$35,791,471	$37,013,212	$30,152,741
Total	$39,511,968	$39,045,754	$40,593,299	$35,090,048
Net Energy Savings - GWh	96	197	296	764
Net Peak Electricity Demand Savings - kW	24,136	49,089	74,088	216,392
Annual Participant Costs (Real)	$3,081,765	$3,017,751	$2,840,478	$1,162,571
Annual PV Participant Costs	$3,081,765	$2,987,263	$2,783,373	$1,061,035
Naturally Occurring Energy Savings Total (Annual)	3	3	3	3
Accumulated Naturally Occurring Energy Savings Total (Annual)	46	91	135	381
Naturally Occurring Peak Demand Savings Total (Annual)	5,916	5,812	5,683	4,048
Accumulated Naturally Occurring Peak Demand Savings Total (Annual)	5,916	11,728	17,411	51,061
PV Avoided Costs	$204,221,811	$208,762,089	$203,937,187	$104,547,662
PV Program Costs	$39,094,273	$41,201,037	$42,159,336	$32,963,094
Annual TRC	2.74	2.70	2.62	1.88
Program costs/ lifetime kwh for program year	$0.03	$0.03	$0.03	$0.08

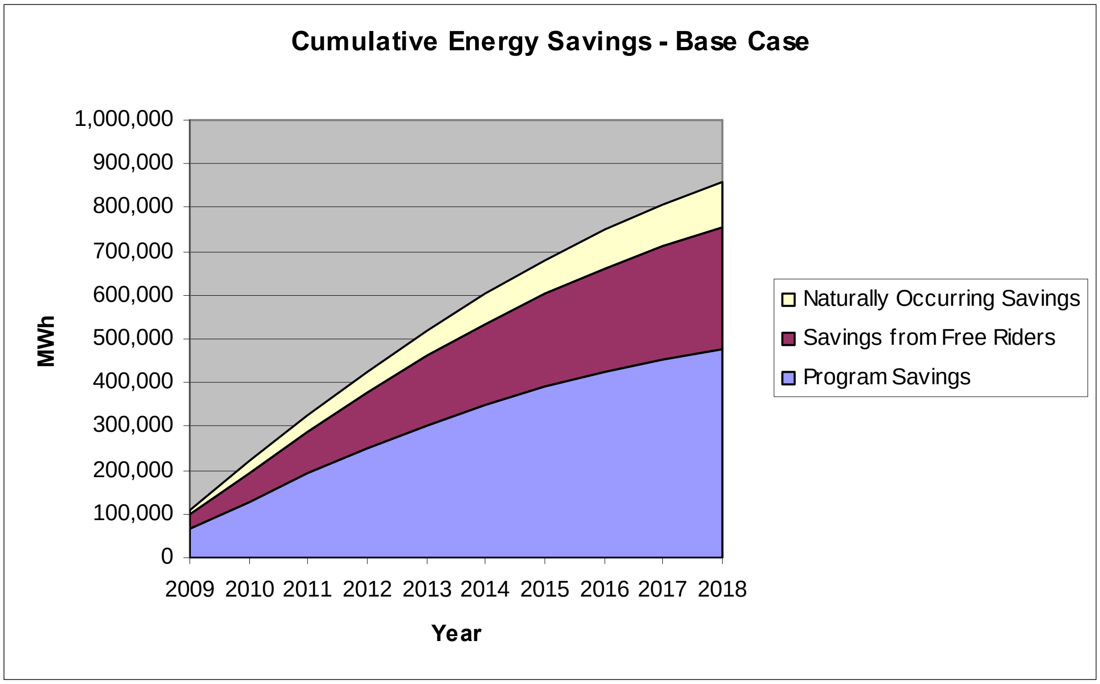
Additional Programs presented in Base Case not presented here

As shown above we developed estimates cases for both the direct load control program and the appliance recycling program that we did not model in Demand Side Assyst that are presented in Section 9.

Our model has two embedded assumptions – first once a measure is replaced – it is assumed to be efficient for the rest of the period. Secondly in this phase we are not adding any new potential technologies that may become available further out in time. In both the Base Case and the Aggressive Case as we have modeled them, after 2015 the most of the efficient retrofit measures have already been installed either through the program or by non –participants. Both cases are highly cost effective, even though they become less cost effective over time.

Figure 6-11 presents the annual gwh savings of the scenarios over time. As this figure indicates the base case remains relatively stable over time and the aggressive case slowly declines over tie after having an initial budget level of approximately $36 M.

Figure 6-11
GWH Impacts of Achievable Scenarios



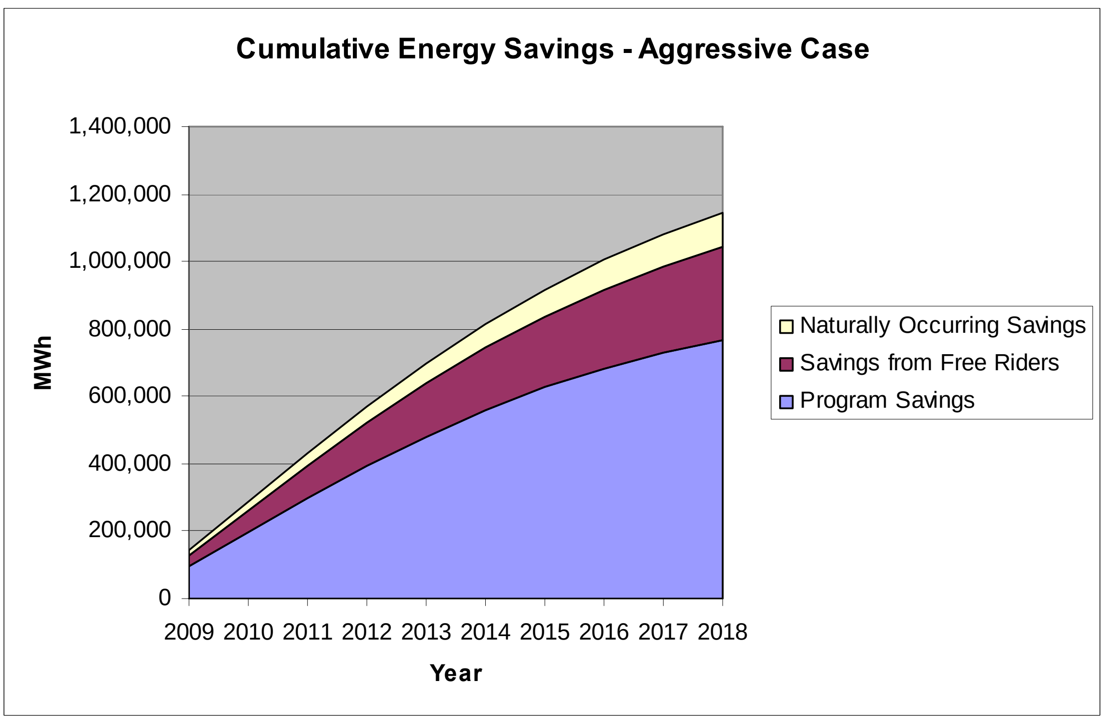


Figure 6-12 presents the overall cost effectiveness of the two achievable scenarios and indicates these cases present significant net economic benefits.

Figure 6-12
Overall Cost Effectiveness of Achievable Scenarios

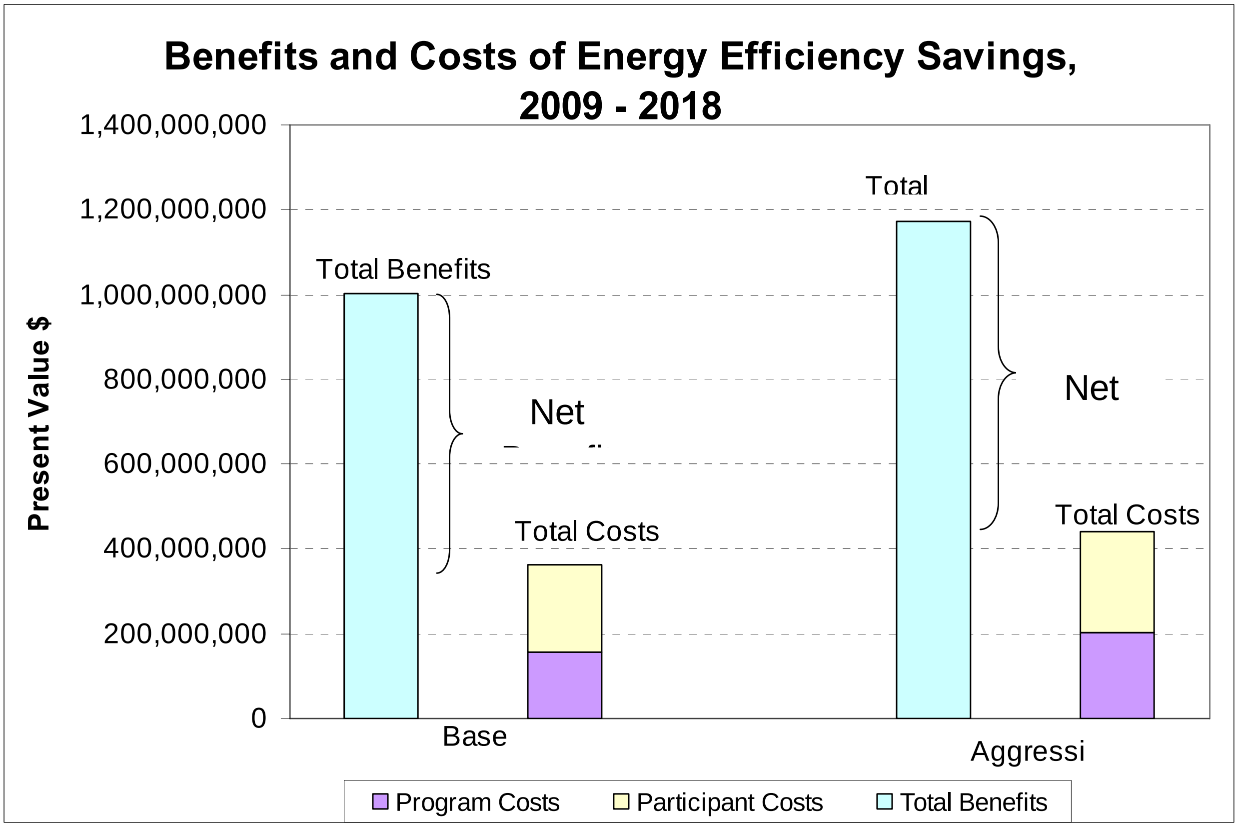
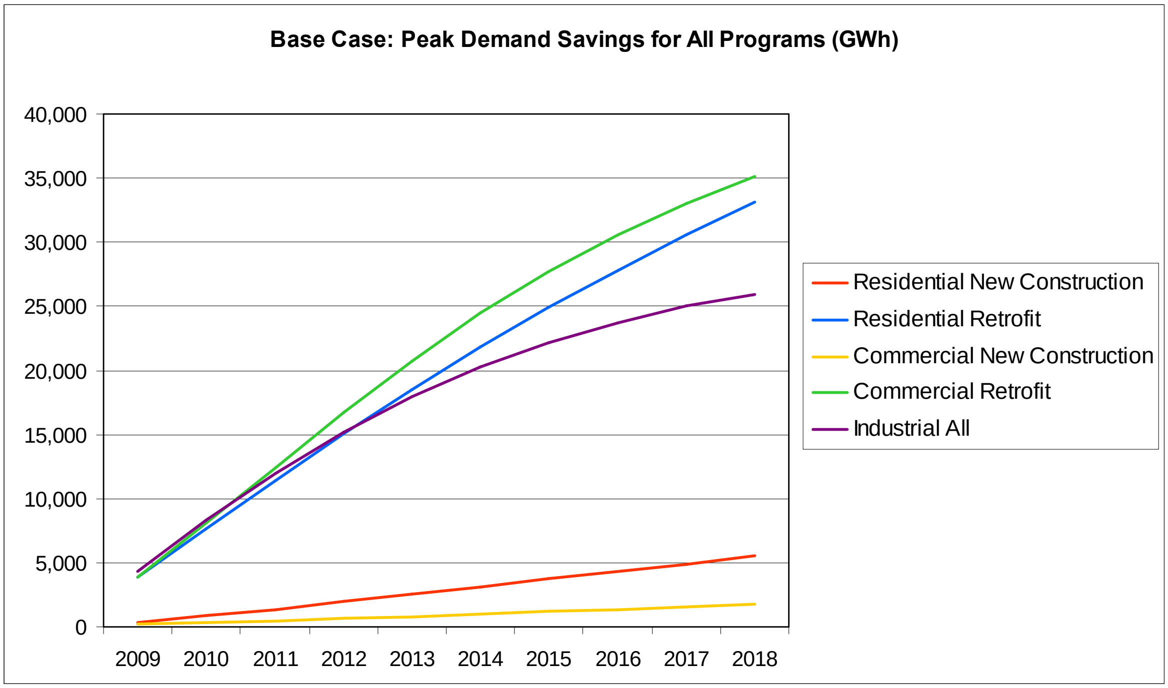


Figure 6-13 presents the base case by market sector first for KW and then for GWH.

Figure 6-13

Demand Savings- Base Case KW



Base Case – Energy Savings - GWh

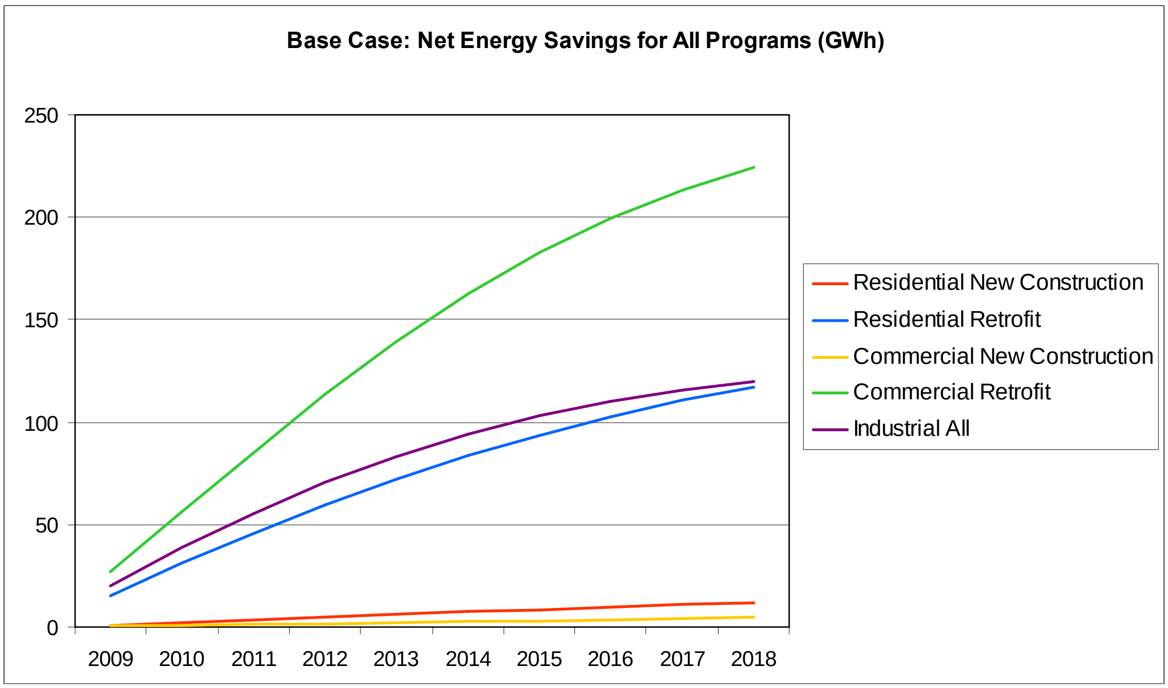
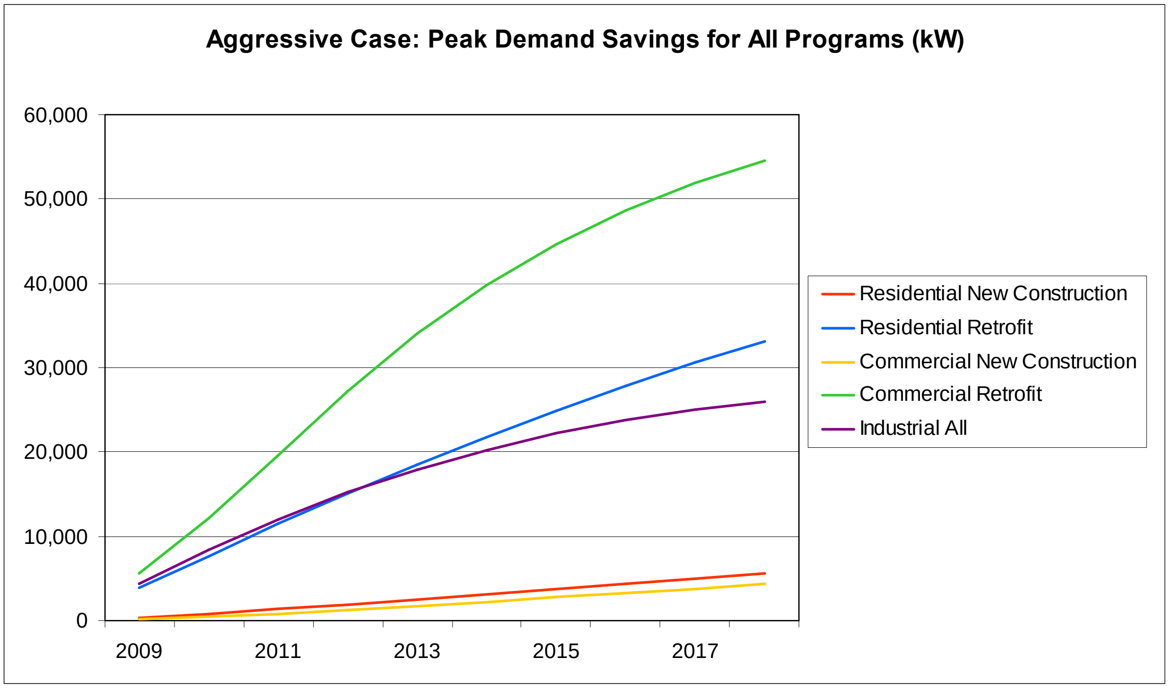
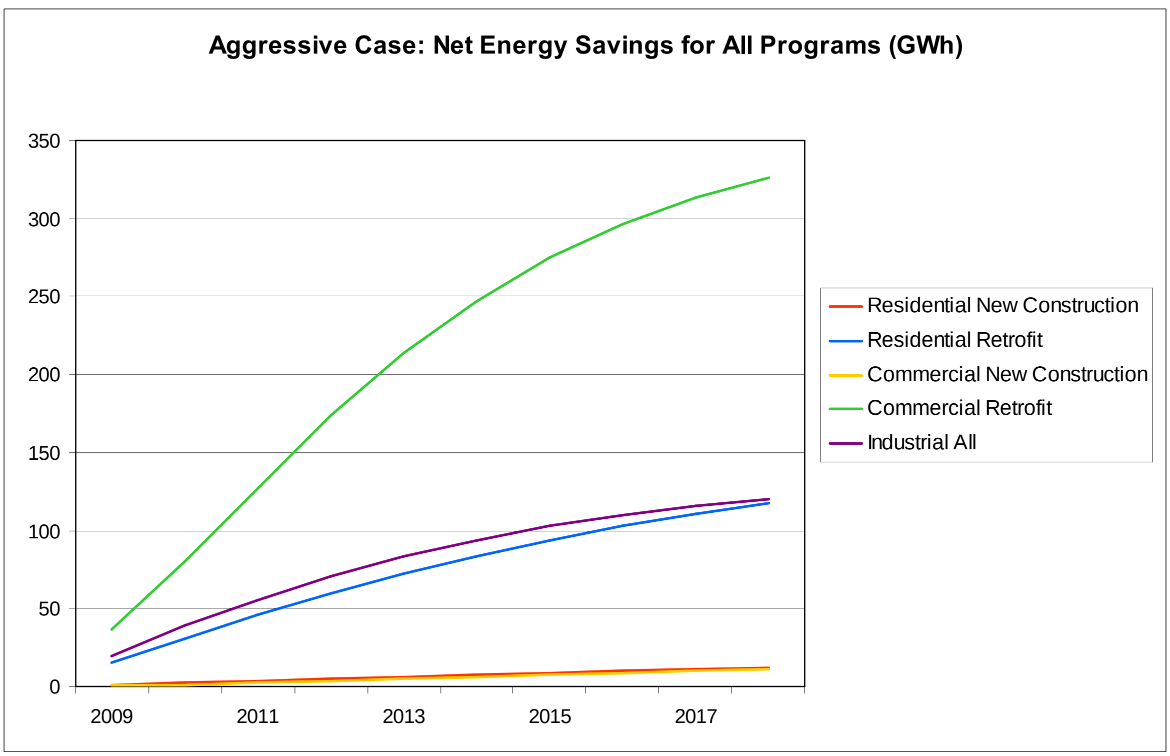


Figure 6-14 presents the demand data for the Aggressive Case.

Figure 6-14
Peak Demand Savings for All Programs





6.3 Supply curves

A common way to illustrate the amount of energy savings per dollar spent is to construct an energy-efficiency supply curve. A supply curve typically is depicted on two axes—one captures the cost per unit of saved energy (e.g., $/kWh saved), and the other shows energy savings at each level of cost. The costs of the measures are levelized over the life of the savings achieved (e.g., levelized $/kWh saved). What is important to note is that in the energy efficiency supply curve, the measures are sorted by relative cost—from least to most expensive. In addition, the energy consumption of the system being affected by the efficiency measures goes down as each measure is applied. As a result, the savings attributable to each subsequent measure decrease if the measures are interactive. For example, an occupancy sensor measure would save more at less cost per unit saved if it were applied to the base-case consumption before installation of higher efficiency lamps (e.g., premium T8 lamps). Because the premium T8 lamp is more cost-effective, however, it is applied first, reducing the energy savings potential for the occupancy sensor. Thus, in a typical EE supply curve, the base-case end-use consumption is reduced with each unit of energy efficiency that is acquired. The total end-use GWh consumption is recalculated after each measure is implemented, thus reducing the base energy available to be saved by the next measure.

Figures 6-15 to 6-17 present the energy-efficiency supply curves constructed for this study for both residential and commercial/institutional buildings. Each curve represents energy savings as a percentage of total energy consumption in Rhode Island in the year 2020. Savings potentials and levelized costs for the individual measures that comprise the supply curve are provided in Appendix A.

Figure 6-15
Residential Electric Supply Curve – Potential in 2020

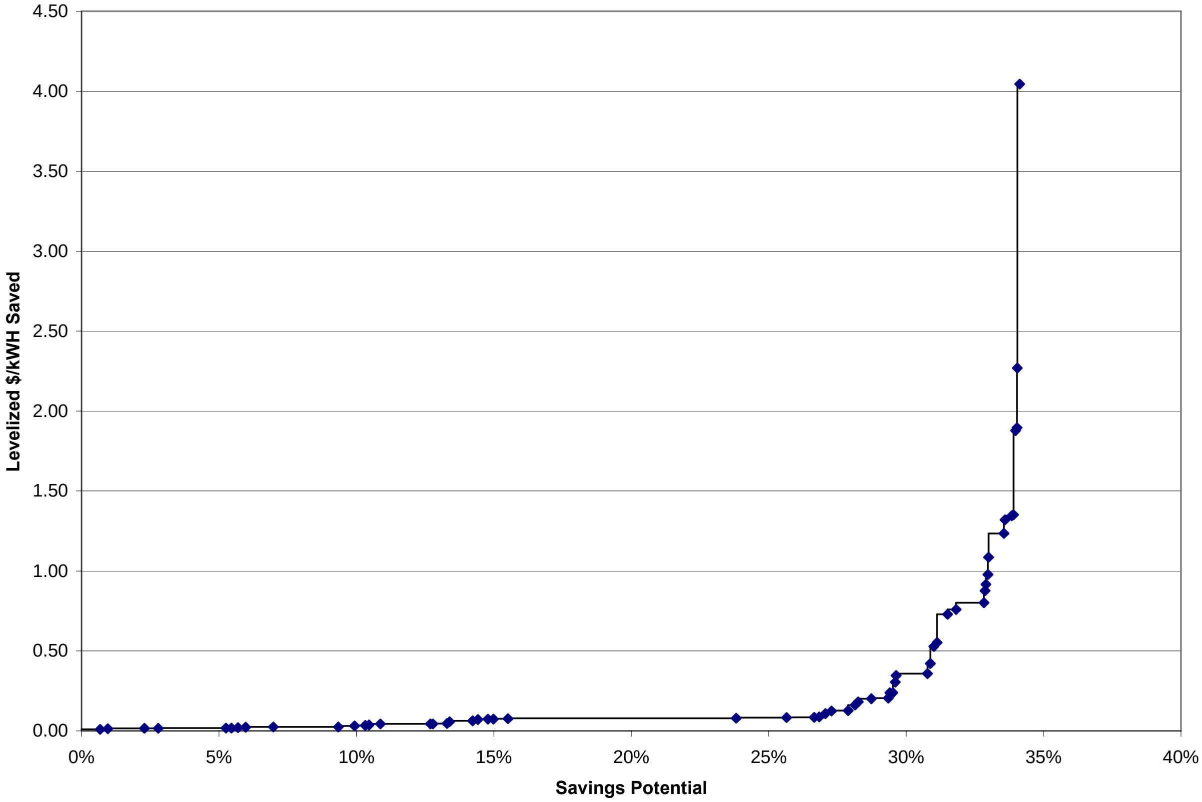


Figure 6-16
Commercial/Institutional Electric Supply Curve – Potential in 2020

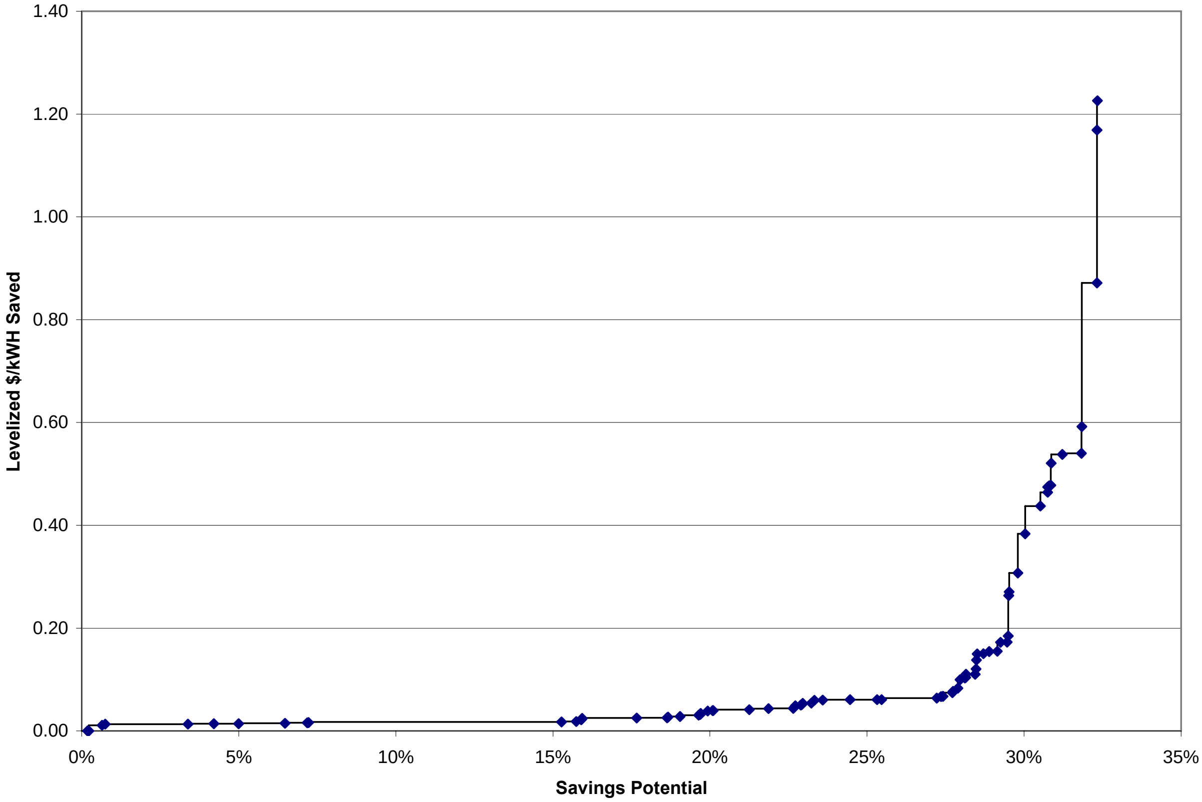
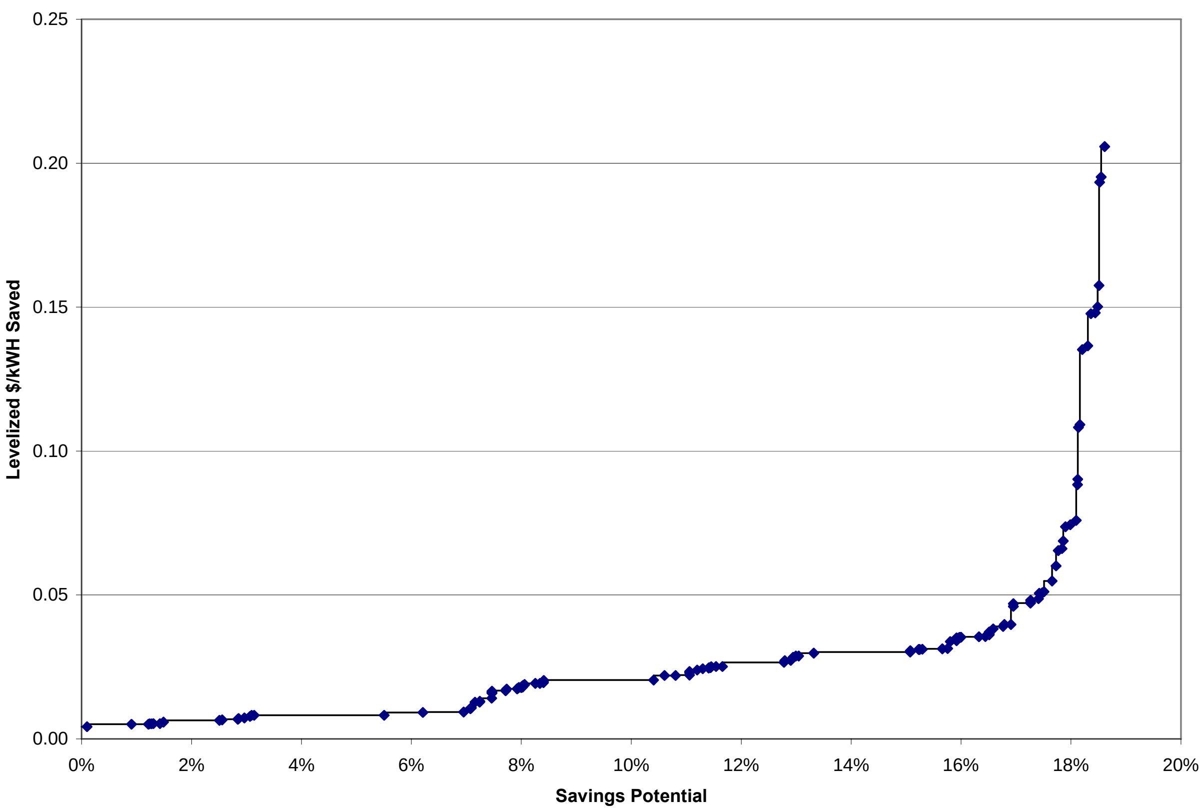


Figure 6-17
Industrial Electric Supply Curve – Potential in 2020



6.4 Measure lists

As indicated in the previous section, most of the measures we reviewed were cost effective from a total resource cost test point of view. In Tables 6-5 to 6-7 we present the top 10 most cost effective measures for each retrofit customer sector and the 10 with the most savings.

Table 6-5
Top Industrial Retrofit Measures

DSM ASSYST ADDITIVE SUPPLY ANALYSIS Vintage E Batch 1 Measure Number	Measure	Cumulative GWH Savings	Cumulative MW Savings	Marginal Energy Cost $/kWH	Marginal Capacity Cost $/kW	Total Resource Cost Test TRC
		Top 10 Measures by Total Resource Cost (Existing Industrial)				
417	O&M - Extruders/Injection Moulding	1.07	0.49	0.00	9.29	42.90
406	Gap Forming papermachine	0.40	0.10	0.01	21.86	28.06
401	Bakery - Process (Mixing) - O&M	0.23	0.05	0.01	22.78	27.89
407	High Consistency forming	0.38	0.09	0.01	22.11	27.74
104	Compressed Air- Sizing	3.34	0.64	0.01	26.47	27.41
301	Pumps - O&M	8.85	1.58	0.01	28.33	27.14
201	Fans - O&M	1.31	0.23	0.01	31.06	25.55
551	Efficient Refrigeration - Operations	0.70	0.13	0.01	31.91	22.09
101	Compressed Air-O&M	11.11	2.14	0.01	33.51	21.65
427	Drives - Optimization process (M&T)	0.50	0.16	0.01	25.87	19.56
403	Air conveying systems	0.21	0.02	0.01	62.12	18.40
		Top 10 Measures by MW Savings (Existing Industrial)				
302	Pumps - Controls	25.56	4.58	0.01	46.30	16.59
801	RET 2L4' Premium T8, 1EB	19.12	4.23	0.03	136.20	4.81
303	Pumps - System Optimization	21.88	3.91	0.02	113.82	6.76
701	Centrifugal Chiller, 0.51 kW/ton, 500 tons	2.75	2.34	0.02	26.07	11.35
101	Compressed Air-O&M	11.11	2.14	0.01	33.51	21.65
202	Fans - Controls	12.20	2.09	0.03	154.87	5.13
712	DX Packaged System, EER=10.9, 10 tons	2.38	2.02	0.01	16.63	17.80
301	Pumps - O&M	8.85	1.58	0.01	28.33	27.14
103	Compressed Air - System Optimization	8.02	1.55	0.01	48.88	14.83
802	CFL Hardwired, Modular 36W	7.69	1.54	0.01	46.09	15.31
711	DX Tune Up/ Advanced Diagnostics	1.54	1.31	0.05	57.37	5.16

Table 6-6
Top Commercial Retrofit Measures

Measure Number	Measure	GWH Savings	MW Savings	Cost $/kWH	Cost $/kW	Cost Test TRC
		Top 10 Measures by Total Resource Cost (Existing Commercial)				
181	ROB 4L4' Premium T8, 1EB	28.63	4.77	0.01	64.43	14.99
186	ROB 2L4' Premium T8, 1EB	44.24	7.43	0.01	75.71	13.23
611	PC Manual Power Management Enabling	31.10	1.95	0.01	199.82	12.21
301	Centrifugal Chiller, 0.51 kW/ton, 500 tons	18.41	10.07	0.02	30.63	12.19
612	PC Network Power Management Enabling	61.18	3.85	0.01	203.12	12.01
622	Monitor Power Management Enabling	29.21	1.84	0.01	215.55	11.32
166	CFL Hardwired, Modular 18W	23.26	4.34	0.02	126.18	11.23
161	CFL Screw-in 18W	69.78	13.01	0.02	115.10	9.89
805	Tankless Water Heater	1.70	0.04	0.01	661.39	9.67
221	High Pressure Sodium 250W Lamp	3.57	0.00	0.01	N/A	9.13
120	Lighting Control Tuneup	52.11	9.29	0.02	99.53	8.19
		Top 10 Measures by MW Savings (Existing Commercial)				
313	Window Film (Standard)	33.44	18.30	0.06	103.39	4.65
115	RET 2L4' Premium T8, 1EB, Reflector	80.44	14.51	0.02	127.02	6.58
139	Lighting Control Tuneup	80.02	14.12	0.05	291.86	4.19
161	CFL Screw-in 18W	69.78	13.01	0.02	115.10	9.89
318	Economizer	19.55	10.70	0.39	712.85	0.66
301	Centrifugal Chiller, 0.51 kW/ton, 500 tons	18.41	10.07	0.02	30.63	12.19
120	Lighting Control Tuneup	52.11	9.29	0.02	99.53	8.19
117	Occupancy Sensor, 4L4' Fluorescent Fixtures	26.11	8.55	0.46	1,399.65	0.38
186	ROB 2L4' Premium T8, 1EB	44.24	7.43	0.01	75.71	13.23
317	Optimize Controls	11.16	6.11	0.27	501.77	0.91
133	RET 2L4' Premium T8, 1EB	16.92	5.41	0.81	2,529.80	0.34

Table 6-7
Top Residential Retrofit Measures

Measure Number	Measure	GWH Savings	MW Savings	Cost $/kWH	Cost $/kW	Cost Test TRC
		Top 10 Residential Measures by Total Resource Cost (Existing Residential)				
902	High Efficiency One Speed Pool Pump (1.5 hp)	20.58	7.71	0.01	26.48	16.10
120	Ceiling R-0 to R-19 Insulation(.29)	5.76	10.53	0.07	38.91	7.93
151	Double Pane Clear Windows to Double Pane Low-E Windows	1.98	3.84	0.06	31.35	7.83
221	CFL (18-Watt integral ballast), 6.0 hr/day	40.50	4.04	0.02	162.09	7.11
508	Water Heater Blanket	14.98	1.68	0.02	145.60	6.93
211	CFL (18-Watt integral ballast), 3.0 hr/day	74.66	7.45	0.02	171.36	6.72
901	Two Speed Pool Pump (1.5 hp)	30.41	11.38	0.02	64.15	6.64
153	Ceiling R-0 to R-19 Insulation (.29)	11.32	20.69	0.07	39.44	6.55
311	Refrigerator - Early Replacement	71.61	11.62	0.02	148.16	5.09
231	ROB 2L4'T8, 1EB	8.30	0.83	0.01	131.74	4.82
113	Proper Refrigerant Charging and Air Flow	7.42	14.96	0.11	55.27	4.76
		Top 10 Residential Measures by MW Savings (Existing Residential)				
148	Window Film	19.12	35.45	1.09	589.07	0.72
601	Energy Star CW CEE Tier 1 (MEF=1.42)	251.47	32.57	0.08	612.51	1.54
150	Default Window With Sunscreen	15.24	29.58	0.25	128.76	2.28
115	Window Film	15.07	27.94	0.56	301.26	1.32
117	Double Pane Clear Windows to Double Pane Low-E Windows	11.54	22.40	0.11	54.83	4.34
153	Ceiling R-0 to R-19 Insulation (.29)	11.32	20.69	0.07	39.44	6.55
142	HE Room Air Conditioner - EER 12	9.91	19.98	0.72	354.58	0.73
116	Default Window With Sunscreen	10.28	19.95	0.29	146.94	1.89
103	17 SEER Split-System Air Conditioner	9.43	19.02	1.06	528.08	0.60
113	Proper Refrigerant Charging and Air Flow	7.42	14.96	0.11	55.27	4.76
311	Refrigerator - Early Replacement	71.61	11.62	0.02	148.16	5.09

Table 6-6 illustrates for several energy efficiency measures for the commercial sector and what the total GWh savings are, the cost of the resource, and the TRC test result (greater than 1.0 means it is cheaper than supply), as well as other results. This is the level of detailed used to obtain the study results. Table 6-8 illustrates this same information on many efficiency measures for the residential sector.

Table 6-8
Additive Supply Analysis

DSM ASSYST ADDITIVE SUPPLY ANALYSIS Vintage E Batch 1 Measure Number	Measure	Cumulative GWH Savings	Cumulative MW Savings	Cumulative Energy Cost	Cumulative Capacity Cost	Cumulative Resource Cost Test	Marginal Energy Cost $/kWH	Marginal Capacity Cost $/kW	Total Resource Cost Test TRC
114	RET 4L4' Premium T8, 1EB	10.39	2.40	1.15	1,146.73	13.40	0.11	478.03	1.29
115	RET 2L4' Premium T8, 1EB, Reflector	62.12	11.77	1.57	1,572.43	379.19	0.03	133.58	6.10
117	Occupancy Sensor, 4L4' Fluorescent Fixtures	21.83	6.90	11.79	11,790.19	6.95	0.54	1,707.81	0.32
118	Continuous Dimming, 5L4' Fluorescent Fixtures	0.52	0.03	0.02	20.55	1.46	0.04	692.04	2.80
120	Lighting Control Tuneup	34.78	6.76	0.89	887.25	187.18	0.03	131.18	5.38
133	RET 2L4' Premium T8, 1EB	17.21	5.60	15.00	14,999.79	4.93	0.87	2,676.97	0.29
134	RET 1L4' Premium T8, 1EB, Reflector OEM	10.78	2.11	0.80	802.49	31.64	0.07	380.37	2.93
136	Occupancy Sensor, 8L4' Fluorescent Fixtures	9.44	2.18	1.46	1,459.90	11.17	0.15	669.19	1.18
137	Continuous Dimming, 10L4' Fluorescent Fixtures	0.52	0.03	0.02	17.72	1.70	0.03	590.18	3.29
139	Lighting Control Tuneup	62.92	12.31	4.02	4,017.82	215.20	0.06	326.35	3.42
152	RET 2 - 2L4' Premium T8, 1EB	5.52	1.25	0.57	567.02	7.96	0.10	453.64	1.44
153	RET 2 - 1L4' Premium T8, 1EB, Reflector OEM	21.94	4.15	0.95	953.23	76.15	0.04	229.54	3.47
155	Occupancy Sensor, 4L8' Fluorescent Fixtures	28.31	5.49	1.24	1,239.90	92.35	0.04	225.80	3.26
156	Continuous Dimming, 5L8' Fluorescent Fixtures	12.80	3.99	6.89	6,888.71	4.13	0.54	1,724.92	0.32
161	CFL Screw-in 18W	288.07	55.83	5.06	5,057.10	3,190.74	0.02	90.57	11.08
166	CFL Hardwired, Modular 18W	94.51	18.35	1.26	1,255.62	1,207.84	0.01	68.44	12.78
176	High Bay T5	30.73	5.74	1.87	1,871.91	89.78	0.06	326.14	2.92
181	ROB 4L4' Premium T8, 1EB	15.33	3.05	0.17	166.90	210.68	0.01	54.73	13.75
182	Occupancy Sensor, 4L4' Fluorescent Fixtures	6.28	1.25	0.32	315.28	17.17	0.05	251.53	2.74
183	Lighting Control Tuneup	0.34	0.02	0.01	8.38	1.50	0.02	413.85	4.38
186	ROB 2L4' Premium T8, 1EB	29.29	5.79	0.41	405.38	331.57	0.01	69.96	11.32
187	Occupancy Sensor, 8L4' Fluorescent Fixtures	9.63	1.89	0.52	519.63	28.08	0.05	275.53	2.91
188	Lighting Control Tuneup	0.60	0.03	0.01	13.88	2.71	0.02	396.63	4.55
191	LED Exit Sign	5.64	1.11	0.47	468.29	8.80	0.08	423.78	1.56
221	High Pressure Sodium 250W Lamp	3.27	0.00	0.04	N/A	25.48	0.01	N/A	7.79
222	Outdoor Lighting Controls (Photocell/Timeclock)	41.15	0.37	1.69	1,692.25	106.61	0.04	4,534.66	2.59
301	Centrifugal Chiller, 0.51 kW/ton, 500 tons	16.73	10.09	0.31	308.48	183.38	0.02	30.58	10.96
302	Window Film (Standard)	2.49	1.07	0.25	248.08	4.34	0.10	231.09	1.75
303	EMS - Chiller	1.00	0.60	0.05	51.31	3.98	0.05	84.85	3.96
304	Cool Roof - Chiller	0.81	0.23	0.12	94.84	0.94	0.15	419.75	1.16
305	Chiller Tune Up/Diagnostics	1.48	0.92	0.71	707.24	1.01	0.48	764.96	0.68
306	VSD for Chiller Pumps and Towers	1.07	0.68	0.20	197.24	1.83	0.18	291.83	1.72
307	EMS Optimization	1.21	0.33	0.15	145.16	1.41	0.12	441.04	1.17
308	Economizer	5.60	3.37	0.22	220.44	28.99	0.04	65.47	5.18

Table 6-9
Additive Supply Analysis II

DSM ASSYST ADDITIVE SUPPLY ANALYSIS									
Vintage	E								
Batch	1								
Measure Number	Measure	Cumulative GWH Savings	Cumulative MW Savings	Cumulative Energy Cost	Cumulative Capacity Cost	Cumulative Resource Cost Test	Marginal Energy Cost $/kWH	Marginal Capacity Cost $/kW	Total Resource Cost Test TRC
103	17 SEER Split-System Air Conditioner	7.46	15.05	10.04	10,042.63	3.28	1.35	667.48	0.44
105	Programmable Thermostat	0.75	1.34	0.81	809.11	0.45	1.09	602.29	0.61
110	Ceiling Fans	0.75	1.12	0.26	259.97	1.06	0.35	231.35	1.41
111	Whole House Fans	1.66	2.47	3.14	3,139.72	0.34	1.90	1,269.13	0.21
112	Attic Venting	2.71	4.05	0.83	829.08	4.09	0.31	204.54	1.51
113	Proper Refrigerant Charging and Air Flow	6.65	13.41	0.83	826.75	32.55	0.12	61.63	4.89
114	Duct Repair (0.32)	3.65	7.36	0.66	664.48	16.62	0.18	90.25	4.55
115	Window Film	11.55	21.42	8.42	8,417.08	8.65	0.73	392.97	0.75
116	Default Window With Sunscreen	14.58	28.31	2.93	2,931.03	49.73	0.20	103.54	3.41
117	)ouble Pane Clear Windows to Double Pane Low-E Window:	16.04	31.14	1.23	1,228.42	109.16	0.08	39.44	6.80
118	ouble Pane Clear Windows to Double Pane Low-E2 Window	2.22	4.31	4.17	4,166.09	0.53	1.88	967.26	0.24
120	Ceiling R-0 to R-19 Insulation(.29)	5.76	10.53	0.41	409.85	45.72	0.07	38.91	7.93
121	Ceiling R-19 to R-38 Insulation (.27)	1.31	2.37	1.15	1,152.55	0.63	0.88	485.40	0.48
122	Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)	3.06	6.41	1.29	1,288.97	4.77	0.42	200.94	1.56
142	HE Room Air Conditioner - EER 12	9.33	18.82	7.08	7,084.08	6.77	0.76	376.41	0.73
143	Programmable Thermostat	1.18	2.13	1.56	1,560.10	0.46	1.32	731.99	0.39
145	Ceiling Fans	0.92	1.38	0.85	846.83	0.45	0.92	613.90	0.49
146	Whole House Fans	2.73	4.07	11.03	11,026.74	0.25	4.05	2,707.88	0.09
147	Attic Venting	3.59	5.36	1.98	1,983.66	2.58	0.55	369.84	0.72
148	Window Film	16.91	31.36	20.89	20,885.07	8.45	1.24	665.97	0.50
150	Default Window With Sunscreen	18.63	36.16	3.81	3,808.95	75.94	0.20	105.35	4.08
151	)ouble Pane Clear Windows to Double Pane Low-E Window:	2.71	5.26	0.12	120.36	37.83	0.04	22.87	13.96
152	ouble Pane Clear Windows to Double Pane Low-E2 Window	0.23	0.44	0.52	515.08	0.05	2.27	1,168.73	0.20
153	Ceiling R-0 to R-19 Insulation (.29)	11.07	20.25	0.82	815.87	70.58	0.07	40.30	6.37
154	Ceiling R-19 to R-38 Insulation (.27)	1.87	3.37	2.52	2,523.76	0.60	1.35	748.11	0.32
155	Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)	4.00	8.39	2.11	2,111.19	5.86	0.53	251.74	1.47
181	Variable Speed Furnace Fan	25.27	0.00	1.59	N/A	40.14	0.06	N/A	1.59
191	Dbl Pane Clear Windows to HE Windows	2.09	0.00	2.05	N/A	0.24	0.98	N/A	0.12
192	Ceiling R-0 to R-38 Insulation - Batts	15.63	0.00	0.73	N/A	31.62	0.05	N/A	2.02
193	Ceiling R-11 to R-38 Insulaton - Batts	3.35	0.00	0.80	N/A	1.32	0.24	N/A	0.39
194	Ceiling R-19 to R-38 Insulation - Batts	7.42	0.00	1.20	N/A	4.33	0.16	N/A	0.58
195	Wall Blow-in R-0 to R-13 Insulation	7.27	0.00	0.15	N/A	33.51	0.02	N/A	4.61
196	Infiltration Reduction (0.4)	6.92	0.00	0.75	N/A	6.07	0.11	N/A	0.88
197	Floor R-0 to R-19 Insulation-Batts	1.71	0.00	0.41	N/A	0.69	0.24	N/A	0.40
198	Programmable Thermostat	5.32	0.00	0.46	N/A	5.86	0.09	N/A	1.10
201	CFL (18-Watt integral ballast), 0.5 hr/day	8.40	0.84	0.20	197.60	25.06	0.02	235.70	2.98
211	CFL (18-Watt integral ballast), 3.0 hr/day	74.66	7.45	1.28	1,277.29	502.05	0.02	171.36	6.72
221	CFL (18-Watt integral ballast), 6.0 hr/day	40.50	4.04	0.66	655.42	287.95	0.02	162.09	7.11
231	ROB 2L4'T8, 1EB	8.30	0.83	0.11	109.18	39.99	0.01	131.74	4.82
232	RET 2L4'T8, 1EB	6.06	0.61	0.11	109.18	21.32	0.02	180.42	3.52
301	HE Refrigerator - Energy Star version of above	55.40	8.99	4.63	4,632.19	80.82	0.08	515.17	1.46
311	Refrigerator - Early Replacement	71.61	11.62	1.72	1,721.93	364.18	0.02	148.16	5.09
401	HE Freezer	17.98	2.92	0.57	571.43	68.39	0.03	195.78	3.80
501	Heat Pump Water Heater (EF=2.9)	30.64	3.43	2.62	2,616.83	40.59	0.09	762.69	1.32
502	HE Water Heater (EF=0.93)	11.87	1.33	0.40	403.76	39.43	0.03	303.75	3.32
503	Solar Water Heat	18.35	2.06	2.33	2,332.15	16.36	0.13	1,134.67	0.89
504	Tankless Water Heater	3.01	0.34	0.17	174.26	5.87	0.06	517.75	1.95
505	Low Flow Showerhead	12.70	1.42	0.55	548.04	32.94	0.04	385.24	2.59
506	Pipe Wrap	3.96	0.44	0.15	146.50	12.12	0.04	330.07	3.06
507	Faucet Aerators	6.08	0.68	0.45	449.12	9.22	0.07	659.65	1.52
508	Water Heater Blanket	14.98	1.68	0.24	244.33	103.85	0.02	145.60	6.93
601	Energy Star CW CEE Tier 1 (MEF=1.42)	251.47	32.57	19.95	19,950.47	386.93	0.08	612.51	1.54
602	Energy Star CW CEE Tier 2 (MEF=1.60)	30.74	3.98	24.66	24,657.54	4.68	0.80	6,192.90	0.15
710	High Efficiency CD (EF=3.01 w/moisture sensor)	34.63	5.04	12.43	12,428.64	12.38	0.36	2,466.39	0.36
801	Energy Star DW (EF=0.58)	54.87	5.11	2.41	2,405.22	148.42	0.04	470.39	2.71
901	Two Speed Pool Pump (1.5 hp)	30.41	11.38	0.73	730.39	202.03	0.02	64.15	6.64
902	High Efficiency One Speed Pool Pump (1.5 hp)	20.58	7.71	0.20	204.11	331.29	0.01	26.48	16.10

Complete measure lists are included in Appendix B.

7. Key Assumptions

This section presents the key assumptions that were used in the analysis of potential. These assumptions include:

Avoided Costs

Current usage and load forecast

Building Stock

7.1 Avoided costs

The avoided costs which are used to value the energy and demand saved are based on the Synapse Avoided Cost Study[12]. The avoided generation costs are presented in Table 7-1 below.

[12] Avoided Energy Supply Cost in New England - 2007 Final Report v. 1/3/08)

Table 7-1
Avoided Generation Costs

						Doc 3892	
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Avoided Trans. Capacity Value	Avoided Res. Distrib. Capacity Value
	See Note 2				Note 3		
Units / Year	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr
2008	0.115	0.081	0.105	0.076		44	128.4
2009	0.105	0.078	0.106	0.071		44	128.4
2010	0.105	0.075	0.106	0.069	68.6	44	128.4
2011	0.100	0.071	0.104	0.066	123.6	44	128.4
2012	0.101	0.073	0.104	0.069	138.3	44	128.4
2013	0.095	0.067	0.100	0.067	146.9	44	128.4
2014	0.099	0.068	0.101	0.067	146.9	44	128.4
2015	0.097	0.068	0.105	0.066	146.9	44	128.4
2016	0.099	0.070	0.107	0.070	146.9	44	128.4
2017	0.102	0.072	0.110	0.070	146.9	44	128.4
2018	0.100	0.071	0.107	0.071	146.9	44	128.4
2019	0.100	0.070	0.110	0.071	146.9	44	128.4
2020	0.100	0.072	0.112	0.072	146.9	44	128.4
2021	0.101	0.073	0.115	0.071	146.9	44	128.4
2022	0.107	0.073	0.118	0.074	146.9	44	128.4
2023	0.108	0.074	0.120	0.075	146.9	44	128.4
2024	0.110	0.075	0.121	0.076	146.9	44	128.4
2025	0.111	0.076	0.123	0.077	146.9	44	128.4
2026	0.113	0.077	0.125	0.078	146.9	44	128.4
2027	0.115	0.079	0.127	0.080	146.9	44	128.4
2028	0.116	0.080	0.128	0.081	146.9	44	128.4
2029	0.118	0.081	0.130	0.082	146.9	44	128.4
2030	0.120	0.082	0.132	0.083	146.9	44	128.4
2031	0.121	0.083	0.134	0.084	146.9	44	128.4
2032	0.123	0.084	0.136	0.086	146.9	44	128.4
2033	0.125	0.086	0.138	0.087	146.9	44	128.4
2034	0.127	0.087	0.140	0.088	146.9	44	128.4
2035	0.129	0.088	0.142	0.089	146.9	44	128.4
2036	0.130	0.089	0.144	0.091	146.9	44	128.4
2037	0.132	0.091	0.146	0.092	146.9	44	128.4
2038	0.134	0.092	0.148	0.093	146.9	44	128.4
2039	0.136	0.093	0.150	0.095	146.9	44	128.4
2040	0.138	0.095	0.153	0.096	146.9	44	128.4

We also included demand response induced pricing effect (DRIPE) in our calculations. These values are presented in Table 7-2 below:

Table 7-2
Values for DRIPE

DRIPE for Installations in 2008				
Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
0.016	0.013	0.026	0.011	
0.047	0.037	0.077	0.033	
0.044	0.035	0.072	0.032	81.6
0.027	0.021	0.044	0.019	158.6
				102
				45.3

We also included the benefit from reduced line losses. The values we used are provided below in Table 7-3 and are from National Grid.

Table 7-3
Values for Line Losses

LINE LOSSES from National Grid					
	Energy				Capacity
Sectors	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Summer Gener.
Residential	7.20%	4.00%	7.20%	4.00%	11.20%
Com/Ind	5.90%	3.00%	5.90%	3.00%	9.50%

7.2 Current Usage and load forecast

We calibrated Demand Side Assyst to existing energy usage by rate class. The data we used were provided by Narragansett and are presented below in Table 7-4:

Table 7-4
Historical and Predicted Energy and Demand

YEAR	Residential without Electric Heat	Residential with Electric Heat	Total Residential	Commercial	Industrial	Street Light	Sales for Resale	Total
	Historical and Forecast GWh Sales							
1998	2,262.902	237.531	2,500.434	2,839.409	1,428.162	61.387	0.656	6,830.048
1999	2,394.822	239.028	2,633.849	2,962.778	1,414.073	61.915	0.708	7,073.324
2000	2,365.724	241.263	2,606.986	3,089.688	1,406.947	61.693	0.711	7,166.026
2001	2,454.139	235.075	2,689.214	3,231.227	1,357.889	62.074	0.792	7,341.196
2002	2,568.084	231.217	2,799.301	3,327.314	1,325.874	62.304	0.821	7,515.614
2003	2,702.082	253.250	2,955.332	3,418.260	1,256.555	63.054	0.890	7,694.092
2004	2,727.795	243.594	2,971.390	3,489.108	1,297.438	63.480	0.864	7,822.280
2005	2,887.353	242.330	3,129.682	3,580.945	1,210.959	62.886	0.863	7,985.335
2006	2,774.630	217.694	2,992.324	3,534.610	1,141.426	63.169	0.801	7,732.329
2007	2,850.410	223.639	3,074.049	3,625.716	1,116.802	62.274	0.814	7,879.655
Forecast								
2008	2,853.711	215.929	3,069.640	3,630.370	1,100.690	62.241	0.748	7,863.688
2009	2,903.274	216.501	3,119.775	3,687.695	1,106.430	62.241	0.771	7,976.912
2010	2,963.336	211.589	3,174.926	3,762.282	1,112.737	62.241	0.789	8,112.974
2011	3,023.288	206.822	3,230.110	3,816.911	1,116.600	62.241	0.807	8,226.670
2012	3,076.236	202.092	3,278.329	3,844.969	1,117.867	62.241	0.825	8,304.230
2013	3,125.454	197.386	3,322.839	3,860.349	1,117.831	62.241	0.843	8,364.103
2014	3,172.274	192.724	3,364.998	3,872.672	1,117.819	62.241	0.861	8,418.591
2015	3,216.335	188.108	3,404.443	3,884.597	1,117.653	62.241	0.880	8,469.812
2016	3,259.067	183.538	3,442.605	3,899.082	1,117.599	62.241	0.898	8,522.424
2017	3,302.634	179.015	3,481.650	3,919.169	1,117.664	62.241	0.916	8,581.639

YEAR	Residential without Electric Heat	Residential with Electric Heat	Total Residential	Commercial	Industrial	Street Light	Sales for Resale	Total
	Historical and Forecast Customer Counts							
1998	385,036	19,230	404,266	45,846	2,576	n/a	n/a	452,688
1999	389,105	19,087	408,191	46,972	2,556	n/a	n/a	457,720
2000	390,821	18,452	409,273	50,673	2,578	n/a	n/a	462,523
2001	393,189	18,144	411,333	52,433	2,550	n/a	n/a	466,316
2002	395,216	18,603	413,819	52,819	2,473	n/a	n/a	469,111
2003	397,792	18,629	416,421	53,559	2,420	n/a	n/a	472,400
2004	399,879	18,488	418,366	54,160	2,364	n/a	n/a	474,890
2005	403,137	18,478	421,615	54,611	2,313	n/a	n/a	478,539
2006	404,564	18,325	422,888	55,172	2,222	n/a	n/a	480,283
2007	406,555	18,226	424,781	55,796	2,165	n/a	n/a	482,742
Forecast						n/a	n/a	
2008	405,908	18,023	423,932	56,037	2,117	n/a	n/a	482,086
2009	406,856	17,890	424,747	56,201	2,173	n/a	n/a	483,120
2010	408,642	17,776	426,418	56,723	2,208	n/a	n/a	485,349
2011	410,517	17,663	428,180	57,114	2,227	n/a	n/a	487,521
2012	412,566	17,549	430,115	57,299	2,234	n/a	n/a	489,648
2013	414,571	17,435	432,006	57,398	2,235	n/a	n/a	491,638
2014	416,420	17,322	433,741	57,490	2,233	n/a	n/a	493,464
2015	418,027	17,208	435,234	57,593	2,229	n/a	n/a	495,057
2016	419,380	17,094	436,474	57,732	2,225	n/a	n/a	496,432
2017	420,732	16,981	437,712	57,937	2,221	n/a	n/a	497,870

Historical and Forecast Peak Demand (MW)		
1998	1,418.4	1,134.9
1999	1,516.2	1,187.8
2000	1,464.7	1,258.4
2001	1,659.0	1,217.7
2002	1,692.1	1,203.6
2003	1,581.9	1,280.9
2004	1,618.3	1,382.9
2005	1,773.0	1,381.1
2006	1,937.9	1,298.5
2007	1,768.0	1,317.5
Forecast		
2008	1,928.4	1,366.5
2009	1,968.0	1,385.3
2010	2,007.5	1,404.5
2011	2,045.3	1,422.3
2012	2,083.3	1,439.7
2013	2,121.1	1,457.1
2014	2,158.8	1,474.4
2015	2,196.4	1,491.5
2016	2,234.2	1,508.5
2017	2,272.3	1,526.0

7.3 Building stock assumptions

7.3.1 Rhode Island Commercial Buildings

In order to obtain commercial building statistics for Rhode Island we first gathered data from the Rhode Island Research and Economic Database.[13] We generated custom industry reports to retrieve the number of commercial establishments to match up to DSM Assyst categories. This data has been gathered and placed in the tables below. Several smaller sectors were combined into one category order to match up with DSM Assyst categories.

For the average square footage of Rhode Island commercial buildings, we used statistics from the 2003 Commercial Buildings Energy Consumption Survey – Overview of Building Characteristics (CBECS)[14]. The average square feet per building is lower in New England compared to the national average. As a result, we developed a ratio to calculate the average square feet for New England and applied the ratio to the national averages for each individual sector.

For energy use per square feet, we used the 2006 data from the Commercial Buildings Energy Consumption Survey -- Electricity Consumption and Expenditure Intensities (Table C14).[15] For those sectors that are combined into one category, we averaged their collective electricity consumption per square foot. Sectors that were averaged are: Food Sales & Services, and Public Administration & Services. Data was unavailable for two categories: Administrative & Waste Management, and Arts, Entertainment, & Recreation For these two categories, the "Other" category electricity consumption per square foot numbers were applied.

For estimated energy consumption, we multiplied the average square feet for each category with the energy use per square foot.

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[13] http://www.dlt.ri.gov/rired/default.asp

[14] http://www.eia.doe.gov/emeu/cbecs/cbecs2003/introduction.html]

[15] http://www.eia.doe.gov/emeu/cbecs/cbecs2003/detailed_tables_2003/detailed_tables_2003.html#consumexpen03

7.3.2 Rhode Island Industrial Buildings

In order to obtain the number of industrial building establishments by desired category, we gathered data from the 2002 Economic Census Geographic Series.[16] We then calculated the national electricity consumption average per building using statistics from the 2002 Economic Census Industry Statistics Sampler and the 2002 Manufacturing Energy Consumption -- First Use of Energy for All Purposes (Fuel and Nonfuel).[17] We then derived sales by building type. This was then calibrated to the actual Rhode Island usage.

7.3.3 Residential Homes Data

We used the number of electric space heat and non electric space heat customers from National Grid for Rhode Island to develop the number of homes.

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[16] http://www.census.gov/econ/census02/guide/02EC_RI.HTM

[17] http://www.census.gov/econ/census02/data/industry/index.html
http://www.eia.doe.gov/emeu/mecs/mecs2002/data02/pdf/table1.1_02.pdf

8. Phase II

The goal of Phase II of the Opportunity Report is to confirm or revise the findings regarding technical, economic and achievable potential from Phase I and to provide greater detail and recommendations with regard to: 1) Existing Efficiency Measures and Resources pursued by the utility today that have a TRC greater than 1.0 but have been underinvested in and not tapped for all cost savings; 2) New Efficiency Measures and Resources that are not currently pursued by the utility efficiency programs but have a demonstrated TRC greater than 1.0 so they would generate cost savings; and 3) New Approaches to Existing Efficiency Measures and Resources that would enable a greater quantity of resource to be tapped with TRC greater than 1.0 and thus generate cost savings.

Phase II will be completed through Rhode Island on-site and phone survey research to be conducted after July 15th. The exact timing and focus of the Phase II work will be informed by results from Phase I and through direction from the EERMC.

One primary task of Phase II is to conduct 300 completed phone surveys and 150 completed site visits. The site visits can likely be reserved for C&I sectors. The residential sector may need to be further broken down into the low income, non-low income, single-family and multi-family sectors subject to direction from the EERMC.

9. Initial Estimate for new program concepts

In this section we model the possible new program areas for Rhode Island. This will be done for Appliance Recycling and Direct Load Control. Additional new areas will be modeled in Phase II. We choose these two a we thought it would be possible to get programs up and running in 2009 for both.

9.1 Appliance Recycling

We based our estimates for this program on data from one of the implementation vendors that offers this program. [18] A sample scenario is provided below. This sample was provided by JACO which is one of the vendors who offers this program. Additional information can be found in Appendix C.

[18] Several phone calls with Sam Sirkin at Jaco

2008-2010 REFRIGERATOR RECYCLING PROGRAM (RRP) SCENARIO ANALYSES

SCENARIO: 1.5% Annual Harvest Rate (AHR)

Program Assumptions		Values	Notes
Market Penetration			
Total Res. Elec Svc Accts		**424,781**	
Annual Harvest Rate (units / residential elec svc accts)		**1.5%**	pilot program = up to 0.5%; highest experienced = 3.5 to 4.0%
Measure Savings Attributes: Refrigerators			
Refrigerator Fraction of Total Program Volumes		**80%**	typical/midrange % refrigerators in JACO RRP implementations in recent years
Refrigerator Net Energy Savings (annual kWh/unit)		**681**	KEMA-Xenergy, "Measurement and Evaluation Study of 2002 Statewide Residential Appliance Recycling Program", 2/2004; value assumes 1946 gross kWh and 35% NTG (NTG corrects for full and partial free ridership, and partial year use); value is conservative relative to what will be reported for 2004-2005 program in ADM final report to be published by 12/2007
Refrigerator Net Demand Savings (avg kW)		**0.08**	based on net energy savings value and 8760 hr/yr
Measure Savings Attributes: Freezers			
Freezer Fraction of Total Program Volumes		**20%**	typical/midrange % freezers in JACO RRP implementations in recent years
Freezer Net Energy Savings (annual kWh/unit)		**897**	KEMA-Xenergy, "Measurement and Evaluation Study of 2002 Statewide Residential Appliance Recycling Program", 2/2004; value assumes 1662 gross kWh and 54% NTG (NTG corrects for full and partial free ridership, and partial year use); value is similar to what will be reported for 2004-2005 program in ADM final report to be published by 12/2007
Freezer Net Demand Savings (avg kW)		**0.10**	based on net energy savings value and 8760 hr/yr
Measure Savings Attributes: Weighted Net Avg (Refrigerator/Freezer)			
Wtd. Avg. Net Energy Savings (annual kWh/unit)		**724**	calculated based on above assumptions
Wtd. Avg. Net Demand Savings (avg kW)		**0.08**	based on net energy savings value and 8760 hr/yr
Measure Life (applic. to refigerators and freezers)		**8**	Kema, "Residential Refrigerator Recycling Ninth Year Retention Study", Study ID's 546B, 563; prepared for SCE, 7/22/2004; available from Calmac web site as study # SCE0130.01
Per-Unit Implementation Cost Assumptions			
Incentive	$	30.00	identical to 2007 incentive levels used in implementations in ID, NM, NV, UT, WA, and WY
Advertising, Marketing and PR	$	17.50	logically consistent with stipulated avg annual program volumes (typically consists primarily of newspaper ad inserts, TV commercial spots, collection truck signage, search engine marketing, internet banners, and PR event -- excludes bill stuffer costs, since utility typically handles internally
Direct Implementation	$	117.50	includes collection, transportation, recycling, CFC-11 destruction, and infrastructure (including call center, web site, check fulfillment, database/reporting, and project mgmt)
Total Implementation Cost	**$**	**165.00**	total; excludes utility program admin and EM&V more generally
Macroeconomic Assumption			
Discount Rate		**6.5%**	JACO estimate for IOU

Annual and 3-Year Total Program Metrics (note: PY = "program year")

		PY 2008		PY 2009		PY 2010		3 PY Totals	
Unit Volumes (refrigerators and freezers)		6,372		6,372		6,372		19,115	
Program Costs (excl. Prog. Admin and EM&V)									% of Total
Incentive	$	191,151	$	191,151	$	191,151	$	573,454	18%
Advertising, Marketing and PR	$	111,505	$	111,505	$	111,505	$	334,515	11%
Direct Implementation	$	748,677	$	748,677	$	748,677	$	2,246,030	71%
Total Program Implementation Costs	**$**	**1,051,333**	**$**	**1,051,333**	**$**	**1,051,333**	**$**	**3,153,999**	**100%**
Net 1st Year Load Impacts									
Annual kWh		4,614,906		4,614,906		4,614,906		13,844,717	
avg kW		527		527		527		1,580	

Detailed Year-by-Year Analysis for 3-Year Total Program Levelized Cost Calcs (assumes all units in PY X begin accruing benefits on Jan 1 of PY X)

		PY 2008		PY 2009		PY 2010		PV of Sum for 3 PY's
Program Costs	$	1,051,333	$	1,051,333	$	1,051,333	$	2,965,418
Net Annual kWh Load Impact Info		PY 2008		PY 2009		PY 2010		Sum for 3 PY's
2008		4,614,906						4,614,906
2009		4,614,906		4,614,906				9,229,811
2010		4,614,906		4,614,906		4,614,906		13,844,717
2011		4,614,906		4,614,906		4,614,906		13,844,717
2012		4,614,906		4,614,906		4,614,906		13,844,717
2013		4,614,906		4,614,906		4,614,906		13,844,717
2014		4,614,906		4,614,906		4,614,906		13,844,717
2015		4,614,906		4,614,906		4,614,906		13,844,717
2016				4,614,906		4,614,906		9,229,811
2017						4,614,906		4,614,906
Total Net Annual kWh Impacts, 2008-2017		36,919,246		36,919,246		36,919,246		110,757,738
PV of Net Annual kWh Impacts, 2008-2017								84,408,508
Overall 2008-2010 Program Levelized Costs ($/kWh)							$	0.035

This program would have a budget of approximately $1 Million per year and would save over 4,600,000 kwh annually in each year. Annual MW savings would be about 500 kw.

9.2 Small commercial and residential direct load control

This possible program area would control central AC in residences and small commercial facilities using smart thermostats. It is modeled after the City of Austin's program. KW savings per unit would be approximately .8-1 kW per unit and cost / units of $250-300.

Sample initial calculations are provided below:

AC Control - demand control, residential , multifamily and small commercial

Year	2009	2010	2011	2012	2013	2014
Number Participants	1500	2500	3000	3500	5000	5500
Net Energy Savings - kWh	0	0	0	0		
Net Peak Demand Savings - kW	1,350	3,600	6,300	9,450	13,950	18,900
Incremental Energy Savings kWh	0					
Incremental Demand Savings - kW	1,350	2,250	2,700	3,150	4,500	4,950
Program Costs - Real Dollars						
Administration	$50,000	$75,000	$75,000	$75,000	$75,000	$75,000
Marketing	$75,000	$65,000	$65,564	$67,531	$69,556	$71,643
Evaluation		$25,000	$20,000	$25,000	$25,000	$25,000
Incentives						
Other equipment costs to utility	$525,000	$875,000	$1,050,000	$1,225,000	$1,750,000	$1,925,000
Total	$650,000	$1,040,000	$1,210,564	$1,392,531	$1,919,556	$2,096,643
Avoided costs						
PV Avoided Costs	$770,766	$1,284,610	$1,541,532	$1,798,454	$2,569,220	$2,826,142
PV Annual Program Costs	$601,852	$962,963	$1,120,893	$1,289,381	$1,777,367	$1,941,336
PV Participant Costs						
TRC	1.28	1.33	1.38	1.39	1.45	1.46

Appendix A – Measure Assumptions

Energy Supply Curve - Residential New Construction Measure Number	Measure	Measure GWH Savings	Cumulative Measure GWH Savings	Percent Savings	Marginal Energy Cost $/kWH
508	Water Heater Blanket	0	0	0.57%	0.01
231	ROB 2L4'T8, 1EB	0	0	1.03%	0.01
902	High Efficiency One Speed Pool Pump (1.5 hp)	0	0	1.82%	0.01
232	RET 2L4'T8, 1EB	0	0	2.16%	0.01
221	CFL (18-Watt integral ballast), 6.0 hr/day	0	0	4.40%	0.01
211	CFL (18-Watt integral ballast), 2.5 hr/day	0	1	8.53%	0.01
201	CFL (18-Watt integral ballast), 0.5 hr/day	0	1	8.99%	0.02
505	Low Flow Showerhead	0	1	9.50%	0.02
901	Two Speed Pool Pump (1.5 hp)	0	1	10.66%	0.02
401	HE Freezer	0	1	11.34%	0.03
502	HE Water Heater (EF=0.93)	0	1	11.78%	0.04
506	Pipe Wrap	0	1	11.90%	0.04
507	Faucet Aerators	0	1	12.13%	0.04
801	Energy Star DW (EF=0.58)	0	2	14.22%	0.04
151	Double Pane Clear Windows to Double Pane Low-E Windows	0	2	14.61%	0.05
504	Tankless Water Heater	0	2	14.73%	0.06
181	Variable Speed Furnace Fan	0	2	15.69%	0.06
117	Double Pane Clear Windows to Double Pane Low-E Windows	0	2	16.15%	0.06
501	Heat Pump Water Heater (EF=2.9)	0	2	17.31%	0.08
113	Proper Refrigerant Charging and Air Flow	0	2	17.62%	0.10
503	Solar Water Heat	0	2	18.32%	0.13
114	Duct Repair (0.32)	0	2	18.48%	0.16
601	Energy Star CW CEE Tier 1 (MEF=1.42)	0	2	20.92%	0.17
150	Default Window With Sunscreen	0	2	21.51%	0.24
116	Default Window With Sunscreen	0	2	21.94%	0.26
301	HE Refrigerator - Energy Star version of above	0	3	24.04%	0.29
112	Attic Venting	0	3	24.15%	0.31
710	High Efficiency CD (EF=3.01 w/moisture sensor)	0	3	25.47%	0.36
115	Window Film	0	3	26.08%	0.52
110	Ceiling Fans	0	3	26.14%	0.53
147	Attic Venting	0	3	26.27%	0.54
91	15% above Standards	0	3	26.77%	0.61
142	HE Room Air Conditioner - EER 12	0	3	27.18%	0.65
602	Energy Star CW CEE Tier 2 (MEF=1.60)	0	3	28.60%	0.66
105	Programmable Thermostat	0	3	28.63%	0.88
148	Window Film	0	3	29.42%	1.00
145	Ceiling Fans	0	3	29.48%	1.20
143	Programmable Thermostat	0	3	29.51%	1.46
118	Double Pane Clear Windows to Double Pane Low-E2 Windows	0	3	29.59%	1.65
111	Whole House Fans	0	3	29.67%	1.88
152	Double Pane Clear Windows to Double Pane Low-E2 Windows	0	3	29.72%	2.27
103	17 SEER Split-System Air Conditioner	0	3	30.11%	2.61
122	Wall R-19 to R-21	0	3	30.12%	2.93
92	20% above Standards	0	3	30.26%	3.23
146	Whole House Fans	0	3	30.38%	4.32
155	Wall R-19 to R-21	0	3	30.39%	4.84
120	Ceiling R-30 to R-38	0	3	30.40%	9.65
121	Ceiling R-30 to R-49	0	3	30.42%	10.83
153	Ceiling R-30 to R-38	0	3	30.43%	13.85
154	Ceiling R-30 to R-49	0	3	30.46%	15.57

Energy Supply Curve - Residential Existing Homes					
Measure Number	Measure	Measure GWH Savings	Cumulative Measure GWH Savings	Percent Savings	Marginal Energy Cost $/kWH
902	High Efficiency One Speed Pool Pump (1.5 hp)	21	21	0.71%	0.01
231	ROB 2L4'T8, 1EB	8	29	1.00%	0.01
221	CFL (18-Watt integral ballast), 6.0 hr/day	41	69	2.41%	0.02
508	Water Heater Blanket	15	84	2.93%	0.02
211	CFL (18-Watt integral ballast), 3.0 hr/day	75	159	5.52%	0.02
232	RET 2L4'T8, 1EB	6	165	5.73%	0.02
195	Wall Blow-in R-0 to R-13 Insulation	8	173	6.00%	0.02
201	CFL (18-Watt integral ballast), 0.5 hr/day	8	181	6.30%	0.02
901	Two Speed Pool Pump (1.5 hp)	30	212	7.35%	0.02
311	Refrigerator - Early Replacement	72	283	9.84%	0.02
401	HE Freezer	18	301	10.46%	0.03
502	HE Water Heater (EF=0.93)	12	313	10.88%	0.03
506	Pipe Wrap	4	317	11.01%	0.04
505	Low Flow Showerhead	13	330	11.45%	0.04
192	Ceiling R-0 to R-38 Insulation - Batts	17	346	12.03%	0.04
801	Energy Star DW (EF=0.58)	55	401	13.94%	0.04
504	Tankless Water Heater	3	404	14.04%	0.06
181	Variable Speed Furnace Fan	25	430	14.92%	0.06
151	Double Pane Clear Windows to Double Pane Low-E Windows	2	432	14.99%	0.06
507	Faucet Aerators	6	438	15.20%	0.07
120	Ceiling R-0 to R-19 Insulation(.29)	5	443	15.39%	0.07
153	Ceiling R-0 to R-19 Insulation (.29)	11	454	15.76%	0.08
198	Programmable Thermostat	6	460	15.96%	0.08
301	HE Refrigerator - Energy Star version of above	55	515	17.88%	0.08
501	Heat Pump Water Heater (EF=2.9)	31	546	18.95%	0.09
196	Infiltration Reduction (0.4)	7	553	19.21%	0.10
113	Proper Refrigerant Charging and Air Flow	7	560	19.46%	0.11
117	Double Pane Clear Windows to Double Pane Low-E Windows	10	571	19.82%	0.12
503	Solar Water Heat	18	589	20.45%	0.13
194	Ceiling R-19 to R-38 Insulation - Batts	8	597	20.73%	0.15
602	Energy Star CW CEE Tier 2 (MEF=1.60)	153	750	26.06%	0.16
114	Duct Repair (0.32)	4	754	26.20%	0.17
197	Floor R-0 to R-19 Insulation-Batts	2	756	26.26%	0.22
193	Ceiling R-11 to R-38 Insulaton - Batts	4	760	26.38%	0.22
150	Default Window With Sunscreen	15	774	26.90%	0.26
122	Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)	5	779	27.06%	0.27
112	Attic Venting	3	782	27.16%	0.30
110	Ceiling Fans	1	783	27.19%	0.31
116	Default Window With Sunscreen	9	792	27.51%	0.32
710	High Efficiency CD (EF=3.01 w/moisture sensor)	35	827	28.71%	0.36
155	Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)	5	832	28.88%	0.43
115	Window Film	17	848	29.47%	0.50
147	Attic Venting	4	852	29.59%	0.54
121	Ceiling R-19 to R-38 Insulation (.27)	2	854	29.66%	0.63
142	HE Room Air Conditioner - EER 12	10	864	30.00%	0.71
105	Programmable Thermostat	1	865	30.04%	0.79
191	Dbl Pane Clear Windows to HE Windows	2	867	30.12%	0.92
145	Ceiling Fans	1	868	30.14%	1.02
103	17 SEER Split-System Air Conditioner	10	877	30.48%	1.05
148	Window Film	19	896	31.12%	1.12
154	Ceiling R-19 to R-38 Insulation (.27)	2	898	31.20%	1.18
143	Programmable Thermostat	1	899	31.24%	1.36
111	Whole House Fans	2	901	31.29%	2.09
152	Double Pane Clear Windows to Double Pane Low-E2 Windows	0	901	31.30%	2.57
118	Double Pane Clear Windows to Double Pane Low-E2 Windows	2	903	31.35%	2.69
146	Whole House Fans	2	905	31.44%	4.47

Energy Supply Curve - Commercial New Construction					
Measure Number	Measure	Measure GWH Savings	Cumulative Measure GWH Savings	Percent Savings	Marginal Energy Cost $/kWH
101	Lighting 15% More Efficient Design	1	1	6.13%	0.01
301	Cooling & Ventilation 10% More Efficient Design	1	2	10.91%	0.02
501	Refrigeration 10% More Efficient Design	0	2	11.79%	0.03
302	Cooling & Ventilation 30% More Efficient Design	2	4	19.53%	0.04
102	Lighting 25% More Efficient Design	1	5	22.49%	0.05
502	Refrigeration 20% More Efficient Design	0	5	23.08%	0.09

Energy Supply Curve - Commercial Existing Buildings					
Measure Number	Measure	Measure GWH Savings	Cumulative Measure GWH Savings	Percent Savings	Marginal Energy Cost $/kWH
621	Energy Star or Better Monitor	7	7	0.20%	0.00
631	Energy Star or Better Monitor	0	7	0.20%	0.00
641	Energy Star or Better Copier	1	9	0.24%	0.00
181	ROB 4L4' Premium T8, 1EB	29	37	1.03%	0.01
221	High Pressure Sodium 250W Lamp	4	41	1.13%	0.01
611	PC Manual Power Management Enabling	31	72	1.98%	0.01
186	ROB 2L4' Premium T8, 1EB	44	116	3.20%	0.01
612	PC Network Power Management Enabling	61	177	4.88%	0.01
622	Monitor Power Management Enabling	29	207	5.68%	0.01
805	Tankless Water Heater	2	208	5.73%	0.01
301	Centrifugal Chiller, 0.51 kW/ton, 500 tons	18	227	6.23%	0.02
120	Lighting Control Tuneup	52	279	7.67%	0.02
801	Demand controlled circulating systems	6	285	7.84%	0.02
188	Lighting Control Tuneup	1	286	7.87%	0.02
161	CFL Screw-in 18W	70	356	9.79%	0.02
183	Lighting Control Tuneup	1	357	9.81%	0.02
115	RET 2L4' Premium T8, 1EB, Reflector	80	437	12.02%	0.02
166	CFL Hardwired, Modular 18W	23	460	12.66%	0.02
911	Vending Misers (cooled machines only)	16	476	13.09%	0.02
804	Hot Water Pipe Insulation	1	477	13.11%	0.02
137	Continuous Dimming, 10L4' Fluorescent Fixtures	1	478	13.13%	0.03
651	Printer Power Management Enabling	25	503	13.82%	0.03
510	Demand Defrost Electric	2	504	13.86%	0.03
118	Continuous Dimming, 5L4' Fluorescent Fixtures	1	505	13.88%	0.03
422	Variable Speed Drive Control, 40 HP	10	515	14.15%	0.03
308	Economizer	6	521	14.32%	0.04
222	Outdoor Lighting Controls (Photocell/Timeclock)	45	566	15.57%	0.04
803	High Efficiency Water Heater (electric)	2	569	15.63%	0.04
303	EMS - Chiller	1	570	15.66%	0.05
187	Occupancy Sensor, 8L4' Fluorescent Fixtures	19	589	16.18%	0.05
182	Occupancy Sensor, 4L4' Fluorescent Fixtures	15	603	16.58%	0.05
413	Air Handler Optimization, 15 HP	11	615	16.89%	0.05
412	Variable Speed Drive Control, 15 HP	4	619	17.01%	0.05
139	Lighting Control Tuneup	80	699	19.21%	0.05
176	High Bay T5	25	724	19.90%	0.05
642	Copier Power Management Enabling	6	730	20.07%	0.05
153	RET 2 - 1L4' Premium T8, 1EB, Reflector OEM	7	737	20.27%	0.05
155	Occupancy Sensor, 4L8' Fluorescent Fixtures	6	743	20.43%	0.05
411	Fan Motor, 15hp, 1800rpm, 92.4%	1	744	20.46%	0.06
313	Window Film (Standard)	33	778	21.38%	0.06
423	Air Handler Optimization, 40 HP	3	781	21.46%	0.06
134	RET 1L4' Premium T8, 1EB, Reflector OEM	14	794	21.84%	0.06
401	Fan Motor, 5hp, 1800rpm, 89.5%	5	799	21.97%	0.06
421	Fan Motor, 40hp, 1800rpm, 94.1%	1	800	21.99%	0.07
191	LED Exit Sign	6	806	22.16%	0.08
302	Window Film (Standard)	3	809	22.24%	0.08
307	EMS Optimization	2	811	22.29%	0.09
505	Efficient compressor motor	1	812	22.32%	0.09
114	RET 4L4' Premium T8, 1EB	11	823	22.62%	0.10
509	Demand Hot Gas Defrost	0	823	22.63%	0.10
507	Floating head pressure controls	0	823	22.63%	0.11
304	Cool Roof - Chiller	1	825	22.66%	0.11
402	Variable Speed Drive Control, 5 HP	9	833	22.91%	0.13
315	Prog. Thermostat - DX	10	843	23.18%	0.13
314	Evaporative Pre-Cooler	5	848	23.31%	0.13
312	DX Packaged System, EER=10.9, 10 tons	7	855	23.51%	0.13
136	Occupancy Sensor, 8L4' Fluorescent Fixtures	10	865	23.79%	0.14
152	RET 2 - 2L4' Premium T8, 1EB	1	866	23.81%	0.14
306	VSD for Chiller Pumps and Towers	1	867	23.84%	0.17
511	Anti-sweat (humidistat) controls	1	868	23.86%	0.23
502	Strip curtains for walk-ins	1	869	23.88%	0.25
317	Optimize Controls	11	880	24.19%	0.27
316	Cool Roof - DX	11	891	24.49%	0.29
503	Night covers for display cases	0	892	24.51%	0.36
318	Economizer	20	911	25.04%	0.39
632	Monitor Power Management Enabling	0	911	25.04%	0.41
311	DX Tune Up/ Advanced Diagnostics	9	920	25.29%	0.43
305	Chiller Tune Up/Diagnostics	2	922	25.33%	0.43
501	High-efficiency fan motors	2	924	25.39%	0.45
117	Occupancy Sensor, 4L4' Fluorescent Fixtures	26	950	26.11%	0.46
506	Compressor VSD retrofit	0	950	26.12%	0.52
156	Continuous Dimming, 5L8' Fluorescent Fixtures	3	954	26.21%	0.67
133	RET 2L4' Premium T8, 1EB	17	970	26.68%	0.81
504	Evaporator fan controller for MT walk-ins	0	971	26.68%	0.92
508	Refrigeration Commissioning	0	971	26.69%	1.13

Energy Supply Curve - Industrial Buildings					
Measure Number	Measure	Measure GWH Savings	Cumulative Measure GWH Savings	Percent Savings	Marginal Energy Cost $/kWH
417	O&M - Extruders/Injection Moulding	1	1	0.10%	0.00
301	Pumps - O&M	9	10	0.91%	0.01
104	Compressed Air- Sizing	3	13	1.21%	0.01
401	Bakery - Process (Mixing) - O&M	0	13	1.24%	0.01
406	Gap Forming papermachine	0	14	1.27%	0.01
407	High Consistency forming	0	14	1.31%	0.01
201	Fans - O&M	1	16	1.43%	0.01
551	Efficient Refrigeration - Operations	1	16	1.49%	0.01
309	Pumps - ASD (6-100 hp)	3	20	1.81%	0.01
101	Compressed Air-O&M	11	31	2.83%	0.01
403	Air conveying systems	0	31	2.85%	0.01
507	Near Net Shape Casting	1	32	2.90%	0.01
109	Comp Air - ASD (6-100 hp)	1	33	3.02%	0.01
501	Bakery - Process	1	34	3.12%	0.01
510	Heating - Optimization process (M&T)	0	34	3.15%	0.01
427	Drives - Optimization process (M&T)	1	35	3.20%	0.01
302	Pumps - Controls	26	60	5.54%	0.01
802	CFL Hardwired, Modular 36W	8	68	6.24%	0.01
103	Compressed Air - System Optimization	8	76	6.98%	0.01
204	Fans- Improve components	1	78	7.10%	0.01
423	Process control	0	78	7.10%	0.01
404	Replace V-Belts	0	78	7.12%	0.01
604	Efficient processes (welding, etc.)	1	79	7.20%	0.01
603	New transformers welding	1	79	7.27%	0.01
504	Top-heating (glass)	0	79	7.27%	0.01
712	DX Packaged System, EER=10.9, 10 tons	2	82	7.49%	0.01
707	Energy Star Transformers	0	82	7.49%	0.02
607	Refinery Controls	0	82	7.49%	0.02
216	Refinery Controls	0	82	7.49%	0.02
426	Efficient drives - rolling	3	84	7.73%	0.02
717	Energy Star Transformers	0	85	7.74%	0.02
805	Energy Star Transformers	0	85	7.76%	0.02
505	Efficient electric melting	2	87	7.95%	0.02
903	Energy Star Transformers	0	87	7.96%	0.02
217	Energy Star Transformers	0	87	7.98%	0.02
431	Energy Star Transformers	0	88	8.02%	0.02
553	Energy Star Transformers	0	88	8.03%	0.02
512	Energy Star Transformers	0	88	8.05%	0.02
608	Energy Star Transformers	0	88	8.05%	0.02
429	Machinery	0	88	8.08%	0.02
430	Efficient Machinery	0	88	8.08%	0.02
102	Compressed Air - Controls	2	90	8.28%	0.02
405	Drives - EE motor	1	91	8.36%	0.02
402	O&M/drives spinning machines	1	92	8.43%	0.02
602	Efficient desalter	0	92	8.43%	0.02
315	Refinery Controls	0	92	8.43%	0.02
511	Heating - Scheduling	0	92	8.43%	0.02

Energy Supply Curve - Industrial Buildings					
Measure Number	Measure	Measure GWH Savings	Cumulative Measure GWH Savings	Percent Savings	Marginal Energy Cost $/kWH
425	Drives - Process Control	2	116	10.64%	0.02
508	Heating - Process Control	2	118	10.84%	0.02
701	Centrifugal Chiller, 0.51 kW/ton, 500 tons	3	121	11.09%	0.02
115	Refinery Controls	0	121	11.09%	0.02
902	Membranes for wastewater	0	121	11.09%	0.02
418	Extruders/injection Moulding-multipump	2	123	11.23%	0.02
715	Prog. Thermostat - DX	1	123	11.29%	0.02
210	Fans - Motor practices-1 (6-100 HP)	1	124	11.39%	0.02
316	Energy Star Transformers	0	125	11.42%	0.02
552	Optimization Refrigeration	1	126	11.53%	0.02
116	Energy Star Transformers	0	126	11.54%	0.02
214	Optimize drying process	0	126	11.55%	0.03
413	Clean Room - Controls	1	127	11.64%	0.03
509	Efficient Curing ovens	1	128	11.75%	0.03
209	Fans - ASD (6-100 hp)	1	129	11.80%	0.03
428	Drives - Scheduling	0	129	11.82%	0.03
202	Fans - Controls	12	141	12.94%	0.03
408	Optimization control PM	1	142	13.04%	0.03
605	Process control	0	142	13.04%	0.03
420	Injection Moulding - Impulse Cooling	1	143	13.09%	0.03
112	Comp Air - ASD (100+ hp)	2	145	13.26%	0.03
312	Pumps - ASD (100+ hp)	4	149	13.64%	0.03
801	RET 2L4' Premium T8, 1EB	19	168	15.40%	0.03
424	Process optimization	0	168	15.40%	0.03
502	Drying (UV/IR)	0	168	15.41%	0.03
601	Other Process Controls (batch + site)	1	169	15.47%	0.03
713	Window Film - DX	1	170	15.56%	0.03
304	Pumps - Sizing	3	173	15.81%	0.03
110	Comp Air - Motor practices-1 (6-100 HP)	1	173	15.86%	0.03
203	Fans - System Optimization	4	177	16.20%	0.03
310	Pumps - Motor practices-1 (6-100 HP)	1	178	16.31%	0.03
901	Replace V-belts	0	178	16.31%	0.04
416	Process Drives - ASD	0	178	16.33%	0.04
113	Comp Air - Motor practices-1 (100+ HP)	1	179	16.37%	0.04
212	Fans - ASD (100+ hp)	2	181	16.57%	0.04
313	Pumps - Motor practices-1 (100+ HP)	1	182	16.69%	0.04
419	Direct drive Extruders	1	183	16.76%	0.04
606	Power recovery	0	183	16.76%	0.04
215	Power recovery	0	183	16.76%	0.04
705	Chiller Tune Up/Diagnostics	0	183	16.78%	0.04
414	Clean Room - New Designs	1	184	16.85%	0.04
703	EMS - Chiller	1	185	16.97%	0.04
207	Fans - Motor practices-1 (1-5 HP)	0	186	16.99%	0.04
421	Injection Moulding - Direct drive	0	186	17.03%	0.05
415	Drives - Process Controls (batch + site)	3	189	17.34%	0.05
503	Heat Pumps - Drying	0	189	17.35%	0.05
114	Power recovery	0	189	17.35%	0.05

Energy Supply Curve - Industrial Buildings					
Measure Number	**Measure**	**Measure GWH Savings**	**Cumulative Measure GWH Savings**	**Percent Savings**	**Marginal Energy Cost $/kWH**
314	Power recovery	0	191	17.49%	0.05
706	Cooling Circ. Pumps - VSD	1	192	17.55%	0.05
107	Comp Air - Motor practices-1 (1-5 HP)	0	192	17.56%	0.05
307	Pumps - Motor practices-1 (1-5 HP)	0	192	17.59%	0.05
804	Occupancy Sensor, 8L4' Fluorescent Fixtures	2	194	17.74%	0.05
211	Fans - Replace 100+ HP motor	1	194	17.81%	0.06
702	Window Film - Chiller	1	195	17.88%	0.07
422	Efficient grinding	0	195	17.90%	0.07
213	Fans - Motor practices-1 (100+ HP)	0	196	17.94%	0.07
111	Comp Air - Replace 100+ HP motor	0	196	17.98%	0.07
311	Pumps - Replace 100+ HP motor	1	197	18.07%	0.07
716	Cool Roof - DX	1	198	18.17%	0.08
205	Fans - Replace 1-5 HP motor	0	199	18.19%	0.09
506	Intelligent extruder (DOE)	0	199	18.20%	0.09
105	Comp Air - Replace 1-5 HP motor	0	199	18.21%	0.11
305	Pumps - Replace 1-5 HP motor	0	199	18.24%	0.11
108	Comp Air - Replace 6-100 HP motor	0	200	18.28%	0.14
308	Pumps - Replace 6-100 HP motor	1	201	18.38%	0.14
208	Fans - Replace 6-100 HP motor	1	201	18.44%	0.15
714	Evaporative Pre-Cooler	1	202	18.52%	0.15
206	Fans - ASD (1-5 hp)	0	202	18.54%	0.15
704	Cool Roof - Chiller	1	203	18.59%	0.15
106	Comp Air - ASD (1-5 hp)	0	203	18.60%	0.18
306	Pumps - ASD (1-5 hp)	0	203	18.63%	0.18
803	Metal Halide, 50W	1	204	18.69%	0.21

Appendix B – Results

DSM ASSYST ADDITIVE SUPPLY ANALYSIS - Residential New Construction										
Vintage: New; Batch: 2										
Measure Number	Measure	Cumulative GWH Savings	Cumulative MW Savings	Cumulative Energy Cost	Cumulative Capacity Cost	Cumulative Resource Cost Test	Marginal Energy Cost $/kWH	Marginal Capacity Cost $/kW	Total Resource Cost Test TRC
91	15% above Standards	0.05	0.14	0.03	33.26	0.05	0.61	245.61	0.98
92	20% above Standards	0.02	0.04	0.05	49.88	0.00	3.23	1,300.30	0.19
103	17 SEER Split-System Air Conditioner	0.04	0.11	0.11	113.16	0.01	2.61	1,051.00	0.27
105	Programmable Thermostat	0.00	0.01	0.00	2.89	0.00	0.88	378.83	1.09
110	Ceiling Fans	0.01	0.01	0.00	3.25	0.01	0.53	258.06	1.19
111	Whole House Fans	0.01	0.02	0.02	16.05	0.00	1.88	906.49	0.26
112	Attic Venting	0.01	0.02	0.00	3.53	0.02	0.31	148.29	2.05
113	Proper Refrigerant Charging and Air Flow	0.03	0.08	0.00	3.47	0.19	0.10	41.72	5.81
114	Duct Repair (0.32)	0.02	0.04	0.00	2.79	0.09	0.16	62.97	5.22
115	Window Film	0.07	0.16	0.04	35.35	0.11	0.52	220.53	1.65
116	Default Window With Sunscreen	0.05	0.11	0.01	12.17	0.12	0.26	106.10	2.60
117	Double Pane Clear Windows to Double Pane Low-E Windows	0.05	0.12	0.00	3.28	0.43	0.06	26.65	8.48
118	Double Pane Clear Windows to Double Pane Low-E2 Windows	0.01	0.02	0.01	14.86	0.00	1.65	677.92	0.32
120	Ceiling R-30 to R-38	0.00	0.00	0.01	9.14	0.00	9.65	4,118.41	0.05
121	Ceiling R-30 to R-49	0.00	0.00	0.02	19.86	0.00	10.83	4,653.92	0.05
122	Wall R-19 to R-21	0.00	0.00	0.00	3.05	0.00	2.93	1,153.77	0.16
142	HE Room Air Conditioner - EER 12	0.05	0.11	0.03	29.75	0.04	0.65	262.72	0.88
143	Programmable Thermostat	0.00	0.01	0.01	5.25	0.00	1.46	630.53	0.42
145	Ceiling Fans	0.01	0.01	0.01	7.73	0.00	1.20	577.84	0.46
146	Whole House Fans	0.01	0.03	0.06	56.41	0.00	4.32	2,087.06	0.11
147	Attic Venting	0.01	0.03	0.01	8.02	0.01	0.54	259.98	0.96
148	Window Film	0.09	0.21	0.09	87.72	0.10	1.00	422.65	1.11
150	Default Window With Sunscreen	0.06	0.16	0.02	15.81	0.21	0.24	100.50	3.20
151	Double Pane Clear Windows to Double Pane Low-E Windows	0.04	0.11	0.00	2.37	0.50	0.05	22.40	11.36
152	Double Pane Clear Windows to Double Pane Low-E2 Windows	0.00	0.01	0.01	10.82	0.00	2.27	933.84	0.23
153	Ceiling R-30 to R-38	0.00	0.00	0.03	26.22	0.00	13.85	5,911.62	0.03
154	Ceiling R-30 to R-49	0.00	0.01	0.05	53.41	0.00	15.57	6,689.65	0.03
155	Wall R-19 to R-21	0.00	0.00	0.01	7.58	0.00	4.84	1,904.74	0.10
181	Variable Speed Furnace Fan	0.11	0.00	0.01	6.66	0.17	0.06	2,394.94	1.64
201	CFL (18-Watt integral ballast), 0.5 hr/day	0.05	0.01	0.00	1.01	0.17	0.02	196.79	3.26
211	CFL (18-Watt integral ballast), 2.5 hr/day	0.46	0.05	0.01	6.30	3.46	0.01	138.33	7.59
221	CFL (18-Watt integral ballast), 6.0 hr/day	0.25	0.02	0.00	3.34	1.92	0.01	135.33	7.76
231	ROB 2L4'T8, 1EB	0.05	0.01	0.00	0.46	0.35	0.01	89.65	6.86
232	RET 2L4'T8, 1EB	0.04	0.00	0.00	0.46	0.19	0.01	122.76	5.01
301	HE Refrigerator - Energy Star version of above	0.23	0.04	0.07	67.74	0.10	0.29	1,793.65	0.41
401	HE Freezer	0.08	0.01	0.00	2.40	0.28	0.03	195.78	3.75
501	Heat Pump Water Heater (EF=2.9)	0.13	0.01	0.01	10.92	0.17	0.08	757.87	1.32
502	HE Water Heater (EF=0.93)	0.05	0.01	0.00	1.70	0.15	0.04	316.50	3.16
503	Solar Water Heat	0.08	0.01	0.01	9.85	0.07	0.13	1,136.79	0.88
504	Tankless Water Heater	0.01	0.00	0.00	0.73	0.02	0.06	527.43	1.89
505	Low Flow Showerhead	0.06	0.01	0.00	1.18	0.29	0.02	188.05	5.25
506	Pipe Wrap	0.01	0.00	0.00	0.51	0.04	0.04	347.88	2.88
507	Faucet Aerators	0.03	0.00	0.00	1.07	0.07	0.04	366.49	2.70
508	Water Heater Blanket	0.06	0.01	0.00	0.41	1.09	0.01	57.72	17.28
601	Energy Star CW CEE Tier 1 (MEF=1.42)	0.27	0.03	0.05	46.84	0.18	0.17	1,342.63	0.68
602	Energy Star CW CEE Tier 2 (MEF=1.60)	0.16	0.02	0.10	103.56	0.03	0.66	5,106.94	0.20
710	High Efficiency CD (EF=3.01 w/moisture sensor)	0.15	0.02	0.05	52.20	0.05	0.36	2,466.39	0.35
801	Energy Star DW (EF=0.58)	0.23	0.02	0.01	10.10	0.61	0.04	470.39	2.66
901	Two Speed Pool Pump (1.5 hp)	0.13	0.05	0.00	3.07	0.83	0.02	64.15	6.52
902	High Efficiency One Speed Pool Pump (1.5 hp)	0.09	0.03	0.00	0.86	1.37	0.01	26.48	15.80

DSM ASSYST ADDITIVE SUPPLY ANALYSIS - Residential Existing Construction

Vintage E
Batch 2

Measure Number	Measure	Cumulative GWH Savings	Cumulative MW Savings	Cumulative Energy Cost	Cumulative Capacity Cost	Cumulative Resource Cost Test	Marginal Energy Cost $/kWH	Marginal Capacity Cost $/kW	Total Resource Cost Test TRC
103	17 SEER Split-System Air Conditioner	9.56	23.73	10.04	10,042.63	6.98	1.05	423.29	0.73
105	Programmable Thermostat	1.02	2.38	0.81	809.11	1.20	0.79	339.97	1.17
110	Ceiling Fans	0.83	1.71	0.26	259.97	1.55	0.31	151.70	1.87
111	Whole House Fans	1.50	3.11	3.14	3,139.72	0.37	2.09	1,010.18	0.25
112	Attic Venting	2.77	5.73	0.83	829.08	5.72	0.30	144.78	2.06
113	Proper Refrigerant Charging and Air Flow	7.43	18.45	0.83	826.75	43.28	0.11	44.82	5.82
114	Duct Repair (0.32)	3.93	9.75	0.66	664.48	20.79	0.17	68.14	5.29
115	Window Film	16.75	39.61	8.42	8,417.08	25.78	0.50	212.53	1.54
116	Default Window With Sunscreen	9.27	22.51	2.93	2,931.03	21.42	0.32	130.21	2.31
117	Double Pane Clear Windows to Double Pane Low-E Windows	10.17	24.69	1.23	1,228.42	50.19	0.12	49.75	4.94
118	Double Pane Clear Windows to Double Pane Low-E2 Windows	1.55	3.77	4.17	4,166.09	0.32	2.69	1,106.27	0.20
120	Ceiling R-0 to R-19 Insulation(.29)	5.50	12.88	0.41	409.85	52.35	0.07	31.82	9.52
121	Ceiling R-19 to R-38 Insulation (.27)	1.83	4.27	1.15	1,152.55	1.89	0.63	270.20	1.03
122	Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)	4.81	12.20	1.29	1,288.97	15.75	0.27	105.63	3.28
142	HE Room Air Conditioner - EER 12	9.96	24.73	7.08	7,084.08	8.85	0.71	286.44	0.89
143	Programmable Thermostat	1.14	2.66	1.56	1,560.10	0.54	1.36	586.81	0.47
145	Ceiling Fans	0.83	1.71	0.85	846.83	0.48	1.02	493.78	0.58
146	Whole House Fans	2.47	5.10	11.03	11,026.74	0.27	4.47	2,160.23	0.11
147	Attic Venting	3.65	7.55	1.98	1,983.66	3.58	0.54	262.60	0.98
148	Window Film	18.61	44.00	20.89	20,885.07	16.25	1.12	474.65	0.87
150	Default Window With Sunscreen	14.75	35.81	3.81	3,808.95	41.48	0.26	106.37	2.81
151	Double Pane Clear Windows to Double Pane Low-E Windows	1.91	4.63	0.12	120.36	18.08	0.06	25.99	9.48
152	Double Pane Clear Windows to Double Pane Low-E2 Windows	0.20	0.49	0.52	515.08	0.04	2.57	1,057.89	0.21
153	Ceiling R-0 to R-19 Insulation (.29)	10.73	25.15	0.82	815.87	83.41	0.08	32.44	7.77
154	Ceiling R-19 to R-38 Insulation (.27)	2.15	4.99	2.52	2,523.76	1.18	1.18	505.49	0.55
155	Wall 2x4 R-0 to Blow-In R-13 Insulation (0.14)	4.91	12.47	2.11	2,111.19	13.51	0.43	169.25	2.75
181	Variable Speed Furnace Fan	25.27	0.66	1.59	1,585.89	45.50	0.06	2,394.94	1.80
191	Dbl Pane Clear Windows to HE Windows	2.23	0.09	2.05	2,048.74	0.32	0.92	22,333.51	0.14
192	Ceiling R-0 to R-38 Insulation - Batts	16.68	0.68	0.73	730.87	41.82	0.04	1,067.60	2.51
193	Ceiling R-11 to R-38 Insulaton - Batts	3.58	0.15	0.80	804.52	1.75	0.22	5,479.05	0.49
194	Ceiling R-19 to R-38 Insulation - Batts	7.91	0.32	1.20	1,201.13	5.73	0.15	3,697.15	0.72
195	Wall Blow-in R-0 to R-13 Insulation	7.76	0.32	0.15	149.57	44.32	0.02	469.68	5.71
196	Infiltration Reduction (0.4)	7.39	0.30	0.75	745.28	8.03	0.10	2,458.12	1.09
197	Floor R-0 to R-19 Insulation-Batts	1.83	0.08	0.41	406.55	0.91	0.22	5,420.61	0.50
198	Programmable Thermostat	5.68	0.23	0.46	462.73	7.75	0.08	1,984.54	1.36
201	CFL (18-Watt integral ballast), 0.5 hr/day	8.40	0.84	0.20	197.60	26.93	0.02	235.70	3.21
211	CFL (18-Watt integral ballast), 3.0 hr/day	74.66	7.45	1.28	1,277.29	539.41	0.02	171.36	7.22
221	CFL (18-Watt integral ballast), 6.0 hr/day	40.50	4.04	0.66	655.42	309.38	0.02	162.09	7.64
231	ROB 2L4'T8, 1EB	8.30	0.83	0.11	109.18	42.96	0.01	131.74	5.18
232	RET 2L4'T8, 1EB	6.06	0.61	0.11	109.18	22.91	0.02	180.42	3.78
301	HE Refrigerator - Energy Star version of above	55.40	8.99	4.63	4,632.19	86.57	0.08	515.17	1.56
311	Refrigerator - Early Replacement	71.61	11.62	1.72	1,721.93	390.12	0.02	148.16	5.45
401	HE Freezer	17.98	2.92	0.57	571.43	73.26	0.03	195.78	4.07
501	Heat Pump Water Heater (EF=2.9)	30.64	3.43	2.62	2,616.83	43.71	0.09	762.69	1.43
502	HE Water Heater (EF=0.93)	11.87	1.33	0.40	403.76	42.46	0.03	303.75	3.58
503	Solar Water Heat	18.35	2.06	2.33	2,332.15	17.62	0.13	1,134.67	0.96
504	Tankless Water Heater	3.01	0.34	0.17	174.26	6.32	0.06	517.75	2.10
505	Low Flow Showerhead	12.70	1.42	0.55	548.04	35.47	0.04	385.24	2.79
506	Pipe Wrap	3.96	0.44	0.15	146.50	13.05	0.04	330.07	3.29
507	Faucet Aerators	6.08	0.68	0.45	449.12	9.93	0.07	659.65	1.63
508	Water Heater Blanket	14.98	1.68	0.24	244.33	111.84	0.02	145.60	7.46
602	Energy Star CW CEE Tier 2 (MEF=1.60)	153.48	19.88	24.66	24,657.54	125.19	0.16	1,240.32	0.82
710	High Efficiency CD (EF=3.01 w/moisture sensor)	34.63	5.04	12.43	12,428.64	13.26	0.36	2,466.39	0.38
801	Energy Star DW (EF=0.58)	54.87	5.11	2.41	2,405.22	159.87	0.04	470.39	2.91
901	Two Speed Pool Pump (1.5 hp)	30.41	11.38	0.73	730.39	214.65	0.02	64.15	7.06
902	High Efficiency One Speed Pool Pump (1.5 hp)	20.58	7.71	0.20	204.11	351.98	0.01	26.48	17.10

DSM ASSYST ADDITIVE SUPPLY ANALYSIS - Commercial New Construction

Vintage N
Batch 2

Measure Number	Measure	Cumulative GWH Savings	Cumulative MW Savings	Cumulative Energy Cost	Cumulative Capacity Cost	Cumulative Resource Cost Test	Marginal Energy Cost $/kWH	Marginal Capacity Cost $/kW	Total Resource Cost Test TRC
101	#N/A	1.26	0.22	0.01	14.97	15.19	0.01	68.99	12.06
102	#N/A	0.61	0.10	0.03	31.52	1.67	0.05	301.72	2.76
301	#N/A	0.98	0.54	0.01	14.97	13.04	0.02	27.86	13.27
302	#N/A	1.59	0.87	0.07	67.37	7.60	0.04	77.39	4.78
501	#N/A	0.18	0.01	0.01	5.08	0.66	0.03	553.24	3.66
502	#N/A	0.12	0.01	0.01	11.24	0.14	0.09	1,788.80	1.13

DSM ASSYST ADDITIVE SUPPLY ANALYSIS - Commercial Existing Buildings									
Vintage E							Marginal	Marginal	Total
Batch 2		Cumulative	Cumulative	Cumulative	Cumulative	Cumulative	Energy	Capacity	Resource
Measure		GWH	MW	Energy	Capacity	Resource	Cost	Cost	Cost Test
Number	Measure	Savings	Savings	Cost	Cost	Cost Test	$/kWH	$/kW	TRC
114	RET 4L4' Premium T8, 1EB	11.01	2.27	1.09	1,087.96	16.25	0.10	478.72	1.48
115	RET 2L4' Premium T8, 1EB, Reflector	80.44	14.51	1.84	1,843.37	529.60	0.02	127.02	6.58
117	Occupancy Sensor, 4L4' Fluorescent Fixtures	26.11	8.55	11.97	11,969.78	9.86	0.46	1,399.65	0.38
118	Continuous Dimming, 5L4' Fluorescent Fixtures	0.77	0.04	0.02	23.54	2.90	0.03	617.13	3.75
120	Lighting Control Tuneup	52.11	9.29	0.92	924.35	426.59	0.02	99.53	8.19
133	RET 2L4' Premium T8, 1EB	16.92	5.41	13.68	13,677.12	5.82	0.81	2,529.80	0.34
134	RET 1L4' Premium T8, 1EB, Reflector OEM	13.71	2.42	0.82	823.24	49.35	0.06	340.18	3.60
136	Occupancy Sensor, 8L4' Fluorescent Fixtures	9.89	1.97	1.34	1,343.63	13.63	0.14	683.02	1.38
137	Continuous Dimming, 10L4' Fluorescent Fixtures	0.73	0.04	0.02	19.09	3.19	0.03	537.57	4.39
139	Lighting Control Tuneup	80.02	14.12	4.12	4,121.73	335.68	0.05	291.86	4.19
152	RET 2 - 2L4' Premium T8, 1EB	0.91	0.21	0.13	130.82	1.14	0.14	625.67	1.26
153	RET 2 - 1L4' Premium T8, 1EB, Reflector OEM	7.04	1.39	0.37	374.57	25.22	0.05	269.41	3.59
155	Occupancy Sensor, 4L8' Fluorescent Fixtures	5.95	1.18	0.32	317.69	21.21	0.05	270.31	3.57
156	Continuous Dimming, 5L8' Fluorescent Fixtures	3.28	1.17	2.21	2,211.80	1.21	0.67	1,895.92	0.37
161	CFL Screw-in 18W	69.78	13.01	1.50	1,497.44	690.10	0.02	115.10	9.89
166	CFL Hardwired, Modular 18W	23.26	4.34	0.55	547.20	261.28	0.02	126.18	11.23
176	High Bay T5	25.21	5.05	1.31	1,307.50	71.24	0.05	259.13	2.83
181	ROB 4L4' Premium T8, 1EB	28.63	4.77	0.31	307.63	429.05	0.01	64.43	14.99
182	Occupancy Sensor, 4L4' Fluorescent Fixtures	14.52	2.31	0.69	691.68	42.06	0.05	299.14	2.90
183	Lighting Control Tuneup	0.69	0.03	0.02	15.15	3.63	0.02	486.49	5.28
186	ROB 2L4' Premium T8, 1EB	44.24	7.43	0.56	562.14	585.39	0.01	75.71	13.23
187	Occupancy Sensor, 8L4' Fluorescent Fixtures	18.93	3.01	0.88	881.71	61.18	0.05	292.55	3.23
188	Lighting Control Tuneup	0.97	0.04	0.02	19.58	5.65	0.02	438.19	5.81
191	LED Exit Sign	6.20	1.06	0.47	468.29	10.95	0.08	440.92	1.76
221	High Pressure Sodium 250W Lamp	3.57	0.00	0.04	N/A	32.57	0.01	N/A	9.13
222	Outdoor Lighting Controls (Photocell/Timeclock)	45.26	0.46	1.69	1,692.25	139.08	0.04	3,698.43	3.07
301	Centrifugal Chiller, 0.51 kW/ton, 500 tons	18.41	10.07	0.31	308.48	224.40	0.02	30.63	12.19
302	Window Film (Standard)	2.97	1.05	0.25	248.08	6.11	0.08	236.32	2.06
303	EMS - Chiller	1.10	0.60	0.05	51.31	4.87	0.05	84.93	4.41
304	Cool Roof - Chiller	1.10	0.23	0.12	94.84	1.73	0.11	419.04	1.58
305	Chiller Tune Up/Diagnostics	1.63	0.89	0.71	707.24	1.21	0.43	792.13	0.74
306	VSD for Chiller Pumps and Towers	1.18	0.64	0.20	197.24	2.17	0.17	306.70	1.85
307	EMS Optimization	1.61	0.33	0.15	145.16	2.56	0.09	435.49	1.58
308	Economizer	6.19	3.39	0.22	220.44	35.87	0.04	65.11	5.80
311	DX Tune Up/ Advanced Diagnostics	8.83	4.83	3.76	3,761.67	21.55	0.43	778.98	2.44
312	DX Packaged System, EER=10.9, 10 tons	7.31	3.38	0.98	981.52	10.78	0.13	290.27	1.47
313	Window Film (Standard)	33.44	18.30	1.89	1,891.94	155.46	0.06	103.39	4.65
314	Evaporative Pre-Cooler	4.70	0.97	0.61	612.62	5.29	0.13	631.86	1.13
315	Prog. Thermostat - DX	10.15	2.10	1.32	1,318.63	13.58	0.13	629.36	1.34
316	Cool Roof - DX	11.10	2.29	3.16	2,783.97	12.95	0.29	1,215.14	1.17
317	Optimize Controls	11.16	6.11	3.06	3,064.91	10.19	0.27	501.77	0.91
318	Economizer	19.55	10.70	7.62	7,624.14	12.96	0.39	712.85	0.66
401	Fan Motor, 5hp, 1800rpm, 89.5%	5.04	0.35	0.31	306.63	10.49	0.06	888.63	2.08
402	Variable Speed Drive Control, 5 HP	8.75	0.16	1.10	1,097.85	7.87	0.13	6,768.39	0.90
411	Fan Motor, 15hp, 1800rpm, 92.4%	1.25	0.09	0.07	69.03	2.82	0.06	806.78	2.26
412	Variable Speed Drive Control, 15 HP	4.32	0.08	0.22	218.12	8.72	0.05	2,724.77	2.02
413	Air Handler Optimization, 15 HP	11.33	0.21	0.56	555.62	24.82	0.05	2,643.93	2.19
421	Fan Motor, 40hp, 1800rpm, 94.1%	0.59	0.04	0.04	42.93	0.99	0.07	1,063.58	1.67
422	Variable Speed Drive Control, 40 HP	9.80	0.18	0.32	317.01	31.93	0.03	1,744.11	3.26
423	Air Handler Optimization, 40 HP	2.80	0.05	0.16	158.44	5.18	0.06	3,056.38	1.85
501	High-efficiency fan motors	2.20	0.11	0.98	984.26	0.51	0.45	8,736.24	0.23
502	Strip curtains for walk-ins	0.58	0.03	0.14	143.89	0.24	0.25	4,858.58	0.42
503	Night covers for display cases	0.49	0.00	0.18	N/A	0.12	0.36	N/A	0.25
504	Evaporator fan controller for MT walk-ins	0.07	0.00	0.06	N/A	0.01	0.92	N/A	0.10
505	Efficient compressor motor	1.11	0.06	0.10	104.36	1.21	0.09	1,843.12	1.10
506	Compressor VSD retrofit	0.41	0.01	0.21	212.83	0.08	0.52	19,457.50	0.19
507	Floating head pressure controls	0.35	0.00	0.04	N/A	0.29	0.11	N/A	0.83
508	Refrigeration Commissioning	0.42	0.02	0.48	478.62	0.04	1.13	22,031.98	0.09
509	Demand Hot Gas Defrost	0.16	0.01	0.02	15.85	0.16	0.10	1,955.34	1.03
510	Demand Defrost Electric	1.73	0.09	0.05	50.18	6.19	0.03	565.62	3.58
511	Anti-sweat (humidistat) controls	0.76	0.02	0.17	171.67	0.33	0.23	8,405.95	0.43
611	PC Manual Power Management Enabling	31.10	1.95	0.39	390.61	379.63	0.01	199.82	12.21
612	PC Network Power Management Enabling	61.18	3.85	0.78	781.22	734.82	0.01	203.12	12.01
621	Energy Star or Better Monitor	7.33	0.74	0.00	0.00	732,608.63	0.00	0.00	99,999.00
622	Monitor Power Management Enabling	29.21	1.84	0.40	395.82	330.59	0.01	215.55	11.32
631	Energy Star or Better Monitor	0.00	0.00	0.00	0.00	55.84	0.00	0.00	99,999.00
632	Monitor Power Management Enabling	0.05	0.00	0.02	20.83	0.02	0.41	6,544.61	0.37
641	Energy Star or Better Copier	1.44	0.15	0.00	0.00	144,309.69	0.00	0.00	99,999.00
642	Copier Power Management Enabling	6.09	0.38	0.32	323.79	17.22	0.05	845.68	2.82
651	Printer Power Management Enabling	24.81	1.56	0.66	655.29	118.34	0.03	420.87	4.77
801	Demand controlled circulating systems	6.37	0.14	0.13	125.13	46.55	0.02	887.38	7.30
803	High Efficiency Water Heater (electric)	2.32	0.05	0.10	103.34	13.41	0.04	2,013.43	5.78
804	Hot Water Pipe Insulation	0.99	0.02	0.02	24.27	5.76	0.02	1,103.38	5.80
805	Tankless Water Heater	1.70	0.04	0.02	24.94	16.49	0.01	661.39	9.67
911	Vending Misers (cooled machines only)	15.64	1.01	0.38	380.64	92.96	0.02	376.68	5.94

DSM ASSYST ADDITIVE SUPPLY ANALYSIS - Industrial Buildings									
Vintage E							Marginal	Marginal	Total
Batch 1		Cumulative	Cumulative	Cumulative	Cumulative	Cumulative	Energy	Capacity	Resource
Measure		GWH	MW	Energy	Capacity	Resource	Cost	Cost	Cost Test
Number	Measure	Savings	Savings	Cost	Cost	Cost Test	$/kWH	$/kW	TRC
101	Compressed Air-O&M	11.11	2.14	0.07	71.75	240.53	0.01	33.51	21.65
102	Compressed Air - Controls	2.11	0.41	0.04	40.73	15.31	0.02	100.08	7.25
103	Compressed Air - System Optimization	8.02	1.55	0.08	75.77	118.95	0.01	48.88	14.83
104	Compressed Air- Sizing	3.34	0.64	0.02	17.05	91.58	0.01	26.47	27.41
105	Comp Air - Replace 1-5 HP motor	0.14	0.03	0.02	15.19	0.18	0.11	562.80	1.29
106	Comp Air - ASD (1-5 hp)	0.14	0.00	0.03	25.10	0.08	0.18	8,090.97	0.59
107	Comp Air - Motor practices-1 (1-5 HP)	0.14	0.03	0.01	6.91	0.37	0.05	264.04	2.75
108	Comp Air - Replace 6-100 HP motor	0.46	0.09	0.06	62.06	0.47	0.14	703.79	1.03
109	Comp Air - ASD (6-100 hp)	1.28	0.03	0.01	8.79	19.94	0.01	309.34	15.57
110	Comp Air - Motor practices-1 (6-100 HP)	0.53	0.10	0.02	17.92	2.16	0.03	176.26	4.11
111	Comp Air - Replace 100+ HP motor	0.42	0.08	0.03	30.98	0.79	0.07	383.57	1.89
112	Comp Air - ASD (100+ hp)	1.79	0.04	0.05	52.21	6.59	0.03	1,293.19	3.67
113	Comp Air - Motor practices-1 (100+ HP)	0.54	0.10	0.02	19.23	2.13	0.04	183.79	3.94
114	Power recovery	0.00	0.00	0.00	0.00	0.00	0.05	133.94	3.46
115	Refinery Controls	0.00	0.00	0.00	0.00	0.00	0.02	63.47	7.30
116	Energy Star Transformers	0.11	0.02	0.00	2.79	0.64	0.02	128.57	5.64
201	Fans - O&M	1.31	0.23	0.01	7.02	33.60	0.01	31.06	25.55
202	Fans - Controls	12.20	2.09	0.32	324.36	62.56	0.03	154.87	5.13
203	Fans - System Optimization	3.70	0.35	0.13	126.58	13.08	0.03	366.36	3.54
204	Fans- Improve components	1.34	0.23	0.01	14.04	17.51	0.01	60.85	13.04
205	Fans - Replace 1-5 HP motor	0.25	0.04	0.02	22.52	0.39	0.09	515.87	1.54
206	Fans - ASD (1-5 hp)	0.25	0.01	0.04	37.21	0.18	0.15	7,401.48	0.72
207	Fans - Motor practices-1 (1-5 HP)	0.26	0.04	0.01	10.25	0.87	0.04	232.03	3.41
208	Fans - Replace 6-100 HP motor	0.62	0.14	0.09	91.99	0.60	0.15	647.27	0.97
209	Fans - ASD (6-100 hp)	0.52	0.04	0.01	13.03	2.00	0.03	322.00	3.88
210	Fans - Motor practices-1 (6-100 HP)	1.09	0.19	0.03	26.57	6.11	0.02	141.71	5.60
211	Fans - Replace 100+ HP motor	0.76	0.13	0.05	45.92	1.72	0.06	351.25	2.26
212	Fans - ASD (100+ hp)	2.17	0.06	0.08	77.39	6.28	0.04	1,198.99	2.89
213	Fans - Motor practices-1 (100+ HP)	0.40	0.16	0.03	28.51	1.00	0.07	173.80	2.46
214	#N/A	0.15	0.05	0.00	3.66	0.97	0.03	70.44	6.64
215	Power recovery	0.00	0.00	0.00	0.00	0.00	0.04	102.72	4.51
216	Refinery Controls	0.00	0.00	0.00	0.00	0.00	0.02	45.70	10.13
217	Energy Star Transformers	0.23	0.04	0.00	4.14	1.77	0.02	103.79	7.65
301	Pumps - O&M	8.85	1.58	0.04	44.90	240.32	0.01	28.33	27.14
302	Pumps - Controls	25.56	4.58	0.21	212.14	423.94	0.01	46.30	16.59
303	Pumps - System Optimization	21.88	3.91	0.45	445.16	147.95	0.02	113.82	6.76
304	Pumps - Sizing	2.72	1.16	0.09	89.79	14.72	0.03	77.26	5.40
305	Pumps - Replace 1-5 HP motor	0.33	0.06	0.04	36.01	0.41	0.11	611.12	1.26
306	Pumps - ASD (1-5 hp)	0.32	0.01	0.06	59.48	0.19	0.18	8,785.55	0.58
307	Pumps - Motor practices-1 (1-5 HP)	0.32	0.06	0.02	16.39	0.86	0.05	286.71	2.68
308	Pumps - Replace 6-100 HP motor	1.08	0.19	0.15	147.08	1.08	0.14	764.20	1.01
309	Pumps - ASD (6-100 hp)	3.50	0.07	0.02	20.84	62.58	0.01	287.75	17.90
310	Pumps - Motor practices-1 (6-100 HP)	1.23	0.22	0.04	42.47	4.92	0.03	191.68	4.00
311	Pumps - Replace 100+ HP motor	0.98	0.18	0.07	73.41	1.82	0.07	416.50	1.85
312	Pumps - ASD (100+ hp)	4.22	0.09	0.12	123.73	15.37	0.03	1,402.97	3.64
313	Pumps - Motor practices-1 (100+ HP)	1.27	0.23	0.05	45.58	4.86	0.04	199.86	3.84
314	Power recovery	0.00	0.00	0.00	0.00	0.00	0.05	135.06	3.43

DSM ASSYST ADDITIVE SUPPLY ANALYSIS - Industrial Buildings									
Vintage E							Marginal	Marginal	Total
Batch 1		Cumulative	Cumulative	Cumulative	Cumulative	Cumulative	Energy	Capacity	Resource
Measure		GWH	MW	Energy	Capacity	Resource	Cost	Cost	Cost Test
Number	Measure	Savings	Savings	Cost	Cost	Cost Test	$/kWH	$/kW	TRC
315	Refinery Controls	0.00	0.00	0.00	0.00	0.00	0.02	55.76	8.30
316	Energy Star Transformers	0.27	0.05	0.01	6.61	1.51	0.02	137.44	5.60
401	#N/A	0.23	0.05	0.00	1.19	6.34	0.01	22.78	27.89
402	#N/A	0.69	0.14	0.01	13.51	5.01	0.02	96.36	7.24
403	#N/A	0.21	0.02	0.00	1.42	3.94	0.01	62.12	18.40
404	#N/A	0.13	0.05	0.00	1.45	2.06	0.01	30.40	15.39
405	Drives - EE motor	0.94	0.24	0.02	18.21	7.28	0.02	77.33	7.73
406	Gap Forming papermachine	0.40	0.10	0.00	2.10	11.18	0.01	21.86	28.06
407	High Consistency forming	0.38	0.09	0.00	2.02	10.51	0.01	22.11	27.74
408	Optimization control PM	1.16	0.28	0.03	31.58	6.28	0.03	113.19	5.42
413	Clean Room - Controls	0.95	0.18	0.02	23.93	5.35	0.03	132.62	5.62
414	Clean Room - New Designs	0.76	0.14	0.03	28.90	2.75	0.04	201.38	3.65
415	Drives - Process Controls (batch + site)	3.40	0.43	0.16	160.47	10.26	0.05	372.01	3.02
416	Process Drives - ASD	0.14	0.03	0.00	4.86	0.54	0.04	186.64	3.94
417	O&M - Extruders/Injection Moulding	1.07	0.49	0.00	4.57	45.84	0.00	9.29	42.90
418	Extruders/injection Moulding-multipump	1.52	0.70	0.04	36.23	11.65	0.02	51.89	7.68
419	Direct drive Extruders	0.78	0.36	0.03	28.18	3.95	0.04	78.56	5.08
420	Injection Moulding - Impulse Cooling	0.55	0.25	0.02	15.85	3.52	0.03	62.46	6.38
421	Injection Moulding - Direct drive	0.48	0.22	0.02	22.14	1.92	0.05	99.94	3.99
422	Efficient grinding	0.28	0.06	0.02	19.16	0.59	0.07	311.44	2.10
423	Process control	0.06	0.01	0.00	0.61	0.78	0.01	48.36	13.53
424	Process optimization	0.04	0.01	0.00	1.15	0.18	0.03	138.68	4.72
425	Drives - Process Control	2.21	0.20	0.05	48.76	12.37	0.02	245.43	5.59
426	Efficient drives - rolling	2.66	0.24	0.04	44.74	19.51	0.02	187.22	7.32
427	Drives - Optimization process (M&T)	0.50	0.16	0.00	4.12	9.85	0.01	25.87	19.56
428	Drives - Scheduling	0.23	0.01	0.01	5.83	1.00	0.03	436.16	4.42
429	Machinery	0.30	0.08	0.01	5.62	2.48	0.02	66.95	8.24
430	Efficient Machinery	0.03	0.01	0.00	0.56	0.22	0.02	106.47	7.26
431	Energy Star Transformers	0.47	0.10	0.01	8.48	3.76	0.02	88.30	7.92
501	#N/A	1.12	0.05	0.01	8.14	16.87	0.01	158.90	15.13
502	#N/A	0.15	0.00	0.00	4.67	0.51	0.03	1,307.99	3.42
503	#N/A	0.05	0.00	0.00	2.23	0.11	0.05	676.57	2.38
504	Top-heating (glass)	0.03	0.00	0.00	0.44	0.28	0.01	295.14	8.45
505	Efficient electric melting	2.12	0.04	0.04	36.86	12.87	0.02	970.57	6.08
506	Intelligent extruder (DOE)	0.04	0.00	0.00	3.78	0.05	0.09	5,025.78	1.17
507	Near Net Shape Casting	0.58	0.01	0.00	3.83	9.22	0.01	369.71	15.96
508	Heating - Process Control	2.17	0.04	0.05	47.90	10.44	0.02	1,228.30	4.80
509	Efficient Curing ovens	1.26	0.06	0.03	31.80	5.59	0.03	491.15	4.42
510	Heating - Optimization process (M&T)	0.33	0.02	0.00	2.68	4.54	0.01	125.35	13.89
511	Heating - Scheduling	0.08	0.00	0.00	1.57	0.40	0.02	1,439.99	5.14
512	Energy Star Transformers	0.26	0.01	0.00	4.60	1.53	0.02	607.88	5.99
551	#N/A	0.70	0.13	0.00	4.08	15.38	0.01	31.91	22.09
552	#N/A	1.20	0.22	0.03	29.62	6.31	0.02	134.15	5.25
553	#N/A	0.04	0.01	0.00	0.77	0.31	0.02	97.94	7.20
601	Other Process Controls (batch + site)	0.60	0.11	0.02	18.67	2.69	0.03	163.91	4.48
602	Efficient desalter	0.00	0.00	0.00	0.00	0.00	0.02	54.48	8.50
603	New transformers welding	0.75	0.25	0.01	9.52	9.48	0.01	38.72	12.72
604	Efficient processes (welding, etc.)	0.90	0.17	0.01	11.46	9.80	0.01	67.50	10.92
605	Process control	0.00	0.00	0.00	0.11	0.02	0.03	159.27	4.85
606	Power recovery	0.00	0.00	0.00	0.00	0.00	0.04	101.37	4.57
607	Refinery Controls	0.00	0.00	0.00	0.00	0.00	0.02	44.77	10.34
608	Energy Star Transformers	0.05	0.01	0.00	0.91	0.38	0.02	87.24	7.74
701	Centrifugal Chiller, 0.51 kW/ton, 500 tons	2.75	2.34	0.06	61.02	31.22	0.02	26.07	11.35
702	Window Film - Chiller	0.74	0.63	0.05	48.60	2.81	0.07	77.60	3.81
703	EMS - Chiller	1.30	1.11	0.05	51.81	8.26	0.04	46.71	6.34
704	Cool Roof - Chiller	0.50	0.43	0.08	75.62	0.85	0.15	176.35	1.68
705	Chiller Tune Up/Diagnostics	0.18	0.18	0.01	6.56	1.32	0.04	37.16	7.55
706	Cooling Circ. Pumps - VSD	0.64	0.54	0.03	32.28	3.16	0.05	59.64	4.96
707	Energy Star Transformers	0.04	0.04	0.00	0.66	0.66	0.02	18.66	15.86
711	DX Tune Up/ Advanced Diagnostics	1.54	1.31	0.08	75.23	7.95	0.05	57.37	5.16
712	DX Packaged System, EER=10.9, 10 tons	2.38	2.02	0.03	33.64	42.31	0.01	16.63	17.80
713	Window Film - DX	1.04	0.88	0.03	32.61	8.34	0.03	36.87	8.03
714	Evaporative Pre-Cooler	0.87	0.74	0.13	128.77	1.47	0.15	174.42	1.70
715	Prog. Thermostat - DX	0.66	0.29	0.02	15.87	4.68	0.02	53.89	7.11
716	Cool Roof - DX	1.15	0.98	0.09	87.47	3.80	0.08	89.45	3.31
717	Energy Star Transformers	0.07	0.06	0.00	1.25	1.11	0.02	19.75	14.99
801	RET 2L4' Premium T8, 1EB	19.12	4.23	0.58	576.31	92.02	0.03	136.20	4.81
802	CFL Hardwired, Modular 36W	7.69	1.54	0.07	70.88	117.81	0.01	46.09	15.31
803	Metal Halide, 50W	0.69	0.13	0.14	142.68	0.48	0.21	1,083.49	0.69
804	Occupancy Sensor, 8L4' Fluorescent Fixtures	1.62	0.47	0.09	89.05	4.55	0.05	190.19	2.80
805	Energy Star Transformers	0.15	0.03	0.00	2.67	1.29	0.02	79.66	8.34
901	Replace V-belts	0.01	0.00	0.00	0.24	0.03	0.04	146.48	4.20
902	#N/A	0.01	0.00	0.00	0.34	0.09	0.02	115.34	6.05
903	Energy Star Transformers	0.08	0.02	0.00	1.37	0.65	0.02	77.57	8.31

Appendix C – JACO spreadsheets (1.5% scenario used)

2008-2010 REFRIGERATOR RECYCLING PROGRAM (RRP) SCENARIO ANALYSES				
Organization: National Grid - Rhode Island Electric				
QUANTIFICATION OF NET GHG IMPACTS OF 2008-2010 RRP				
Purpose: show magnitude of avoided CO2e emissions for each harvested unit, and for overall program				
GHG/CO2e Element	**1% Annual Harvest Rate (AHR)**	**1.5% Annual Harvest Rate (AHR)**	**2% Annual Harvest Rate (AHR)**	**Notes**
Avoided Electricity Generation Emissions				
CO2 emissions (lbs/kWh generated)	0.99	0.99	0.99	Value is for combined cycle/combustion turbine natural gas power plant. Value is based on avg natural gas generation plant in US as of 1999, adjusted by ratio of typical heat rates. In 1999, avg gas-fired power plant generated 1.32 lbs CO2/kwh of output (Table 1 from DOE 7/200 report at http://www.eia.doe.gov/cneaf/electricity/page/co2_report/co2report.html#electric); heat rates for typical gas-fired power plant and combined-cycle gas turbine are 10,000 and 7,500 btu/kWh, respectively (per http://www.nei.org/index.asp?catnum=2&catid=262)
Tons/Lb (k)	0.0005	0.0005	0.0005	constant (1 ton = 2000 lbs)
Net avoided annual tons CO2/unit	0.36	0.36	0.36	per above data; net annual kWh/unit is weighted value across refrigerators and freezers, and per scenario assumptions
Net avoided lifecycle tons CO2/unit (not discounted)	**2.87**	**2.87**	**2.87**	per above data; measure life value is per scenario assumptions
Net avoided lifecycle tons CO2 (3-year totals; not discounted)	**36,550**	**54,825**	**73,100**	per above data; total net [lifecycle] annual kWh is per scenario assumptions
CFC-11 Destruction Impacts				
Frac. Of RRP-Harvested Refrigerators and Freezers with CFC-11 foam (%)	81%	81%	81%	recent (2006 program year) typical experience for JACO (most program-specific data are not in public domain)
Foam Total Weight (lb/unit)	9.5	9.5	9.5	recent (2006 program year) typical experience for JACO (most program-specific data are not in public domain)
CFC-11 content of Foam (%)	10%	10%	10%	JACO estimate - typical harvested unit with CFC-11 foam
CFC-11 CO2e Global warming potentials (GWP; k)	4,680	4,680	4,680	US EPA, "Class I Ozone-Depleting Substances", per www.epa.gov/ozone/ods.html
Tons/Lb (k)	0.0005	0.0005	0.0005	constant (1 ton = 2000 lbs)
NTG (regarding CFC-11)	100%	100%	100%	JACO observation: CFC-11 destruction only occurs in presence of "sophisticated" appliance recycling programs (CFC-11 is usually simply ignored)
Per unit net avoided tons CO2e	**1.80**	**1.80**	**1.80**	per above data
Program net avoided tons CO2e (3-year totals; not discounted)	**22,946**	**34,419**	**45,892**	per above data; total program units is per scenario assumptions
CFC-12 Destruction Impacts				
Frac. Of RRP-Harvested Refrigerators and Freezers with CFC-12 refrigerant (%)	90%	90%	90%	recent (2006 program year) typical experience for JACO (most program-specific data are not in public domain)
CFC-12 harvested (lbs/unit)	0.4	0.4	0.4	recent (2006 program year) typical experience for JACO (most program-specific data are not in public domain)
CFC-12 CO2e Global warming potentials (GWP; k)	10,720	10,720	10,720	US EPA, "Class I Ozone-Depleting Substances", per www.epa.gov/ozone/ods.html
Tons/Lb (k)	0.0005	0.0005	0.0005	constant (1 ton = 2000 lbs)
NTG (regarding CFC-12)	100%	100%	100%	JACO observation: CFC-12 destruction only occurs in presence of "sophisticated" appliance recycling programs (CFC-12 is usually recycled rather than destroyed)
Per unit net avoided tons CO2e	**1.93**	**1.93**	**1.93**	per above data
Program net avoided tons CO2e (3-year totals; not discounted)	**24,590**	**36,885**	**49,179**	per above data; total program units is per scenario assumptions
Total GHG Impacts				
Per unit net avoided tons CO2 & CO2e/unit (not discounted)	**6.60**	**6.60**	**6.60**	per above data; reference point: a typical avg passenger car/light-duty truck driven in the U.S. produces 6.16 tons (5.59 metric tons) of CO2 equiv. annually, per http://www.usctcgateway.net/tool/resources/cars_trucks.html
Program net avoided tons CO2 and CO2e (3-year totals; not discounted)	**84,086**	**126,129**	**168,172**	per above data

Rhode Island Energy Efficiency and Resources Management Council (EERMC):

Opportunity Report – Phase I

Submitted on July 15, 2008 to:

the RI Public Utilities Commission, the General Assembly, the RI Office of Energy Resources, and National Grid

Attachment II:

The Potential for Cost-Effective Combined Heat and Power in Rhode Island

By NESCAUM with Pace Energy

NESCAUM
www.nescaum.org

The Clean Air Association of the Northeast States
101 Merrimac Street, 10th Floor Boston, MA 02114
Phone 617-259-2000 Fax 617-742-9162
Arthur N. Marin, Executive Director

Opportunity Report to the Energy Efficiency & Resources Management Council:

Submitted on July 15, 2008 – Phase I

The Potential for Cost-Effective Combined Heat and Power in Rhode Island

BACKGROUND

In 2006, the Rhode Island legislature approved the ground-breaking "Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006.[1]" The Comprehensive Energy Bill was designed to systematically maximize ratepayers' economic savings by placing a requirement on the distribution utility to procure all energy efficiency that is less costly than supply. Combined heat and power (CHP) is a proven energy technology that, in addition to providing clear opportunities for reducing greenhouse gases and other air pollutants, is also an economically attractive option for Rhode Island. The 2006 Act explicitly identifies distributed generation under system reliability resources to be procured by the distribution "including, but not limited to…thermally leading combined heat and power systems."[2] In addition, the Least Cost Procurement and System Reliability Standards proposed by the Council and finalized by the RI PUC define CHP as an Alternative Resource Technologies (ART) that the electric and gas efficiency programs should target, as long as CHP applications are "…cost-effective, deliver net reductions in energy consumption, and provide environmental benefits."[3]

In addition, the deployment of cost-effective CHP can also help Rhode Island in meeting its ambitious goals for cost-effective clean energy and climate change reductions, including the greenhouse gas (GHG) reduction goals set out in the 2001 Climate Action Plan of the New England Governors/Eastern Canadian Premiers.[4] CHP could bring significant reductions in energy use and CO_2 emissions that will need to occur in the power generation, commercial, and industrial sectors. Rhode Island's commercial and industrial sectors, ideal settings for CHP applications, are responsible for significant portions of the state's GHG footprint. In 2003, these sectors combined contributed over 20 percent of the state's total GHG emissions.[5]

This analysis is designed to inform and be a part of Phase 1 of the Energy Efficiency Resource Management Council's (EERMC) Opportunity Report that identifies opportunities to procure

[1] *Comprehensive Energy Conservation, Efficiency & Affordability Act of 2006.*
[2] *Section 39-1-27.7 of the Comprehensive Energy Conservation, Efficiency & Affordability Act of 2006*
[3] Rhode Island Energy Efficiency and Resource Management Council, *Draft Proposed Standards for Energy Efficiency and Conservation Procurement and System Reliability*, February 29, 2008.
[4] Conference of the New England Governors/Eastern Canadian Premiers Conference, August 2001. *Climate Change Action Plan of 2001*, prepared by the Committee on the Environment and the Northeast International Committee on Energy of the Conference of New England Governors and Eastern Canadian Premiers (Boston, MA/Halifax, NS). The plan is accessible at: http://www.negc.org/documents/NEG-ECP%20CCAP.PDF
[5] Based on NESCAUM calculations using data derived from US EPA's *State Inventory Tool (SIT).* For more information on the tool, see: http://www.epa.gov/climatechange/wycd/stateandlocalgov/analyticaltools.html

efficiency, distributed generation, demand response, and renewables. The Opportunity Report will in turn guide the distribution utility, National Grid, in developing an Energy Efficiency Procurement Plan and System Reliability Procurement Plan for submission to the Rhode Island Public Utility Commission by September 1, 2008.

The primary purpose of this analysis is to generate an estimate of the technical and economic potential for CHP resources in Rhode Island, and to evaluate the economic, environmental, and system reliability benefits of associated with that potential. In developing these estimates, NESCAUM and Pace Energy have conferred with a variety of key energy and utility experts, relevant Rhode Island state agencies, and industry leaders in Rhode Island. We also provide sensitivities of these estimates to key variables and to potential policy incentives, and using our best expert judgment, we suggest a reasonable target for achievable CHP in Rhode Island based on the analysis.

METHODOLOGY AND DATA

Technical Potential for CHP

Technical potential for CHP is defined as the technological feasibility of CHP, based on consumption characteristics for electricity and thermal energy at a given facility type. Technical potential is an estimate that accounts for CHP's feasibility on an engineering basis only. Non-technical factors such as interest in CHP, availability of natural gas, ease of integrating CHP with existing systems, and system or facility economics are not considered.

No recent bottom-up engineering studies of the technical potential for CHP specific to Rhode Island exist. So to derive an estimate of the technical potential for CHP in Rhode Island, we relied primarily on a recent study of the technical potential for CHP in Massachusetts. A 2005 white paper by the University of Massachusetts-Amherst (UMass) showed that the technical potential for CHP systems in Massachusetts is approximately 4,700 MW for new CHP units at over 18,000 sites in the commercial and industrial sectors.[6] Technical potential for CHP in Massachusetts was estimated using energy consumption data collected at the state level by the U.S. Department of Energy's (DOE) *Energy Information Administration (EIA)*.

Based on input from industry and utility experts in Rhode Island and regional CHP experts, we assumed that the commercial and industrial sectors in Rhode Island were similar in composition to those in Massachusetts (MA) and that a ratio applied to the MA estimate based on relative energy consumption between the corresponding sectors in the two states would be a reasonable

[6]Mattison, Lauren, May 2006. "*Technical Analysis of the Potential for Combined Heat and Power in Massachusetts*," University of Massachusetts Amherst, Department of Mechanical and Industrial Engineering, Center for Energy Efficiency and Renewable Energy.

approximation of the technical potential in Rhode Island, given the lack of primary research for Rhode Island. So, we downscaled the Massachusetts estimate to Rhode Island using RI's relative energy consumption levels as a percentage of MA energy consumption in 2005. Using these percentages of 16.7 percent and 7.6 percent for relative energy consumption in the commercial/institutional and industrial sectors, respectively, we estimate that the technical potential for CHP in Rhode Island to be 654MW in the commercial/institutional sector and 59 MW in the industrial sector, respectively, for a total of 713 MW in CHP technical potential.

The estimate of technical potential plays a critically important role in this analysis, because it is used as a constraint on the economic potential for CHP in the modeling methodology. In other words, economic potential cannot exceed the technical potential for CHP because CHP is not physically achievable in certain building types, no matter how attractive economic parameters may be.

According to a few RI industry experts, our estimate above of technical potential of 714MW may be an overstatement of the technical potential for CHP in Rhode Islands, so we assume this to a high-end estimate of technical potential to bound the analysis of economic CHP potential.[7] For a low-end estimate of CHP technical potential, we use the only published estimate of technical CHP potential that is specific to Rhode Island, from a 2000 US DOE on CHP potential in the US. [8] The DOE study finds that technical for CHP in Rhode Island's commercial and institutional sectors may be as low as 289 MW. This estimate was based on 1995 EIA data, so assuming relatively steady growth over time in the size of this sector since the mid-1990s, we estimate that 350MW is a reasonable lower bound for CHP technical potential. Through the remainder of the analysis, we use 350MW as a low-end estimate and 714MW as high-end estimate of the technical potential for CHP.

Obviously, this is a relatively wide range of uncertainty for CHP technical potential. In the absence of a recent detailed, bottom-up assessment of the technical potential for CHP in Rhode Island that evaluates CHP opportunities at the building level, however, technical potential will continue to be a source of significant uncertainty in evaluating the economic potential for CHP.

In the next sections, we describe our methodology for modeling economic and achievable potential for CHP in RI.

Economic Potential for CHP

Economic potential for CHP is defined as a subset of technical potential that represents CHP opportunities whose economic benefits outweigh costs (i.e., benefit-cost ratio of 1.0 or greater).

[7] Personal communication with John Farley, TECH-RI, June 20, 2008.

[8] US Department of Energy, Energy Information Administration. "The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector," prepared for US DOE by ONSITE SYCOM Energy Corporation (Washington, DC), January 2000.

Because Rhode Island's least-cost procurement legislation is designed to identify energy efficiency, renewable energy, and CHP resources whose costs are less than that of traditional generation resources, the evaluation of economic potential considers total costs and benefits of CHP, regardless of which entities may incur those costs and benefits. In the context of this analysis, economic potential does not address considerations that are specific to individual potential customers for CHP, such as a preferred payback period for investment in a CHP system. This analysis only evaluates the opportunity for economically viable CHP at the sectoral level (i.e., for the entire commercial sector), rather than from the more disaggregated viewpoint of individual customers.

Economic potential also does not account for various non-economic factors that affect CHP's actual penetration into the market, such as the fact that some potential CHP customers may not have the staff expertise to operate a system, may not have credit worthiness to consider investment, or are simply unaware of the opportunity to use CHP in their building. These factors influence the achievable potential for CHP, which will be addressed later in this report.

NE-MARKAL Energy Model

To evaluate the economic potential for CHP in Rhode Island, we applied the NE-MARKAL energy model to the commercial and industrial sectors in Rhode Island. Owing to the MARKAL model's strong basis in least-cost optimization and technological detail, NE-MARKAL is well-suited to assess the economic potential for CHP in Rhode Island in the context of least-cost procurement planning.

Based on the MARKAL family of energy models, NE-MARKAL is a least-cost linear optimization model of the Northeast's energy system which includes detailed representations of power generation and the end use transportation, commercial, industrial, and residential sectors.[9] The model is based on a large database including detailed engineering and economic descriptions of energy technologies, currently available fuel sources, alternative fuels available in the future and the end-use demand for different forms of energy in each sector. Based on this detailed representation of the region's energy infrastructure, NE-MARKAL calculates the least-cost combination of energy technologies and fuel sources that meet the demand for energy in each end-use sector.[10] For example, to meet demand for thermal energy in the commercial and industrial sectors, the model evaluates the costs and capabilities of CHP in comparison to other technologies capable of meeting those same thermal energy needs, such as boilers and furnaces. NE-MARKAL optimizes the costs of the entire energy system (i.e., all energy demand for all sectors) over the model's entire time horizon on a net present value basis.

[9]States included in the NE-MARKAL modeling framework include the six New England states, New York, New Jersey, Pennsylvania, Delaware, Maryland, and the District of Columbia. Documentation on the MARKAL family of models can be found at: http://www.etsap.org/MrklDoc-I_StdMARKAL.pdf. NESCAUM can make available detailed documentation for the NE-MARKAL model upon request.
[10]Energy demand by sector is endogenous to the NE-MARKAL model, and are derived from state energy data in the US DOE Energy Information Administration's *Annual Energy Outlook* (AEO).

As a linear programming model, NE-MARKAL conducts this least-cost optimization subject to whatever constraints or parameters are provided by the user. For example, we impose constraints on the modeling system to represent federal limits on criteria pollutants as well as regional limits on GHG emissions under the Regional Greenhouse Gas Initiative (RGGI).

We use a single-state Rhode Island version of the regional NE-MARKAL model to conduct this analysis. The model's detailed characterizations of CHP technologies (i.e., costs, technical parameters) were refined for an earlier analysis of economic potential in Massachusetts and carried over to this analysis of CHP potential for Rhode Island.

Reference Case

In order to develop an estimate of the potential for CHP in Rhode Island assuming all cost-effective CHP resources are deployed, we first estimate the baseline, or reference case, for CHP in Rhode Island, that is, the deployment of CHP that would occur in the absence of a least-cost procurement approach. To do so, we rely on a 2006 estimate of existing CHP systems in Rhode Island from the Energy and Environment Analysis, Inc. (EEA) CHP state database. EEA's database estimates over 103 MW of existing CHP resources in the state.[11] This estimate was subsequently updated and modified by UMass researchers to reflect recent changes to 102.5 MW. **Table 1** below provides a description of individual CHP installations in Rhode Island as of 2006.

Table 1
Existing CHP Systems in Rhode Island, 2006

Organization/Developer Name	Facility Name	City	Capacity, kW
Pawtucket Power Associates, Inc.	Colfax, Inc.	Pawtucket	67,000
Rhode Island Hospital	Rhode Island Hospital	Providence	10,400
Ridgewood Power LFG	Ridgewood Power LFG	Johnston	6,400
State Of Rhode Island	Central Power Plant	Cranston	4,700
Ridgewood Pwr Mgmt Corp	The Worcester Company	Centerdale	4,260
Noresco	Rhode Island Howard	Kingston	3,500
Brown University	Brown University Central Heating Plant	Providence	3,200
Bradford Dyeing Associates Inc.	Bradford Dyeing Associates Inc.	Bradford	2,000
Amity Associates	25 Lincoln Center Blvd. - Office Bldg	Lincoln	960
Alliant Energy	Landmark Medical Center-Fogarty Unit	North Smithfield	60
Micro Cogenic Systems, Inc.	Cartie Nursing Home	Central Falls	22
Micro Cogenic Systems, Inc.	Orchard View Manor	East Providence	22
Micro Cogenic Systems, Inc.	Shalom Apartments	Warwick	22
Total Installed CHP in Rhode Island, 2006			**102,546**

Source: Energy & Environment Analysis (EEA) state CHP database (2006), modified by UMass.

[11] EEA's estimate of existing RI CHP resources in their CHP database is available at: http://www.eea-inc.com/chpdata/States/RI.html.

To project a reference case of actual market penetration for CHP from 2006 forward, we assume that the rate of penetration of new CHP systems in Rhode Island is similar to the rate of new CHP installations in Massachusetts over the last decade. Based on information in EEA's 2006 state CHP database, NESCAUM found that the rate of CHP penetration in Massachusetts was approximately 2.7 percent per year over the period 1996 to 2006. Applying this rate of penetration to Rhode Island, we generate a reference case of for CHP market penetration in Rhode Island of a cumulative 141 MW between 2006 and 2018, or an average of 3.2 MW of additional CHP per year.

Timeframe

The timeframe for this analysis is 2008 to 2018. The NE-MARKAL model evaluates the energy system periodically on three-year intervals, so we provide results over the full timeframe of 2008 to 2020.

Key Assumptions for Economic Potential

Below, we describe the key variables and assumptions used for the analysis of RI economic potential for CHP incremental to the reference case. Key variables and assumptions that are most influential in determining results include: CHP system costs and technical characteristics; natural gas prices; emissions factors for key pollutants; and, environmental requirements.

- **CHP System Characteristics**

Because NE-MARKAL is a bottom-up model driven by engineering costs, the assumptions characterizing specific energy technologies are a critical driver of the model's least-cost optimization calculations. **Table 2** below provides our assumptions about key technical parameters for CHP systems, including capacities, system efficiencies, heat rates, and availability factors for different CHP technologies.[12] Installed costs on a per kW basis are also represented, expressed in 2000 dollars. Note that these cost estimates are for the installed costs of equipment only, and do not include program costs or other costs incurred to develop and implement CHP projects.

[12]Regional CHP experts note that there are no commercially available microturbines in the 350kW capacity range—more typically, 75kW units are combined in sets of two or three to accommodate capacity needs in this range. We will continue to refine these assumptions for installed costs of CHP based on recent empirical data describing commercially available technologies.

Table 2
CHP System Costs and Technical Parameters

	Capacity (kw)	Heat Rate (BTU/kWh)	Total System Efficiency	Availability	Power-to-Heat Ratio	Installed Cost 2000 $s/kw
Recip Engine #1	100	4,063	74.6%	90%	0.60	$1,623
Recip Engine #2	5,000	4,914	67.4%	90%	1.11	$1,049
Microturbine #1	30	5,509	66.7%	90%	0.47	$2,624
Microturbine #2	350	4,668	70.2%	90%	0.60	$1,447
Gas Turbine #1	5,000	5,947	64.7%	90%	0.64	$1,139
Gas Turbine #2	25,000	5,164	67.4%	90%	0.89	$989
Steam Turbine #1	3,000	4,568	72.3%	90%	0.10	$514
Fuel Cell #1	200	4,860	63.7%	90%	0.95	$5,108

Source(s): US EPA CHP Partnership database (2006); NESCAUM analysis.

Table 3 below shows assumed emissions factors on a per MWh basis for both CO_2 and nitrogen oxides (NOx), by type of CHP technology.[13] These assumptions will drive the emissions results associated with economically viable CHP. Emissions factors for CO_2 and NOx were derived by NESCAUM using US EPA guidance for output-based emissions limits for CHP systems.[14]

Table 3
CHP Emission Factors, by Technology

	Capacity (kw)	Lbs CO_2/MWh	Lbs NOx/MWh
Recip Engine #1	100	535.0	44.30
Recip Engine #2	5,000	592.7	1.48
Microturbine #1	30	598.3	0.54
Microturbine #2	350	568.6	0.53
Gas Turbine #1	5,000	617.3	1.16
Gas Turbine #2	25,000	592.5	0.92
Steam Turbine #1	3,000	552.2	0.20
Fuel Cell #1	200	626.3	0.06

Source: NESCAUM calculations based on US EPA guidelines for output-based emissions standards (2007).

- **Natural Gas Prices**

Virtually all new CHP systems in Rhode Island will be natural gas-fired, so natural gas prices will be one of the most influential factors determining economic potential for CHP in Rhode

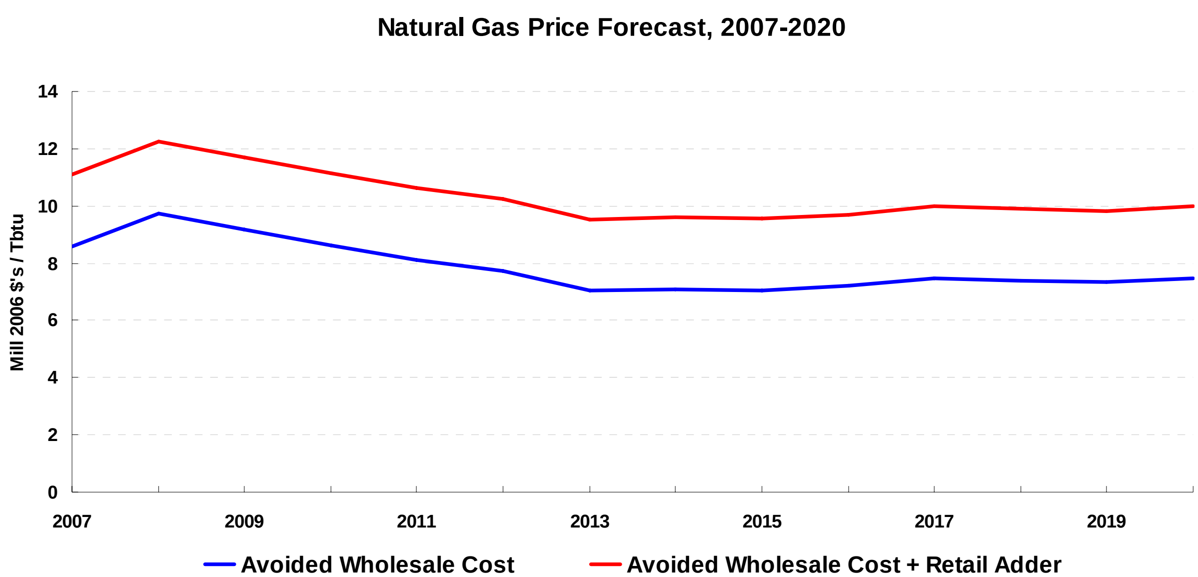
[13]Because virtually all new CHP systems in Rhode Island are likely to use natural gas, and natural gas has low emissions for other pollutants such as particulate matter and volatile organic carbons, we do not provide emissions factors for these other pollutants.

[14] NESCAUM calculations, based on output-based emissions factors for natural gas CHP systems provided by Tom Frankiewicz, Program Manager, US EPA CHP Partnership, June 2007.

Island. **Graph 1** below shows avoided wholesale natural gas costs, based on a 2007 analysis by Synapse Energy Economics of avoided energy supply costs, as well as the price of wholesale costs plus a "retail adder" to reflect retail gas costs to end-users in the commercial, industrial, and residential sectors.[15] The differential between wholesale and retail prices averages about 20 percent over the given timeframe.

Based on input from utility representatives and other industry experts, the majority of new CHP opportunities in Rhode Island will be for relatively small systems, most well under 1MW in capacity. As such, the commercial, institutional and small industrial sectors are likely to face retail prices rather than wholesale gas costs for the majority of potential new CHP installations, so we run the model using retail gas prices. However, we conduct a sensitivity run using the avoided wholesale gas costs as well.

Graph 1



Sources: Synapse Energy Economics, 2007; National Grid, 2008.

- **Environmental Requirements**

As described in the description of NE-MARKAL, the model optimizes for a least-cost solution to meet energy needs, subject to any other constraints on the energy system specified by the user. As such, we apply constraints within the NE-MARKAL model to represent environmental and energy regulations. These requirements include existing regulations as well as new regulations and/or requirements that will be applicable in the foreseeable future.

[15] Synapse Energy Economics, August 2007. "Avoided Energy Supply Costs in New England: Final Report," prepared for Avoided Energy Supply Component (AESC) Study Group, (Cambridge, MA).

In terms of emissions limits on criteria pollutants, NOx and carbon monoxide (CO) are the key pollutants of concern with respect to CHP systems. In May 2007, Rhode Island passed *Regulation No. 43*, which streamlines permitting requirements for smaller distributed generation and applies output-based emissions standards to reward CHP's overall efficiency in meeting both thermal and electrical energy demands.[16] We have applied *Regulation No. 43* limits for NOx emissions within NE-MARKAL by creating a constraint representing these emissions limits and applying it to CHP technologies.[17]

Each state participating in the Regional Greenhouse Gas Initiative (RGGI) program to limit CO_2 emissions from large power plants (i.e., larger than 25MW) has an assigned emissions budget which delineates its portion of the overall regional cap on CO_2 emissions. **Table 4** below shows Rhode Island's CO_2 emissions budget under RGGI, which we have built into NE-MARKAL as a constraint on the power generation sector. Note that RGGI does not actually take effect until January 2009—over the period 2009 to 2012, emissions are capped at 2006 levels. Over the period 2012 to 2018, CO_2 emissions are required to decline by 10 percent below 2006 levels.[18]

Table 4
Rhode Island CO_2 Emissions Budget under RGGI

	2008	2011	2014	2017	2020
Rhode Island CO_2 Budget (thousand metric tons of CO2)	2,412	2,412	2,392	2,231	2,171

Finally, we also apply a constraint to simulate requirements associated with Rhode Island's Renewable Portfolio Standard (RPS), which requires 16 percent of in-state generation to come from renewable energy resources by 2020.[19]

Achievable Potential

Achievable potential refers to the subset of economic potential that considers the influence of individual customer preferences as well as other, non-economic factors. Currently these non-

[16]In other words, a CHP system that meets Rhode Island's basic requirements for system efficiency (55%) and power-to-heat ratios can receive a compliance credit against its actual emissions based on the emissions that would have been created by a conventional separate system used to generate the same thermal output. The complete text of Regulation No. 43 can be accessed at: http://www.dem.ri.gov/pubs/regs/regs/air/air43_07.pdf

[17]Because we do not have CO emissions factors for the majority of combustion technologies included in NE-MARKAL, we do not apply the CO limits to CHP for this analysis.

[18]Although RGGI's requirements extend only to 2018, this table shows a continuation of the cap until 2020. Because NE-MARKAL operates in 3-year increments, we modeled RGGI until 2020 in order to show its impact on CHP potential through the study period of 2018.

[19] Rhode Island's RPS requirements allow for generation from numerous renewable resources (photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, anaerobic digestion, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels) and are accessible at: http://www.rilin.state.ri.us/Statutes/TITLE39/39-26/INDEX.HTM

economic factors are cited as a key barrier to new CHP installations, not just in Rhode Island but elsewhere in New England as well. For example, a key barrier noted by an academic expert who has consulted with individual customers in Rhode Island is that many of these potential customers are discouraged from implementing CHP simply for lack of personnel qualified to operate these systems.[20] In other cases, it is customer preferences that limit the adoption of CHP, even for highly efficient systems. While non-profit institutions such as hospitals and universities can justify relatively longer "payback periods" (e.g.,2 to 5 years) for investments in new energy technologies, some private sector entities have payback requirements of less than one year, due to internal competition for funds from other capital projects.

Currently in Rhode Island, actual market penetration of CHP is low, probably close to an average of 2 to 3 MW per year. Additional policies and measures are needed to influence customer preferences and convert economic potential into achievable CHP. To examine the potential for bringing more economically viable CHP into actual deployment, we examine the impact of two observable, quantifiable measures that are amenable to the NE-MARKAL modeling framework. The measures that we model to examine achievable CHP potential include:

(1) Elimination of utility charges for stand-by power in the event of CHP system failure; and

(2) Introduction of revenues from the Forward Capacity Market (FCM), the market for electric capacity resources in the New England power pool.

Both of these measures are modeled by imputing a corresponding change in system cost for CHP technologies. In the case of back-up charges, we eliminate the back-up charge entirely to represent a change to achievable potential. **Table 5** below shows the back-up charge schedule for CHP systems of different sizes, eliminated under our sensitivity runs.

Table 5
Utility Back-Up Charges for CHP

	Rate B-62	Rate B-32
Customer Service Charge ($s)	$11,118.72	$236.43
Back up charge 2008 ($s per kw)	$2.24	$5.12
Back up charge 2009 ($s per kw)	$2.22	$5.11
Supplemental charge 2008 ($s per kw)	$2.24	$2.00
Supplemental charge 2009 ($s per kw)	$2.22	$1.99

Source: National Grid, 2008.

Forward capacity revenues are represented as negative costs to CHP systems based on their capacity. **Table 6** shows the schedule of estimated FCM revenues over the time period in the analysis.

[20] Personal communication with Dr. Vin Rose, Professor of Engineering, University of Rhode Island, July 3, 2008.

Table 6
Estimated Revenues for the Forward Capacity Market[21]

	2008	2011	2014	2017	2020
FCM Payment ($s/kw/year)	$45.0	$49.4	$54.0	$59.0	$64.5

Source(s): ISO New England, 2007 and National Grid, 2008.

These are just examples used for modeling purposes of measures targeted at achievable potential—other policy changes such as net metering or other program efforts, such as additional customer outreach and education, while less quantifiable within our modeling framework, are nonetheless very viable strategies and could be equally or even more effective than the two measures which we have modeled in this analysis.

RESULTS

The section below provides the results of our modeling and analysis of CHP's economic and achievable potential, respectively, in Rhode Island from 2008 to 2018. Key results for economic potential include: total capacity of CHP; shifts in electricity generation and consumption by the commercial/institutional sector and overall; changes in fuel consumption (natural gas, oil, and electricity) by the commercial/institutional sector and overall; and, changes in emissions of key pollutants (CO_2 and NOx). For achievable CHP under the two policy scenarios we explore, we provide total capacity as well as emissions results.

Note that these results to be dominated by the commercial/institutional sector—because the industrial sector in Rhode Island is relatively small and represents less than 10 percent of the total technical potential (i.e., 59 of 714 MW on the high end), the majority of economic potential and associated changes are driven by the commercial/institutional sector.

Finally, it is important to again note how important an influence on economic potential is played by the assumption of CHP technical potential, because technical potential acts as a constraint on economic potential. For the shorter timeframe of 2011, we provide only estimates corresponding with the high-end technical potential for CHP. Over the longer timeframe of 2020, we provide graphics below corresponding with our high-end estimate of technical potential for CHP (i.e., 714MW), but also provide figures and commentary corresponding with the application of the low-end estimate of technical potential (i.e., 350MW) as a constraint on economic potential.

[21] Based on input from National Grid, we adjusted ISO New England's estimates of FCM revenues downward in the latter part of the timeframe.

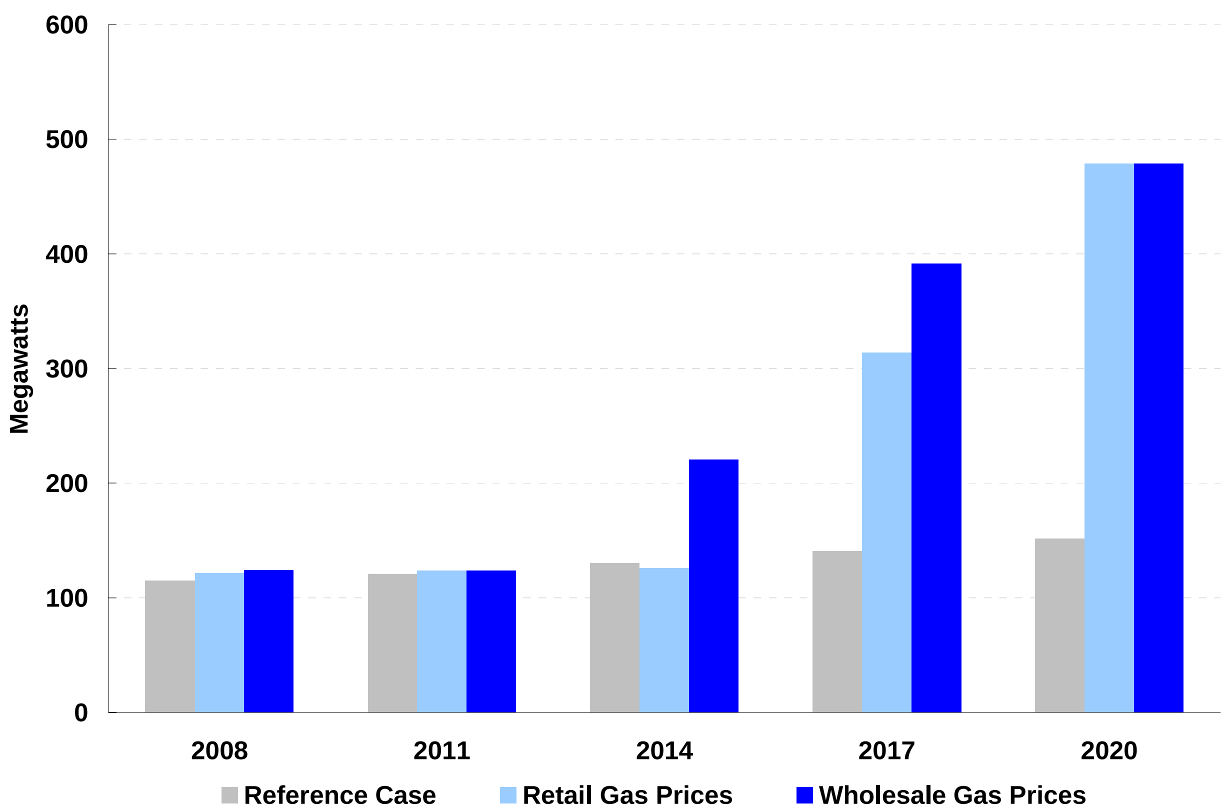
Economic Potential

- **CHP Capacity**

Graph 2 below shows that, under the high-end technical potential scenario, the capacity of CHP increases significantly over the reference case when considering all cost-effective CHP opportunities in the commercial/institutional sector. By then end of the timeframe, under the high-end technical potential, incremental CHP capacity is nearly 480 MW in total, or 330 MW above the reference case penetration of 150 MW.

In addition, the trajectory of new CHP capacity additions is more aggressive under the wholesale gas price scenario than under the higher retail rate scenario. This is because the differential between these two natural gas price scenarios—about 20 percent—makes a meaningful difference to overall CHP economics because of the role of gas costs in overall CHP operating expenses. Under the lower wholesale price¸ substantially more CHP is economically viable.

Graph 2
Economic Potential for CHP Capacity in Rhode Island

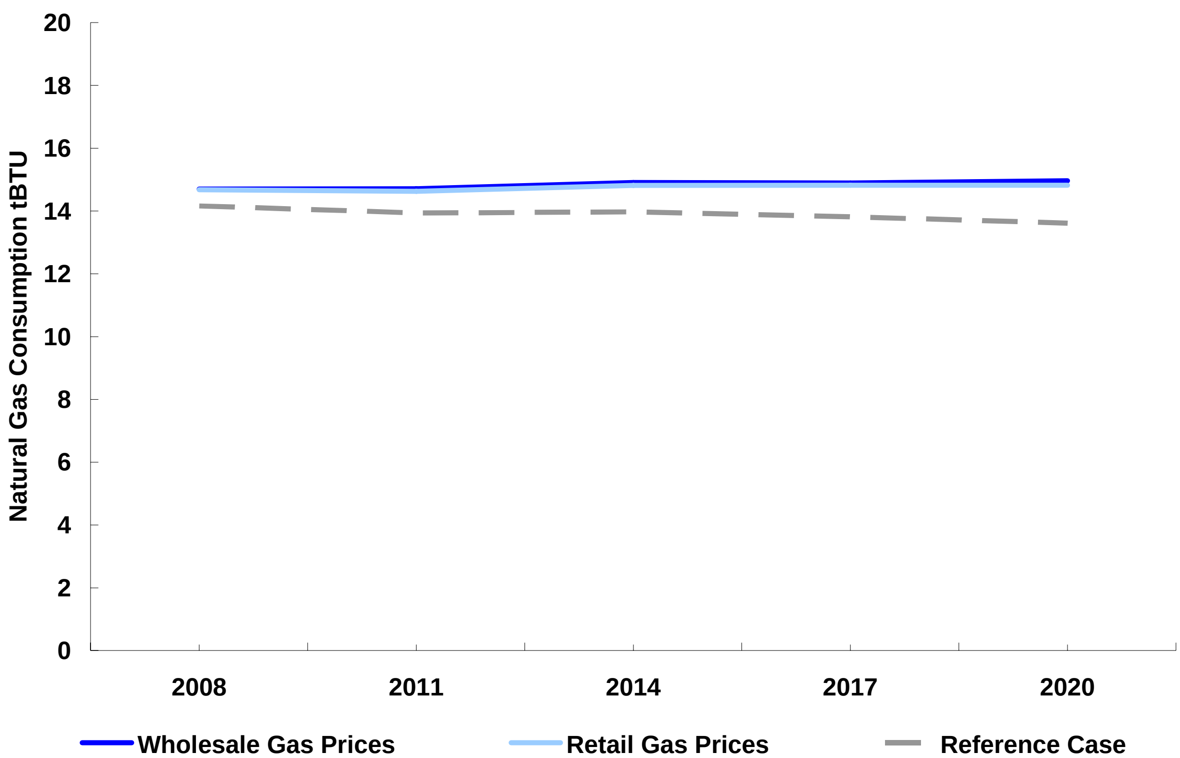


In comparison to the high-end technical potential, under the low-end technical potential where total capacity is limited to 350MW, new CHP capacity tops out at 350MW by the end of the timeframe, or just under 200 MW of incremental potential above the reference case. In other words, economic potential for new CHP is approximately 130MW less under the low-end technical potential than under the high-end technical potential scenario.

- **Natural Gas Consumption**

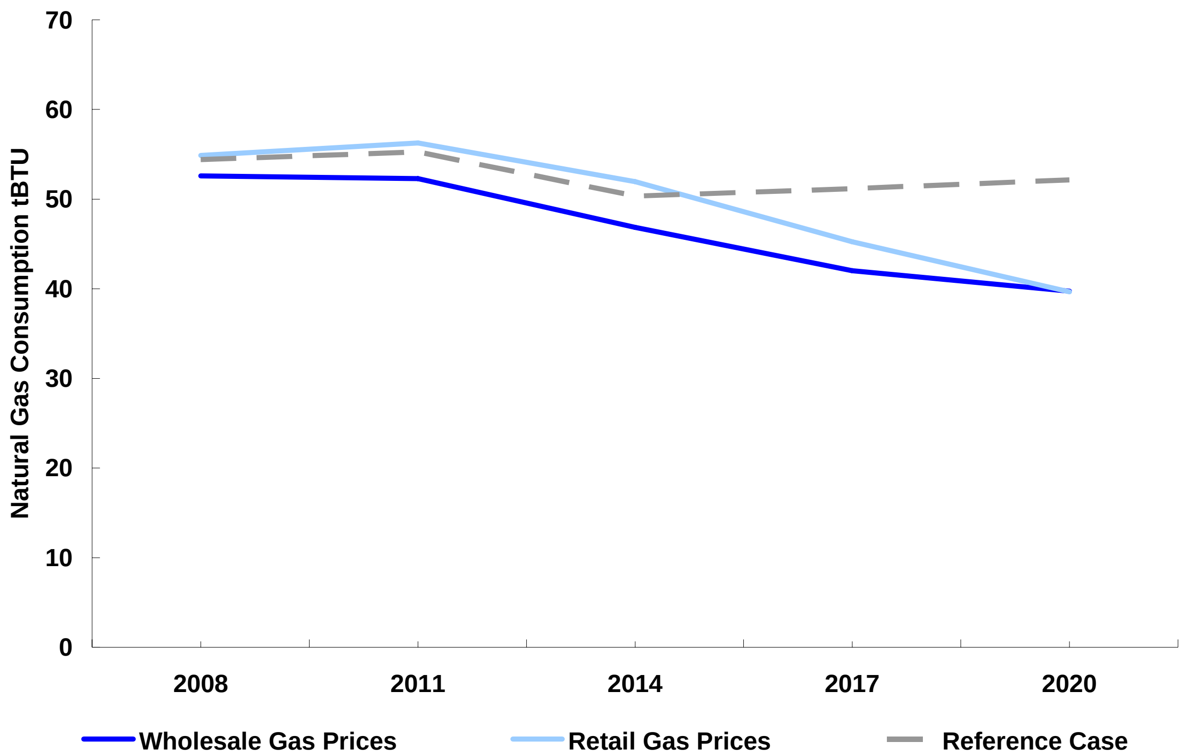
Graph 3 shows natural gas consumption associated with the incremental CHP capacity of 360MW under the high-end technical potential. Under both natural gas price scenarios (wholesale and retail), natural gas consumption in the commercial/institutional sectors increases by approximately 10 percent above the reference case, as the new CHP capacity causes a shift away from oil use by some thermal applications (e.g., boilers) and toward gas.

Graph 3
Commercial/Institutional Natural Gas Consumption



Although natural gas use increases somewhat in the commercial/institutional sector to accommodate the increase in gas-fired CHP capacity, **Graph 4** below shows that, over the entire timeframe, total natural gas consumption decreases from roughly 52 tBTU under the reference case, to 40 tBTU under the high-end technical potential scenario. This reduction results from a shift away from natural gas use by the power generation sector and to a lesser degree, by other thermal technologies in the commercial/institutional sector, to more efficient electricity and thermal energy production by new, gas-fired CHP systems.

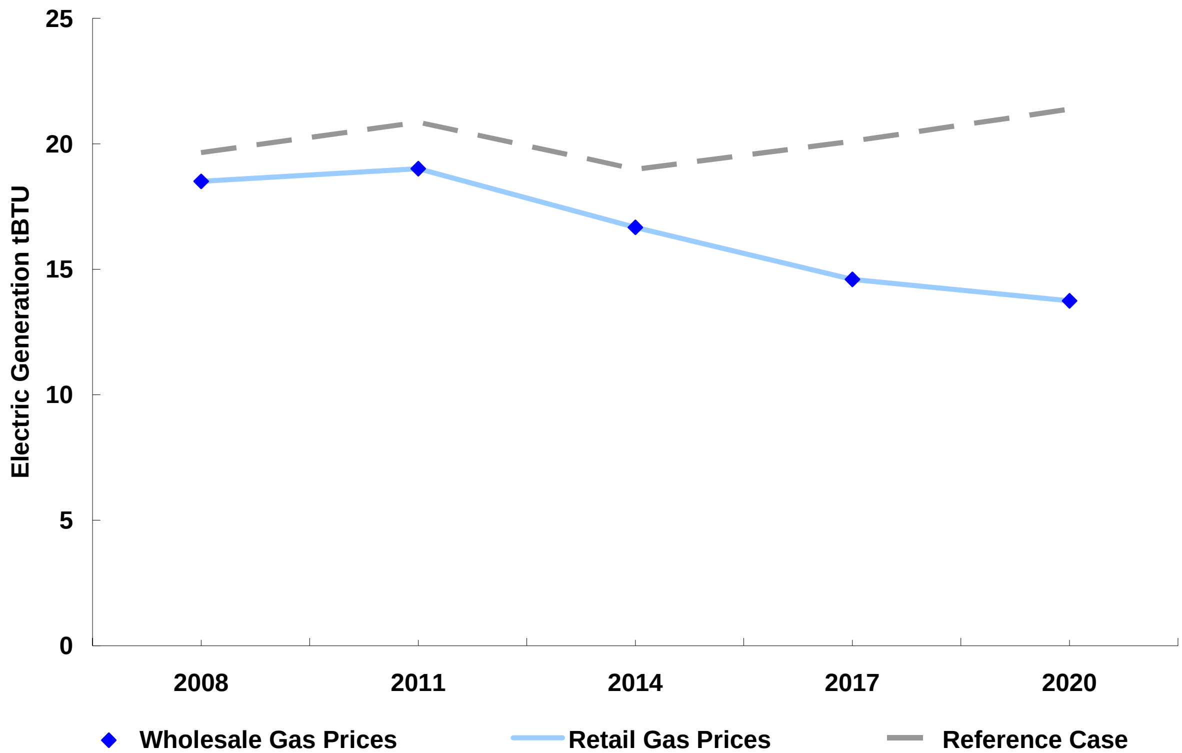
Graph 4
Total Natural Gas Consumption



- **Electricity Generation**

In accordance with a shift away from natural gas use by the power generation sector as new CHP capacity comes on-line, electricity generation by the power sector falls. As shown in **Graph 5**, under the high-end technical potential scenario, by the end of the timeframe, electricity generation by the power sector has decreased to about 14 tBTU, or a decline of nearly 20 percent relative to the reference case electricity use of 21 tBTU.

Graph 5
Power Sector Electricity Generation

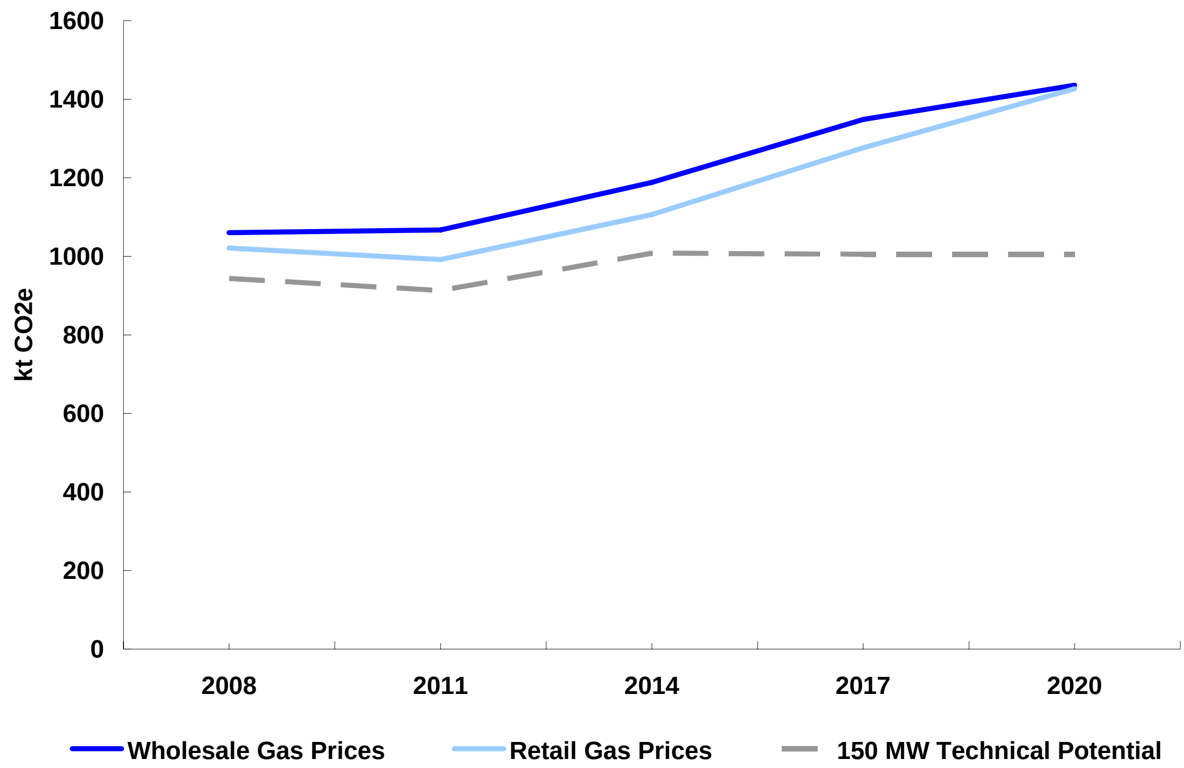


- **CO_2 Emissions**

In the commercial/institutional sector, CO_2 emissions under the high-end technical potential case increase over emissions in the reference case, at first gradually and then more aggressively after 2014, as more CHP capacity comes on-line. **Graph 6** shows that by 2018, CO_2 emissions in the commercial sector (1,427 kilotons of CO_2-equivalent) are 40 percent higher than in the reference case (1,000 kilotons of CO_2-equivalent).

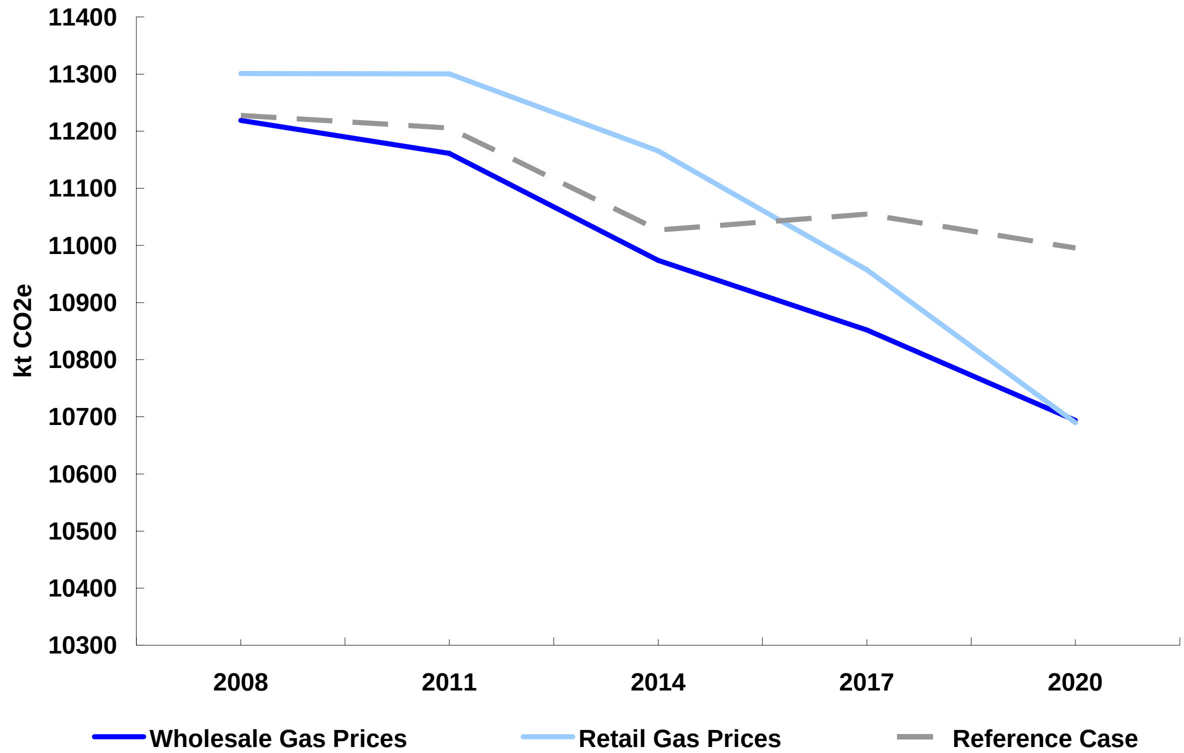
Under the low-end technical potential scenario, where total CHP capacity is constrained at 350MW, we see a similar outcome of a reduction in overall CO_2 emissions (10,515 kilotons of CO_2-equivalent) relative to the reference case. However, CO_2 emissions in the commercial sector do not increase above the reference case in this instance, because the increase in CHP capacity is not so significant relative to the reference case that gas use and emissions

Graph 6
Commercial/Institutional CO_2 Emissions in Rhode Island



Despite an increase in CO_2 emissions in the commercial/institutional sector, however, **Graph 7** shows total CO_2 emissions decline in comparison to the reference case, from 10,996 kilotons of CO_2-equivalent to 10,690 kilotons of CO_2-equivalent. This is because the increase in commercial/institutional sector emissions is counterbalanced by an even larger decrease in CO_2 emissions in the power sector, as overall electricity generation falls with the shift in generation capacity to CHP. Since electricity generation on average is more carbon-intensive than generation from newer, cleaner CHP, this shift results in a decrease in emissions.

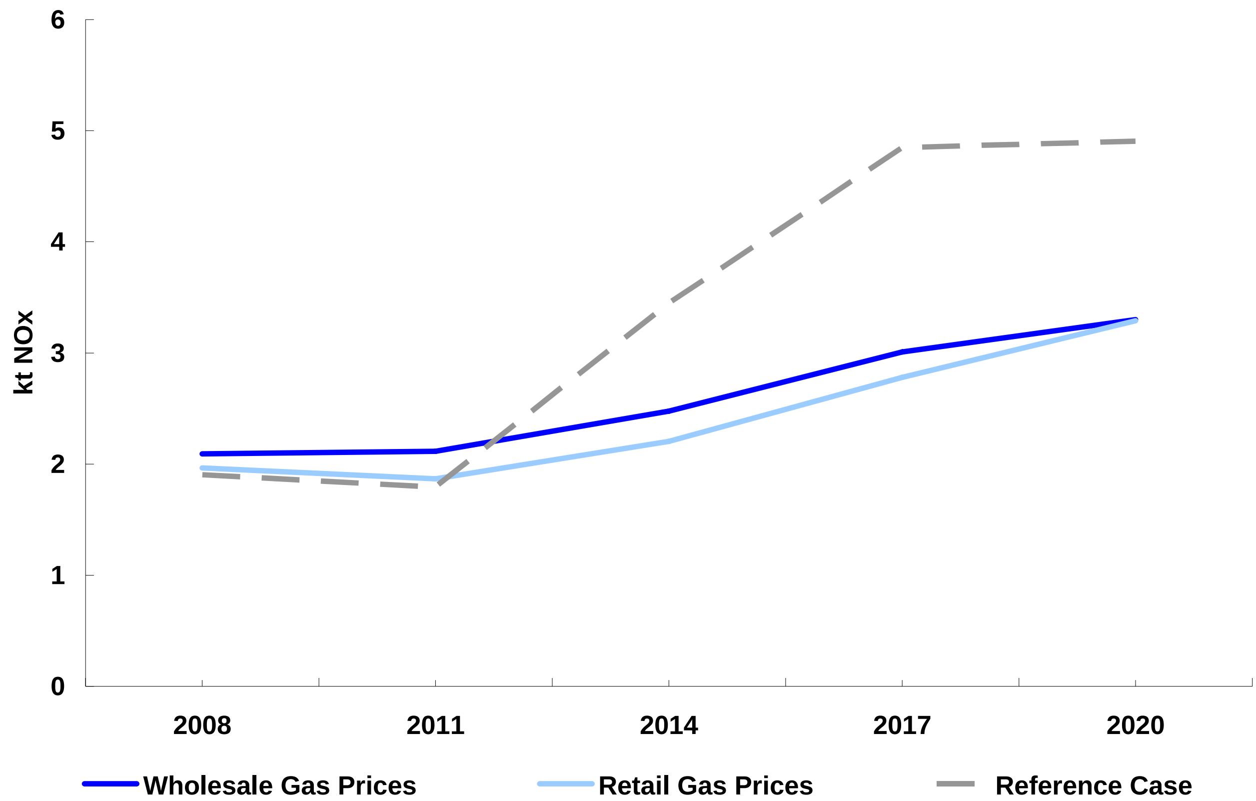
Graph 7
Total CO2 Emissions in Rhode Island



o NOx Emissions

Under the high-end technical potential scenario, NOx emissions in the commercial/institutional sector decline in a similar fashion to CO_2 emissions, relative to the reference case. As displayed by **Graph 8**, by the end of the timeframe, NOx emissions have decreased from almost 5.0 kilotons of NOx under the reference case to 3.3 kilotons. This reduction results from a shift away from relatively more NOx-intensive technologies in the electricity generation sector combined with cleaner CHP displacing some more NOx-intensive thermal technologies.

Graph 8
Commercial Sector NOx Emissions



Achievable Potential

Because the two policy measures we have introduced to the analysis—eliminating CHP stand-by charges and introducing FCM revenues—both change the basic economics of CHP by reducing operating expenses (or increasing operating revenue), not surprisingly, these measures enhance the degree to which CHP is deployed as a economically viable strategy for the commercial/institutional sectors.

As **Graph 9** shows, under the high-end technical potential scenario, significantly more CHP is deployed as a result of both policy measures. Even in 2008, capacity of economic CHP is more than double that of the reference case capacity of 108MW under the no stand-by rate scenario, and over 400MW with the introduction of FCM revenues. By the end of the timeframe, both measures result in a cumulative CHP capacity more than three times that of the reference case, and runs well over half to the total high-end technical potential of 714MW.

Overall, the addition of FCM revenues has a greater impact on total CHP capacity than elimination of the stand-by charges, possibly because the elimination of the stand-by charge is more preferential to smaller capacity CHP systems, whereas the FCM revenue stream is equally beneficial to CHP systems of any capacity.

Graph 9
Economic Potential for CHP Capacity in Rhode Island

KEY FINDINGS AND NEXT STEPS

This analysis finds that CHP is a cost-effective resource for meeting electric and thermal energy needs in Rhode Island, particularly in the commercial/institutional sector. Under low-end and high-end assumptions of the technical potential for CHP, the estimates of potential capacity for economic CHP (i.e., where benefits exceed costs) are 200MW and 330MW, respectively, above the estimated reference case CHP penetration level by 2020.

Deployment of new CHP capacity in RI would likely result in an increase in natural gas use, CO_2 and NOx emissions in the commercial/institutional sector; however, total natural gas use and emissions of both CO_2 and NOx would decline as electricity generation by centralized power plants and the use of less efficient thermal technologies in the commercial/institutional sector decrease with the shift toward CHP.

The potential for economic CHP was evaluated under two price scenarios for natural gas—wholesale and retail gas rates. Over the relevant timeframe, the difference of approximately twenty percent between wholesale and retail gas rates does not result in significant cumulative differences in CHP capacity, natural gas use, or emissions. Note again, however, that this analysis considers the economic opportunity for the commercial/institutional sector in the aggregate, rather than from the perspective of individual CHP customers. Such a significant difference in the cost of an essential CHP operational variable like natural gas would indeed have a major influence on the evaluation of individual project economics.

In the event of a Phase II of the EERMC's evaluation of the opportunity for cost-effective CHP in Rhode Island, there are a number of refinements to this analysis that would enhance the understanding of the magnitude and nature of the potential opportunity presented by CHP resources. Refinements that we would consider to be high priority for additional effort include the following:

- **Generate a bottom-up RI-specific estimate of technical potential for CHP**: The assumption of technical potential is a key determinant of economic potential for CHP. Both the low- and high-end estimates of CHP technical potential used in this analysis were derived from studies in other contexts (i.e., Massachusetts, US) and scaled accordingly to Rhode Island. A bottom-up study of technical potential based on recent, Rhode Island-specific energy use and building data could substantially reduce the uncertainty range for economic potential of CHP.

- **Estimate near-term CHP opportunity:** Preliminary results suggest that if economic potential for CHP is optimized over a shorter timeframe, such as 2008-2011, it would be economic to invest in additional CHP immediately, rather than delaying investment in CHP in the latter part of the 2008-2020 timeframe when optimizing costs over the long-term. These initial results require additional verification, but they suggest that the availability of cost-effective CHP resources over the next three to five years is not insignificant.

- **Conduct quantitative evaluation of benefits:** With additional effort and information, we would provide a quantitative valuation of the suite of benefits of greater deployment of CHP, including the value of avoided electricity generation, avoided CO_2 and NOx emissions, more efficient use of natural gas, and system reliability benefits that could be realized if CHP is targeted toward areas of current or potential future transmission constraints.

- **Further investigate factors influencing achievable CHP potential:** Current annual rates of CHP penetration in Rhode Island are relatively low (i.e., less than 5MW per year, based on averaging of recent historical data), significantly lower than estimated economic potential even under the low-end assumption of technical potential. In order to drive achievable potential in RI to levels approximating economic potential for CHP, additional efforts such as policy changes, consumer outreach and education, and regulatory reform could be beneficial. While we have explored in this analysis the influence of measures that directly affect CHP system costs, including stand-by charges and the introduction of revenues from capacity markets, we would collect empirical information, such as a phone survey of potential CHP customers, to better understand current barriers to CHP implementation and design effective measures for increasing achievable potential in Rhode Island.

Rhode Island Energy Efficiency and Resources Management Council (EERMC):

Opportunity Report – Phase I

Submitted on July 15, 2008 to:

the RI Public Utilities Commission, the General Assembly, the RI Office of Energy Resources, and National Grid

Attachment III:

Building Capacity for Non-Utility Scale Renewable Energy in Rhode Island

By the University of Rhode Island Partnership for Energy

Building Capacity for Non-Utility Scale Renewable Energy in Rhode Island

Submitted to the
Energy Efficiency and Resource
Management Council

By the University of Rhode Island
Partnership for Energy

July 14, 2008

TABLE OF CONTENTS

ACRONYMS & ABBREVIATIONS

AWEA	American Wind Energy Association
BTU	British thermal unit
CBA	Cost-benefit analysis
CEA	Cost-effectiveness analysis
CEC	California Energy Commission
cfs	Cubic feet per second
DEM	Department of Environmental Management
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
GHP	Geothermal heat pump
GSHP	Ground-source heat pump
GW	gigawatt
GWh	gigawatt hour
HAWT	Horizontal axis wind turbine
HGHP	Hybrid geothermal heat pump
HGSHP	Hybrid ground-source heat pump
INEL	Idaho National Environmental and Engineering Laboratory
J	joule
kg	kilogram
kJ	kilojoule
km	kilometer
kW	kilowatt, equal to 1,000 W
kWh	kilowatt-hour
kWh/year	kilowatt-hour per year
LORI	Large On-Site Renewables Initiative
m	meter

m/s	meters per second
MJ	megajoule, equal to 1,000,000 J
mph	miles per hour
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
NPV	Net present value
O&M	operation and maintenance
OER	Office of Energy Resources
PV	photovoltaic
REC	Renewable energy credit
RIDEM	Rhode Island Department of Environmental Management
s	second
SBER	Struever Bros. Eccles & Rouse
SRI	Small Renewables Initiative
TDP	Technology Demonstration Program
URIPE	University of Rhode Island Partnership for Energy
USDOE	United States Department of Energy
VAWT	Vertical axis wind turbine
W	watt
W/m^2	Watts per square meter
Wh	watt-hour

KEYWORDS

GENERAL

Base load: The amount of electrical power needed at all times and during all seasons.

British Thermal Unit (BTU): A unit of energy defined as the amount of energy necessary to heat one pound of water one degree Fahrenheit. Depending on how it is calculated, it is equal to 1054-1060 J. For reference, 1 Wh is equal to approximately 3.41 BTU.

Capital cost: The cost of development, construction and the equipment required for operations and including, for industry, the cost of field development. The total cost needed to bring a project to an operable status.

Cost-benefit analysis: A technique used to compare the various costs associated with an investment with the benefits that it proposes to return.

Cost-Effective: A criterion that specifies that a technology or measure delivers a good or service, at equal or lower cost than current practice. Returning a benefit that justifies the initial investment.

Demand-side management: The process of managing the consumption of electrical energy, generally to minimize demand and costs.

Distributed generation: Any electricity generating technology, installed by a customer or independent electricity producer, which is connected at the distribution system level of the electric grid.

Efficiency: The ratio of output vs. input, of energy or power, expressed as a percentage.

Energy: The ability to do work; the quantity of electricity delivered over a period of time. The electrical energy term commonly used is kilowatt hours (kWh), which represents the power (kW) operating over some period of time (hours); 1 kWh = 3600 kilojoules.

Generator: Converts the kinetic energy from a source into electrical energy (electricity).

Grid: A utility term for the network of wires that distributes electricity from a variety of sources across a large area.

Incentive: A formal scheme used to promote or encourage specific actions or behavior by a specific audience during a defined period of time. In this context an incentive is one that encourages and supports the use of renewables.

Joule (J): The International System of Units (SI) of energy defined as 1 $kg \cdot m^2/s^2$. Also equal to the energy produced by a power of one watt flowing for one second ($1W \cdot s$).

Kilowatt-hour (kWh): A unit of energy equal to 3,600 kJ. A standard unit of energy used in the commercial energy field. The energy equal to generation or usage of 1kW for 1 hour.

Load shifting: The practice of altering the pattern of energy use so that on-peak energy use is shifted to off-peak periods. Load shifting is a fundamental demand-side management objective.

Load: The collective measure of power consumption of appliances and other devices connected to a power source, at a point in time.

Megawatt (MW): A measurement of power equal to 1 million watts.

Mill: A monetary unit equal to one one thosandth (1/1000) of a dollar, in other words one tenth (1/10) of one cent.

Net-metering: A form of buy-back agreement. Grid electric power is either consumed by a house, or if the house's own generation exceeds its needs, electricity flows into the grid. At the end of a payment period, when the meter is read, the system owner pays the utility the difference between what the house has consumed and what was supplied to the grid.

Non-utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for electric generation and is not an electric utility. Non-utility power producers include qualifying co-generators, qualifying small power producers, and other non-utility generators (including independent power producers).

Normalize: a means of leveling a value so that its effect may be better measured such as: costs, prices, revenue, power, and energy (i.e. $/kW and $/kWh).

Off-grid: Not connected to power lines; electrical self-sufficiency.

On-site renewable energy: Provides a building - or group of buildings - with all or part of its electricity, heating or cooling from renewable energy sources that are located within the boundaries of its site

Peak load: The maximum power requirement of a system during a given time, or the amount of power required to supply customers at times when need is greatest. The term can refer either to the load at a given moment (e.g. a specific time of day) or to averaged load over a given period of time (e.g. a specific day or hour of the day).

Power: The rate of doing work. The rate at which work is performed or energy is transmitted, or the amount of energy required or expended for a given unit of time. Measured in watts (= joules/second).

Tax credit: A specified amount by which a taxpayer's taxes will be reduced in return for some behavior.

Therm: A unit of heat energy, equal to 100,000 BTU. Approximately 29.3 kWh.

Watt (W): The International System of Units (SI) unit of electrical power, defined as 1 $kg \cdot m^2/s^3$. A rate of doing work at one joule per second (1 W = 1 J/s). Commonly used to define the rate of electricity consumption of an electric appliance.

Watt-hour (Wh): A unit of energy equal to 3,600 J. Literally, it is the energy equal to generation or usage of 1 W for 1 hour. Similar to the kilowatt-hour, 1,000 Wh = 1 kWh.

GEOTHERMAL

Desuper heater: Device that takes waste heat extracted by heat pumps or air conditioners and uses it to heat domestic hot water.

Geothermal Heat Pumps (GHP): Also known as ground source heat pumps (GSHP). A heating and/or cooling system that operates based on the stability of underground temperatures by using the available heat in the winter and puts heat back into the ground in the summer.

Hybrid GHP: Capable of producing forced air heat and hot water simultaneously and individually.

Ton: In refrigeration, the ton is used as a unit of cooling. It is defined as 12,000 BTU/h. As a reference, it is approximately equal to 3.52 kW.

HYDROELECTRICITY

Cofferdam: A temporary enclosure beneath the water that allows water to be displaced by air to create a dry work environment for activities such as dam work.

Dam: A blockage of a watercourse that allows the water level of the river to rise and create falling water which produces energy. It also permits to control the flow of water.

Head: The vertical distance through which the water travels.

Flow: The amount of water that moves through the system. More water falling through the turbine will produce more power. Power is therefore also directly proportional to river flow.

Flow rate: The amount of water flowing per second measured in cubic feet per second (cfs).

High hazard dam: Dam failure or misuse will result in a probable loss of human life.

Hydropower: Capturing and converting energy from flowing water.

Penstock: A pipe to convey the water from the intake to the powerhouse.

Regulator: An electrical controlor to automatically maintain a constant voltage level of the energy produced by the generator, and reroutes excess energy into the home, the power grid, or storage batteries.

Run-of-the-river: The instantaneous natural water flow that passes through the powerhouse that produces electricity; the flows that occur in the stream at the intake and flows downstream of the powerhouse are virtually identical to pre-development flows.

Significant hazard dams: A dam where failure or misuse results in no probable loss of human life but can cause major economic loss, disruption of lifeline facilities or impact other concerns detrimental to the public's health, safety or welfare. Examples of major economic loss include washout of a state or federal highway, washout of two or more municipal roads, loss of vehicular access to residences, (e.g. a dead end road whereby emergency personnel could no longer access residences beyond the washout area) or damage to a few structures.

Small-scale hydropower: A hydropower generation capacity of up to 10MW; in the U.S. 'small' scale means <30 MW. (There is no international consensus on the definition of small hydropower)

Turbine: A piece of equipment with blades on a shaft within a housing structure that spin due to water pressure of moving water. The force of falling water pushing against the turbine's blades causes the turbine to spin. The turbine converts the kinetic energy of falling water into mechanical energy.

SOLAR

Photovoltaic (PV) cells: Conversion of solar radiation (the sun's rays) to electricity by the effect of photons (tiny packets of light) on the electrons in a solar cell. Cells usually made of specially-treated silicon.

Solar irradiance: The amount of solar energy that arrives at a specific area at a specific time.

Solar panel: A group of photovoltaic cells make up a solar panel that can be installed onto a flat surface.

Solar thermal: Heat (rather than electricity) that is generated by the sun. Examples would be solar swimming pool heaters and household domestic water heaters.

WIND

Anemometer: Instrument used to measure wind speed, usually measured either from the rotation of wind-driven cups or from wind pressure through a tube pointed into the wind

Cut-in speed: The wind speed at which the turbine starts to generate usable power or the wind speed at which it begins to produce power. If the turbine's cut-in speed is significantly below a site's average wind speed, problems are inevitable.

Cut-out speed: The speed at which the turbine hits the limit of its alternator and can no longer put out increased power output with further increases in wind speed. The wind speed at which the turbine may be shut down to protect the rotor and machinery from damage.

Guy wires: A tensioned cable designed to add stability to the tower.

Inverter: An appliance used to convert independent DC power into standard household AC current.

Platform: Ground conditions and soil parameters

Rotor: The noticeably spinning part of the turbine that includes the hub and blades which rotate around an axis.

Siting: The act of locating a proposed turbine on a parcel.

Torque: The force required to turn a shaft multiplied by the radius at which the force is applied.

Turbine: A machine that captures the energy of the wind and transfers the motion to an electric generator shaft.

Weibull distribution: A statistical distribution that is widely used for matching field data.

Wind power class: A way of quantifying on a scale the strength of the wind at a project site. The Department of Energy's National Renewable Energy Laboratory defines the wind class at a site on a scale from 1 to 7 (1 being low and 7 being high) based on average wind speed and power density to offer guidance to potential developers as to where wind projects might be feasible.

Wind power densities: Wind power density, measured in watts per square meter, is a useful way to evaluate how much energy is available at a potential site for conversion by a wind turbine.

1 INTRODUCTION

1.1 Purpose

This report has two purposes. First, it is part of a larger submission by the Energy Efficiency and Resources Management Council to the RI Public Utilities Commission to comply with the requirements for Systems Reliability and Least Cost Procurement, which are established by section 39-1-27.7 of the Rhode Island General Laws. Second, it is intended to be useful as a freestanding public document describing the challenges and the opportunities for renewable energy deployment by households, businesses, and institutions in Rhode Island which wish to use the energy generated for primarily their own purposes. Utility-scale renewable energy projects by comparison supply electricity to the grid for use by other consumers.

1.2 Major Findings and Recommendations

This report has two basic findings: First that non-utility scale renewable energy projects can contribute, at a very modest level at this time, to meeting statutory requirements for systems reliability procurement, and second that a vibrant market for supplying non-utility scale renewable energy systems is underdeveloped in Rhode Island.

The report recommends that capacities and conditions be developed that are conducive to non-utility scale renewable energy adoption and implementation. The report also recommends that targeted, specific programs be established as part of, or in conjunction with reliability and least cost procurement. The goal of these programs would be to reduce capital cost burdens of non-utility renewable energy installations to a level that makes certain projects economically feasible and/or acceptable while still realizing a net benefit to the overall system, consistent with requirements for cost effectiveness, reliability, prudence and environmental responsibility. The findings and recommendations are discussed in greater depth in chapter 2 of this report.

1.3 Organization of the Report

This report has seven chapters and five appendices. The first chapter is this introduction, which presents major findings, key concepts, and Rhode Island conditions.

The second chapter provides an integrated assessment of findings and recommends actions that should be taken to achieve the potential contribution of non-utility scale renewable energy for Rhode Island.

The third through seventh chapters discuss non-utility scale renewable energy by energy sources, with primary attention given to wind, solar, hydro and geothermal; each is given its own chapter. Biomass, fuel cells and tidal power have not been addressed because they have been given less public/consumer attention as means meeting electricity needs in the state or because their promise is longer term. Each of these four chapters is designed to be freestanding to facilitate their use within minimal need to refer other sections of this report.

The appendices provide methods, tables summarizing incentives for non-utility scale renewable energy development in Rhode Island and nearby states, describe the analytical methods used, and cite references.

1.4 Preparation of the Report

This report was developed and written by the University of Rhode Island Partnership for Energy. The University recognizes that energy is a critical public policy issue and that addressing energy issues constructively and effectively is critical to the well being of the people of the State. The URI Partnership for Energy involves four colleges and provides a formal structure for coordinating and integrating the complex array of research, outreach and educational issues in which one involved in responding to the energy challenges faced by Rhode Island.

This report is the work of a team of students: Taylor Asher (Ocean Engineering), Corrie Haley (Environmental Economics and Management), Amanda Meisner (Environmental Science and Management), Hannah Morini (Environmental Economics and Management), and Rachel Sholly (Environmental Science and Management), and faculty advisors: Dr. Marion Gold, Dr. Brett Lucht, and Dr. Kenneth Payne. Dr. Payne was the principal advisor. Dr. Gold provided the study enthusiastic leadership and a good home in the Outreach Center, which she directs. The work would not have been possible without the support of Dr. Jeffrey Seemann, Dean of the College of Environment and Life Sciences, who championed the establishment of the University of the Rhode Island Partnership for Energy and who secured faculty capacity to undertake this study; Dr. Peter Alfonso Vice President for Research and Economic Development, who committed the University to developing a capacity to provide timely neutral analytics on energy issues and who executed the memorandum of understanding with the state Office of Energy Resources which facilitated undertaking this project; and Dr. Robert Carothers, President of the University, who in an extraordinarily difficult budget year, gave consistent and critical support to building the University's capacity to address energy issues, such as those examined in this report.

1.5 Key Concepts

Three concepts provide the underpinning of this report:

(1) Renewable Energy is defined by section 39-26-5 of the RI General Laws as:

(a) Direct solar radiation;

(b) The wind;

(c) Movement or the latent heat of the ocean;

(d) The heat of the earth;

(e) Small hydro facilities;

(f) Biomass facilities using eligible biomass fuels and maintaining compliance with current air permits; eligible biomass fuels may be co-fired with fossil fuels, provided that only the renewable energy fraction of production from multi-fuel facilities shall be considered eligible;

(g) Fuel cells using the renewable resources referenced above.

(2) Non-Utility Scale means electrical generating capacity that is installed and operated primarily to meet the electrical needs of the owner or user of the capacity rather than

capacity that is installed and operated for the purpose of supplying electricity to the grid; electricity from non-utility scale projects that is in excess of the needs of the owner or user may, however, be supplied to the grid.

(3) Systems Reliability Procurement is a process of meeting electrical needs in Rhode Island, including from renewable energy resources, in a manner that is optimally cost-effective, with measurable, net system benefits that have the qualities of being reliable, prudent and environmentally responsible. The related concept of Least Cost Procurement is a process of obtaining capacity needed in the electrical system through efficiency, conservation and other alternative sources, when doing so is lower cost than electrical energy from traditional generation.

1.6 Rhode Island Conditions

An opportunity is a conjunction of conditions and circumstances that make possible and are favorable to an outcome or an action. Opportunity can be thought of as "conditions favorable to an outcome." Conditions exist at a time and in a place. This part of the Introduction reviews current conditions in Rhode Island that have a bearing on opportunities for non-utility scale renewable energy.

1.6.1 Resource Conditions

Renewable energy resources are not evenly distributed within the United States. Some regions and locations in the country have greater renewable energy potential than others. With regard to non-utility scale renewable energy, Rhode Island is, overall, poorly situated: potential is present, but it is not great in comparison with other places.

With regard to solar energy potential, Rhode Island is in a more northern latitude and at a low average elevation (Figure 1.1).

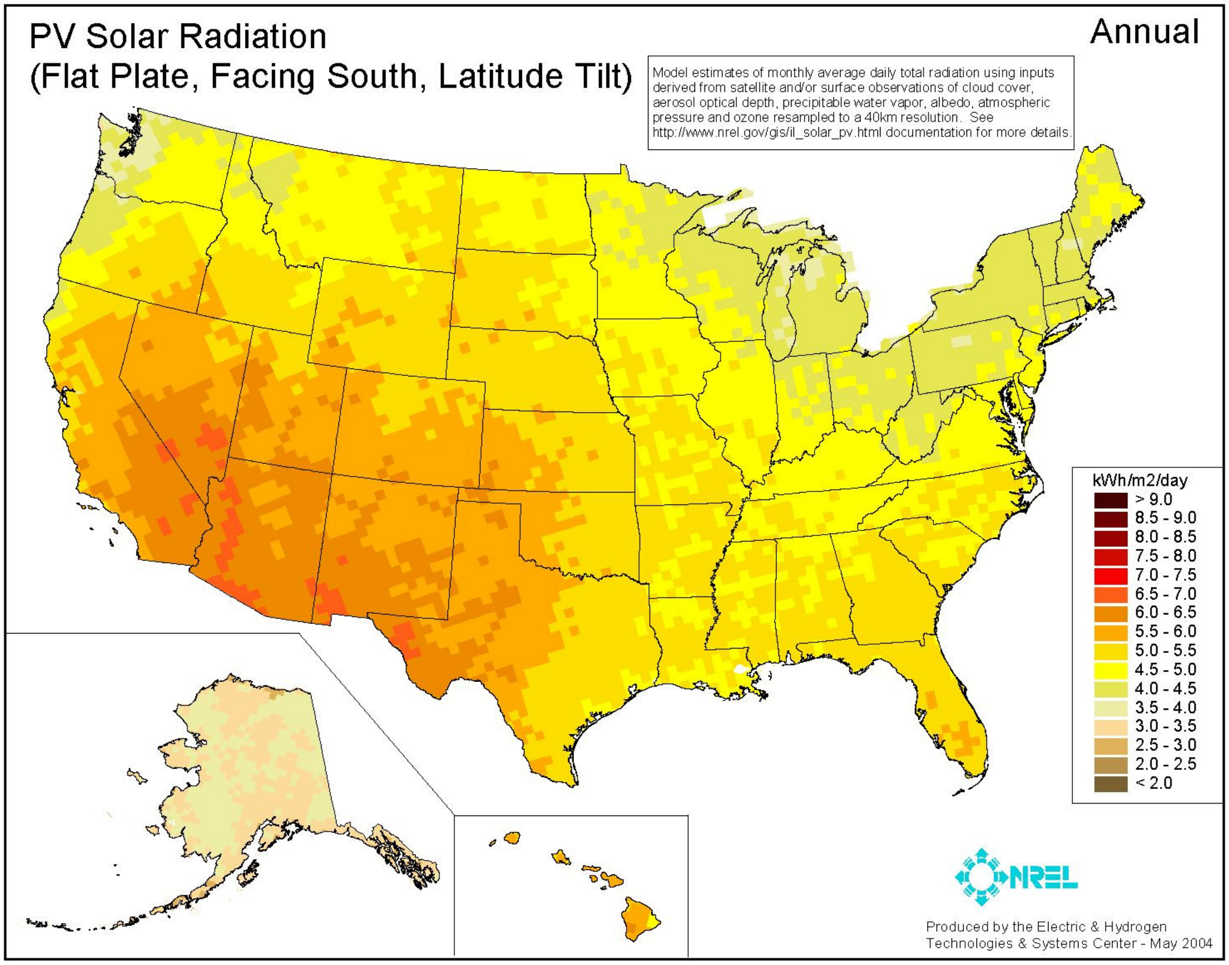


Figure 1.1: Solar radiation in kWh per square meter per day for the United States (NREL, 2004)

With regard to wind energy potential, with the exception of coastal areas, especially off-shore areas, where utility scale projects may be feasible, Rhode Island lacks substantial wind resources (Figure 1.2).

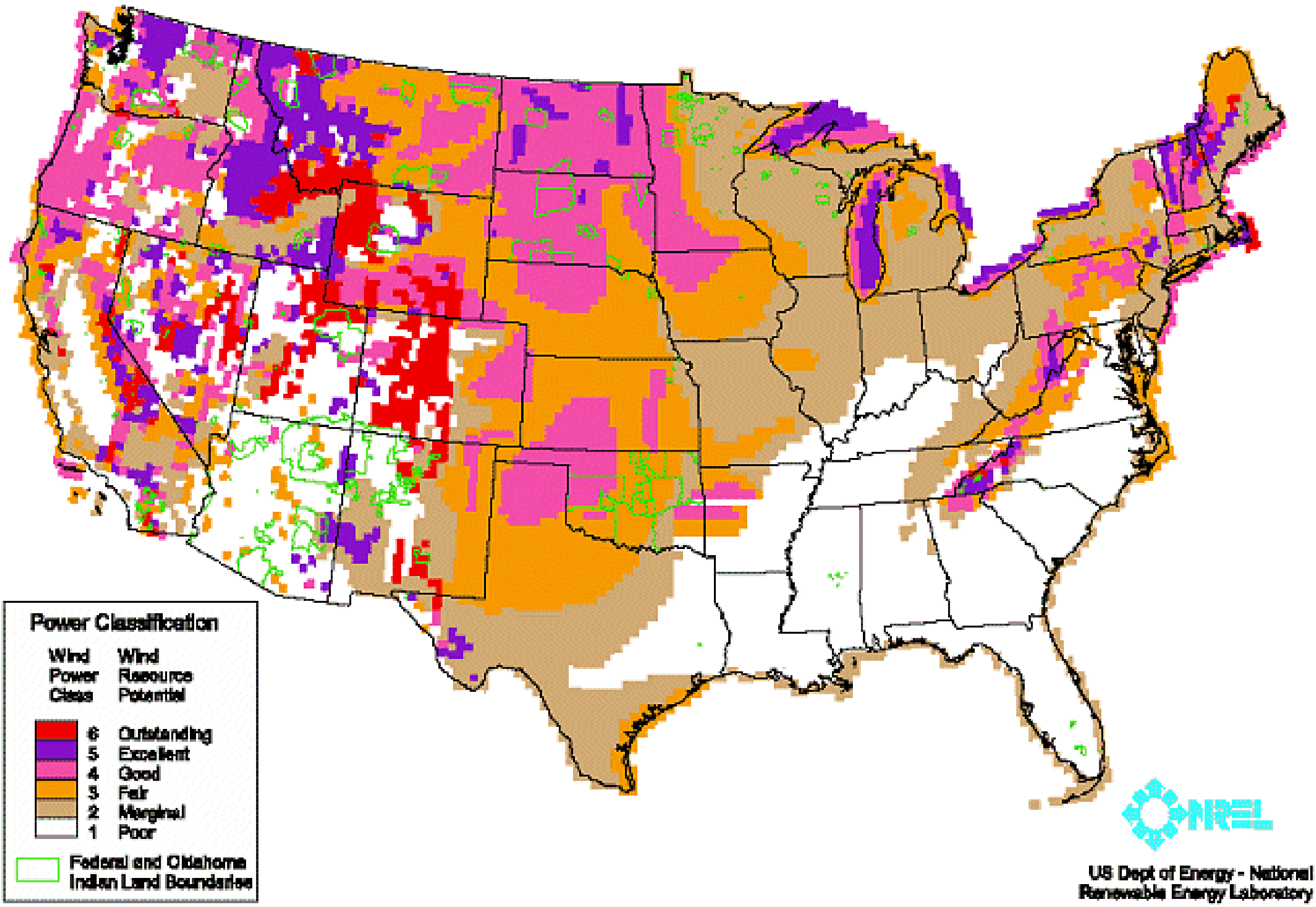


Figure 1.2: Wind Power Classes at 50 meters for the United States

Regarding hydro power potential, according to a 1995 study by the Idaho National Laboratory (INL), Rhode Island has 11.5MW of energy potential at sites that have a pre-existing dam, but do not have hydropower generation in place. In a 2006 assessment by the INL, Rhode Island had the second lowest potential for low power, small hydro (an approximate annual mean of 10MW) among the fifty states.

Regarding biomass potential, Rhode Island is small and densely populated and does not have significant forest acreages or industries, although over half of the land in the state is forested. According to the Department of Environmental Management, the average parcel size of forested land declined from 26 acres in 1973 to 13 acres in 1993, and "fuelwood is a leading forest product" in the state.

Electricity from the grid is the basis for the considering the economic viability of renewable energy the in Rhode Island. With the exception of Block Island, and a few small islands in Narragansett Bay, Rhode Island is comprehensively served by the electrical grid. There are not remote locations in the state where the choice is between on-site generation from non-renewable sources and renewable energy.

Considering the major potential sources of non-utility scale renewable energy, solar potential, although not strong, is widespread in the state and its development has a high capital cost. Wind potential is concentrated in coastal areas and its' development has a high capital cost, although not as high as solar. There are hydropower sites which are economically cost justified, however total available power generation potential is limited and permitting and regulatory barriers can be significant impediments to hydropower implementation.

1.6.2 Technology Conditions

Rhode Island has not been the location of renewable energy technology development or renewable energy system manufacturing. Renewable energy systems installed in Rhode Island are largely developed and manufactured elsewhere. Thus assessing technological conditions in Rhode Island is a matter of looking at technology and systems from other places and determining their availability in the Rhode Island market.

1.6.3 Institutional and Market Conditions

For more than sixty years, electricity in Rhode Island energy system was supplied by vertically integrated public utilities - geographic monopolies - which were regulated by the Public Utilities Commission. Government's role in energy was reactive. With the energy crises of the 1970s, that began to change. The State Energy Office was established by executive order in 1975; its policy responsibilities were moved to the Public Utilities Commission in 1981 and its programmatic responsibilities, largely for low-income energy assistance, were moved to the Governor's Office of Energy Assistance in 1985. Later these functions were housed in the Department of Administration.

In 1996, the Utility Restructuring Act (URA) ended the system of vertically integrated public utilities in Rhode Island. Electrical generating capacity was sold to non-regulated companies, while electricity transmission and distribution functions were retained by regulated utilities, distribution companies. Major distribution companies were consolidated under Narragansett Electric Company in 1999, a subsidiary of the New England Electric System, which in short order was acquired by National Grid. Significantly, Rhode Island has one distribution company serving 99 percent of the state. While the URA had economic benefits, it vitiated integrated resource planning.

In 2006 the Office of Energy Resources and the Energy Efficiency and Resources Management Council were established to provide Rhode Island with formal proactive capacities, with regard to energy issues, in the executive department of state government.

Since 2000, the General Assembly has consistently enacted legislation to support and facilitate renewable energy development. Rhode Island has been considered to have among the better arrays in the nation of such programs.

Yet despite all of this activity, renewable energy development in Rhode Island has been meager. There is little in the way of organizational infrastructure, adoption of innovations, and a competitive market. This report describes how the challenges, which Rhode Island faces, can be addressed.

2 FINDINGS AND RECOMMENDATIONS

2.1 Findings

According to the United States Energy Information Administration, Rhode Island has the lowest per capita energy consumption of any state. Electricity use is low because summers are moderate, resulting in less air conditioning demand, and because few homes use electrical heat. The US Census for 2000 showed that thirty percent of the dwelling units in the US relied on electric heat, while only 7.6 percent of Rhode Island did. However, residential electric rates in Rhode Island are the sixth highest in the nation.

Since energy cost is the product of use multiplied by price, the benefit to Rhode Island of low usage is offset by high cost. For the consumer, the value of renewable energy systems increase as the price of energy from non-renewable sources rises.

Rhode Island has been recognized as having among the better arrays of incentive programs for renewable energy in the country. However, as these programs apply to non-utility scale renewable energy resources, the current mix of incentives may not be as strong in actuality as they appear on paper. In an effort to make the Rhode Island renewable energy fund, which is supported by the Demand Side Management (DSM) program, self-supporting in 2013, as required by the Comprehensive Energy Act of 2006, the Office of Energy Resources in 2006 sharply curtailed incentives made to return money back to the Renewable Energy Fund. Assistance for residential solar and wind projects was capped at $300,000 per year for FY 2008 and FY 2009. For the year 2007, the Division of Taxation's *Tax Expenditure Report* found sales tax exemptions of $20,000, which equates to total sales subject to taxation of about $285,000.[40] In addition, income tax credits totaling $62,000 were claimed by 29 taxpayers, which equate to eligible expenses of $248,000 (total project costs may be greater than the allowed expenses, which are capped).

It is clear that non-utility scale renewable energy is not a robust area of economic activity in Rhode Island. This fact has a number of implications that bear on system reliability and least cost procurement.

To apply the phrase made popular by Malcolm Gladwell, smale-scale renewable energy has not reached a tipping point in Rhode Island (2002). Over the last three decades, there have been sporadic installations of renewable energy systems by innovators: people who tend to have big picture views and a capacity to take risks by trying things that are new and/or different. However, a smattering of innovators does not necessarily create an environment conducive to action by enough individuals to have an impact on energy systems. Rogers[43] has characterized the diffusion of innovation as involving: (1) knowing about an innovation; (2) being persuaded that the innovation has merit and is doable; (3) deciding to undertake the innovation; (4) implementing the innovation, and (5) confirming that the innovation is worthwhile, is meeting expectations, and warrants either continuation or rejection.

Being persuaded that an innovation has merit and is doable typically involves local knowledge. Does the innovation actually have relative advantage? Is the innovation compatible with community practices and community expectations? Is undertaking the innovation complex and difficult to do, or is it easy? Can the innovation be tested, can there be a trial, or does it require commitments that are difficult or expensive to unwind? Are functioning, successful uses of the innovation local observable: "If my neighbor can make a go of it, why can't I?"

Constraining factors in Rhode Island regarding non-utility scale renewable energy development would appear to be: the physical potential of renewable energy resources, the presence of embedded community practices that rely on and strongly favor non-renewable energy resources, the weakness of organizational infrastructure to support adoption of renewable energy installations, and the absence of market conditions that facilitate installing non-utility scale renewable energy systems.

With the regard to the physical potential of renewable energy resources, while the quality of renewable resources in Rhode Island is not so high that renewable energy projects are easily feasible, economically. Nevertheless, resources with economic value are present. Given that conventional energy sources are projected to continue to increase in price, developing costs-effective capacities to make use of renewable resources would appear to be a prudent investment, especially if undertaken strategically.

For two decades, from 1980 to 2000, the real price of energy declined, according to the Energy Information Administration. After rising significantly in the first two years of the new century, prices abated during 2001-2002, although they did not return to 1999 levels. Since 2003, prices have risen very sharply, and statements such as "we have reached the end of the era of cheap energy" have become commonplace. However, because an era may have ended does not mean that new, more responsive practices have become the norm. Embedded systems can have a life of their own.

Prior to 2006, Rhode Island had not established a comprehensive proactive capacity to address energy issues. While the OER, established by "The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006," has broad proactive governmental authority, it lacks capacity. The funding streams authorized in 2006 to support the OER have been a casualty of severely constrained state budgets. The OER cannot execute its statutory responsibilities given the constraints under which it is working. Thus, organizational infrastructure capacities that do not require exercise of governmental authority will in all likelihood have to be developed outside of the OER.

In addition to looking at organizational infrastructure, it is valuable to survey programs to support renewable energy development. Since energy prices began surging upward in 2000, there have been a series of enactments in Rhode Island to support renewable energy development in the state. Personal and corporate income tax credits were granted and a sales tax exemption was established in 2000. These were in addition to a 1980 law authorizing cities and towns to provide a property tax exemption for renewable energy installations. In 2001, the DSM fund was extended for five years, and in 2002 it was extended until 2013. The OER motioned to support only projects that were costs effective, from the use DSM renewable energy program in 2006. This policy change was part of OER's plan required by law to make the renewables program self-sustaining by 2013. The implementation plan has been memorialized in the OER's *Renewable Energy Plan* of April 9, 2008.

In 2004, the renewable energy standard was established requiring the distribution company and non-regulated power producers to acquire from renewable resources a specified portion of the electricity sold to Rhode Island users (the portion increases to sixteen percent by 2020) or to make alternative compliance payments. The alternative compliance payments are to be used to support renewable energy development. The fund holding the alternative compliance payments is to be administered by the Economic Development Corporation.

In 2005, the personal and corporate income tax credit was enhanced by fixing the credit at twenty-five percent of the cost of the system, up to a capped total system cost that depends on the type of the system.

The General Assembly enacted "The Comprehensive Energy Conservation, Efficiency, and Affordability Act" in 2006, which established system reliability and least cost procurement requirements, a demand side management program for gas distribution companies, the OER with broad authority to work proactively on energy issues, and the Energy Efficiency and Resources Management Council (EERMC). The 2006 Act gave the executive branch of state government explicit proactive capacities to address energy issues.

In 2007, the General Assembly provided a statutory framework for the state to participate in the Regional Greenhouse Gas Initiative (RGGI), a cap and trade program for carbon emissions from electrical generating facilities in the region, and specified that proceeds from the sale of the allowances could be used to promote the development of non-carbon emitting renewable energy resources. In 2007, the General Assembly also enacted expectations for net metering that set a minimum total of projects subject to net metering at five megawatts and a maximum individual project size at one megawatt and at 1.65 megawatts for municipal and Narragansett Bay Commission projects.

In addition to authorizing financial incentives, the General Assembly has sought to mitigate regulatory burdens and complexity. In 2001, it authorized the use of high performance building codes, such as LEED, and strengthened state planning requirements. In 2006, it mandated that the State Planning Council "amend and maintain as an element of the state guide plan or as an amendment to an existing element of the state guide plan, standards and guidelines for the location of eligible renewable energy resources and renewable energy facilities in Rhode Island with due consideration for the location of such resources and facilities in commercial and industrial areas, agricultural areas, areas occupied by public and private institutions, and property of the state and its agencies and corporations, provided such areas are of sufficient size, and in other areas of the state as appropriate." This plan was to be adopted on or before July 1, 2007 (RIGL 42-11-10 (f) (7)). The purpose of this provision was to simplify planning and zoning issues affecting renewable energy installations.

The General Assembly made provision for reasonable back-up rates for on-site electrical generators in 2002 and in 2007 it addressed net-metering, which is also a subject of one of the measures passed in 2008.

The general Assembly passed legislation in 2008, which was initiated in the Senate that has important basic changes for renewable energy development in Rhode Island. Senate Bill 2851 Substitute A (Chapter 348 of the Public Laws of 2008) as amended defines net metering, sets a cap on net metering at 2 percent of peak load, and establishes standards for crediting consumer accounts. The bill further sets size limits for net metered energy systems at 1.65MW generally and 3.5MW for municipal and Narragansett Bay Commission systems. Senate Bill 2852 Substitute A (Chapter 422 of the Public Laws of 2008) as amended consolidates administration of renewable energy assistance programs in the RI Economics Development corporation and allocates the lesser of $1,000,000 or 50 percent of the Renewable Energy Fund to municipal projects and the lesser of $200,000 or 10 percent of the Renewable Energy Fund to non-profit affordable housing projects. These two bills establish key parameters and priorities for non-utility scale renewable energy development.

2.2 Recommendations

The recommendations of this report accept axiomatically that the conditions conducive to non-utility scale renewable energy must be present for system reliability and least cost procurement of non-utility scale renewable energy to be successful.

A purpose of these recommendations are to establish clarity and fairness pertaining to non-utility scale renewable energy development. The recommendations accept that non-utility scale renewable energy can have intrinsic value socially and individually and that hedonic value can be an important basis for implementing projects by individuals and communities.

A recognized strategy for renewable energy potential realization is an infrastructure development model.[4] This report recommends that infrastructure development be given concerted attention in the near term (the balance of 2008 and calendar year 2009). Without more vibrant infrastructure capacities in the community it is unlikely that the potential for non-utility scale renewable energy can be realized. Consistent with the Rogers theory of innovation diffusion discussed earlier, the following steps should be taken to encourage adoption of renewable energy:

- Stronger mechanisms of **information sharing** need to be put in place, so that Rhode Islanders can easily learn what works, what does not, and why.
- **Regulatory reform** and clear procedures need to be put in place to reduce complexity and risk for viable projects. Protracted and unpredictable permitting processes add substantially to capital costs and to risk.
- **Markets** need to be made competitive. Specialized small business development and technical training can be offered.

- Measures to increase **consumer confidence**, such as certifications, can be put in place. Programs of financial assistance can be coordinated and given stability.

Attention to these tasks will support system reliability and least cost procurement; the target year for completing substantial progress on these action items should be calendar 2009. To provide overall coherence, a systems manager capacity will need to be established, which can be done either within state government or outside of it.

A second recognized mode of renewable energy potential realization is a project development model that is directed at supporting projects.[63] This report recommends developing this model in 2009 and making it fully operational for 2010 and 2011. In sum, system reliability and least cost procurement can be used to augment current programs in very targeted and resource specific ways.

As described in the findings section of this chapter, there are multiple potential resources that could be used to support project development. The recommendations set forth below do not need to rely on system reliability and least cost procurement decisions pursuant to 39-1-27.7.

Solar:

PV should be given additional support equal to an additional 1.5 times the energy portion of standard offer service to recognize that PV generates electricity during peak periods when it is most costly to the system.

Solar thermal system for single family residences, which have electric hot water and/or electric heat, should be given the same first year support, $3 per therm, as solar thermal systems for multi-family residences and commercial and industrial users. Support for solar thermal systems should complement appropriate support from the new gas DSM program.

Wind:

In locations with class three and four winds where towers of eighty to one hundred feet can be accommodated, a program of low or zero interest loans should be established for capital costs of residential/small commercial industrial turbines in excess of current incentives and subsidies.

Wind projects, especially municipal project, will be given support through Chapters 348 and 422 of the Public Laws of 2008, and system reliability procurement should take cognizance of this policy priority.

Small Hydro:

A grant program should be maintained to socialize the cost of determining project feasibility and permitting for projects using high hazard and significant hazard dams, where hydro-electric power appears economically reasonable. A program of low or zero interest loans should be established to make high initial capital costs bearable based on project revenues.

2.3 Conclusions

It is not presumed in this report that these measures for non-utility scale renewable energies will have a significant impact on system reliability and least cost procurement and energy procurement costs. Installing two or three small wind turbines, one small hydro-electric facility, and doubling the annual number of solar installation in the next two years would likely equated to about one-eighth of one percent of average kW demand in Rhode Island. The purpose of the initiatives set forth in these recommendations is to build capacities for non-utility scale renewable energy development in RI, so that as the technology evolves and cost conditions change, RI will be better positioned to secure the advantages of system reliability and least cost procurement as they pertain to non-utility scale renewable energy.

3 SOLAR

3.1 Background

The concept of generating electricity from solar energy has existed since the 1800s. However, the first major usage of solar cells was in space exploration in the mid 1900s, with the modern solar cell being developed in the 1950s. Commercial use of solar power was first spurred by the energy crisis of the 1970's. Since then, interest has increased steadily, now attaining rapid growth rates (~25 percent per year). The United States was the leader in solar development and implementation until the early 2000s, when Japan and Europe began to surpass it.

3.2 Technology

Photovoltaic shingles on the roof of the URI College of the Environment and Life Sciences Outreach Center.

Solar energy serves several different functions as a form of renewable energy. A common view of solar energy is in rooftop photovoltaic arrays. Photovoltaic (PV) cells convert light energy from the sun into electrical energy. A set of PV cells make up a PV module, or "solar panel", and modules are combined to make an array. Another typical method to utilize solar power is found in solar thermal energy. Solar thermal energy works by harnessing the sun's rays to provide energy in applications such as water heating, space heating, and pool heating. Due to the varying functions of solar systems, the technology differs greatly between photovoltaic and solar thermal systems.

Solar arrays can be fixed in place or allowed to track the movement of the sun. Tracking systems have higher initial costs, but produce more electricity than fixed systems because the amount of sunlight impinging on the array is always maximized.

The photovoltaic material in the array is typically silicon, though thin films and nanocrystals are both being researched and used. The use of silicon contributes to the price of solar cells, as it is currently a costly material due to high demand in all electronics/technology fields.

3.3 Incentives

3.3.1 Rhode Island Incentives

In Rhode Island, financial incentives for solar energy installations, include property and sales tax exemptions, a personal and corporate income tax credit, and a solar thermal rebate. The property tax exemption applies to residential solar water heating, solar space heating, and photovoltaic systems (Appendix E: RI-6). Rhode Island residents and business owners can also receive 100 percent sales tax exemption on solar products such as solar electric systems, inverters for solar electric systems, solar thermal systems, and manufactured mounting racks and ballast pans for solar collectors (Appendix E: RI-7). Individuals and businesses are eligible for an income tax credit of 25 percent of the costs for a solar system. To receive the credit, the system must cost less than $15,000 for PV and active solar space heating, and less than $7,000 for solar hot water (Appendix E: RI-1, RI-3). National Grid offers a one-time rebate of $3 per therm, or 100,000 BTUs of estimated first-year savings to its commercial, industrial, and multifamily customers for the installation of solar thermal technologies. The incentive may offset up to 50 percent of the project costs with a maximum of $100,000 per project (Appendix E: RI-8). During the 2008 fiscal year, commercial, industrial, nonprofit, local government, state government, and institutional sectors are eligible for photovoltaic grants in the amount of $3.50/watt DC for non-


Solar thermal array seen along Route 10 in Cranston.

profits and $3/watt DC for for-profits, up to $87,500 for non-profits and $75,000 for for-profits (Appendix E: RI-16).

Rhode Island has a few non-financial programs which facilitate the installation of small-scale solar. For example, solar easements protect rights to solar access. In other words, if a homeowner installs a solar array, laws exist to allow the creation of written documents preventing a neighbor from doing something that might block sunlight to the array, such as planting a large tree or building a large structure. Solar access laws ensure that homeowner investments in solar energy will continue to generate power and revenue without physical disturbances from beyond their property (Appendix E: RI-15). Rhode Island also has a net metering policy that allows commercial, residential, and industrial solar system owners to sell excess electricity back to the grid (Appendix E: RI-12). Despite this variety of incentives, it is not easy for the public to access this information; the only incentive listed on the RI Office of Energy Resources website is the tax credit. Public awareness is an essential, yet wholly underdeveloped, component of the RI small-scale renewables market.

3.3.2 Incentives in Other Jurisdictions

Among the New England states, Connecticut has a relatively comprehensive set of solar incentives. In addition to property and sales tax exemptions, Connecticut has a loan program for PV, solar hot water and solar space heating, as well as grant and rebate programs for PV. One of the grant programs is specifically intended for on-site renewable energy generation by businesses, industries, schools, local government, state government, and institutions. PV systems that are greater than 10 kW and are configured to participate in ISO New England's demand response program are eligible to receive up to $2.5 million (Appendix E: CT-7). Another grant program which has been highly successful is Connecticut's community grant program, which provides eligible communities with a $5,000 block grant to support local public awareness and education projects that promote renewable energy (Appendix E: CT-6).

Connecticut is well positioned to support small-scale renewable energy projects. Its public benefits fund, the Connecticut Clean Energy Fund (CCEF), is administered by a separate entity called Connecticut Innovations (CI). CI was created by the legislature with the mission to "provide strategic capital and operational insight to push the frontiers of high-tech industries such as energy, biotechnology, information technology, and photonics". The CCEF takes 1 mill per kWh from ratepayers for renewables. Other funds come from returns on investments made by CI. Connecticut also has a few important non-financial incentive programs such as solar permitting standards, solar contractor licensing and training, and PV interconnection standards. Additionally, there is no limit on overall enrollment in Connecticut's net metering policy.

Like Connecticut, many of New York's incentive programs are administered by a separate entity known as the New York State Energy Research and Development Authority (NYSERDA). NYSERDA is a public benefit corporation created by legislation in 1975 that administers many of its incentive programs with funds from the state's system benefits charge. NYSERDA offers a variety of small-scale solar incentives, such as grants for renewables research and development, PV rebates, incentives for business growth, loan programs for all types of solar, and interconnection standards for PV and solar thermal. The Energy $mart New Construction Program encourages the incorporation of energy efficiency and renewable-energy resources into the design, construction and operation of commercial, industrial, institutional and multi-family buildings through rebates (Appendix E: NY-13).

Photovoltaic array on the roof of Park View Middle School in Cranston.

This program has a support system that walks potential participants through the process and helps them to better understand the incentives and how they can benefit from it. Assistance of this type relieves the burden on consumers to research and apply for incentives. The added support system strengthens the market as consumers become aware of their financial options. Program and market stability is improved because customers are more likely to follow through with small-scale development. Some NYSERDA programs also apply energy generation caps based on the amount of energy a site uses. This provides a safeguard for the utility, minimizing the risk of significant revenue loss to net metering laws, and is particularly useful in demand-response programs to ensure that participants cannot generate excess energy in order to sell it back to the utility at a profit.

As in New York and Connecticut, the Massachusetts Renewable Energy Trust is administered by a quasi-public agency, the Massachusetts Technology Collaborative (MTC) which is the state's development agency for renewable energy and the innovation economy. Massachusetts also has a variety of solar incentives, including solar rebates, community and residential grants, tax credits and exemptions. One of the more specialized incentives in Massachusetts is a loan program to support renewable energy companies that currently, or plan to, manufacture renewable energy technology products. Through this program, manufacturers can receive up to 50 percent of capital expenses and related spending over a 24-month window, providing a worthwhile incentive for businesses to enter the local solar market in Massachusetts.

3.4 Physical Potential

Solar irradiance represents the amount of sunlight that falls on a given area. It is measured in light power per unit area upon which it falls, such as kW/m^2. It varies widely on a global scale, generally increasing with decreasing latitude. Amongst the most important factors affecting solar irradiance is altitude. High altitude regions such as Colorado receive much more solar radiance because sunlight does not travel as far through the atmosphere before reaching the earth. The angle of the sun is also a major factor. During winter months, the sun is at a lower angle in the sky and therefore its light must pass through more atmosphere to reach the ground, thus increasing losses. Other factors such as cloud cover, atmospheric water vapor and trace gases, and the amount of aerosols in the atmosphere all affect solar irradiance on both the short (minutes-hours) and long (annual average) time scale.

The Climatological Solar Radiation Model[18] developed by NREL for the U.S. DOE provides estimates for annual averaged daily total solar irradiance (kWh/m^2day) on a 40x40 km grid across the U.S. The model uses the above criteria with an eight year histogram of monthly average cloud cover. The output irradiance is in kWh/m^2day, equal to 1/24 kW/m^2. It is assumed that the flat plate collector is oriented southward at an inclination angle equal to the latitude of its location (about 41.5^0 North for RI). The unit output should be read as the amount of solar energy (kWh) that impinges upon an area (m^2) angled at the location's latitude, over the span of one day.

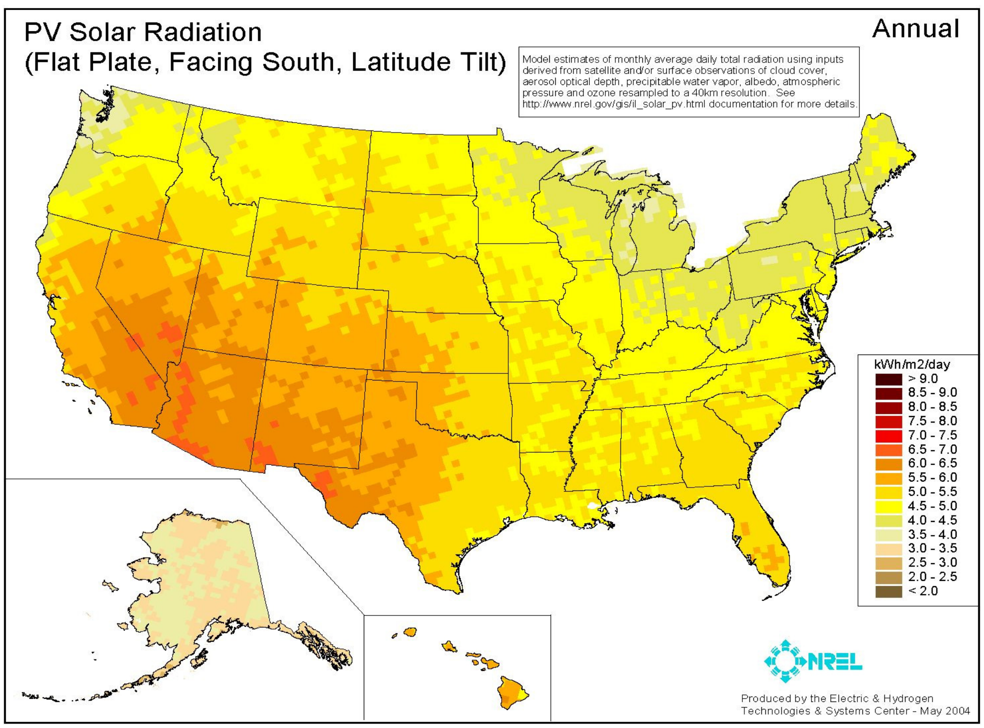


Figure 3.1: NREL Model Solar Irradiance—Annual

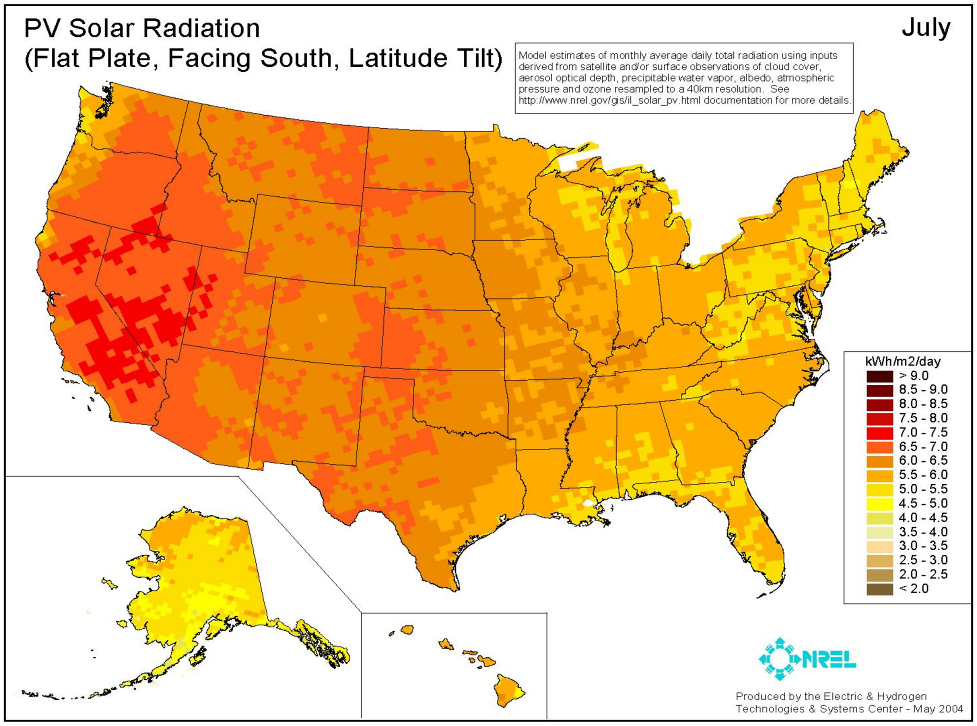


Figure 3.2: NREL Model Solar Irradiance—July

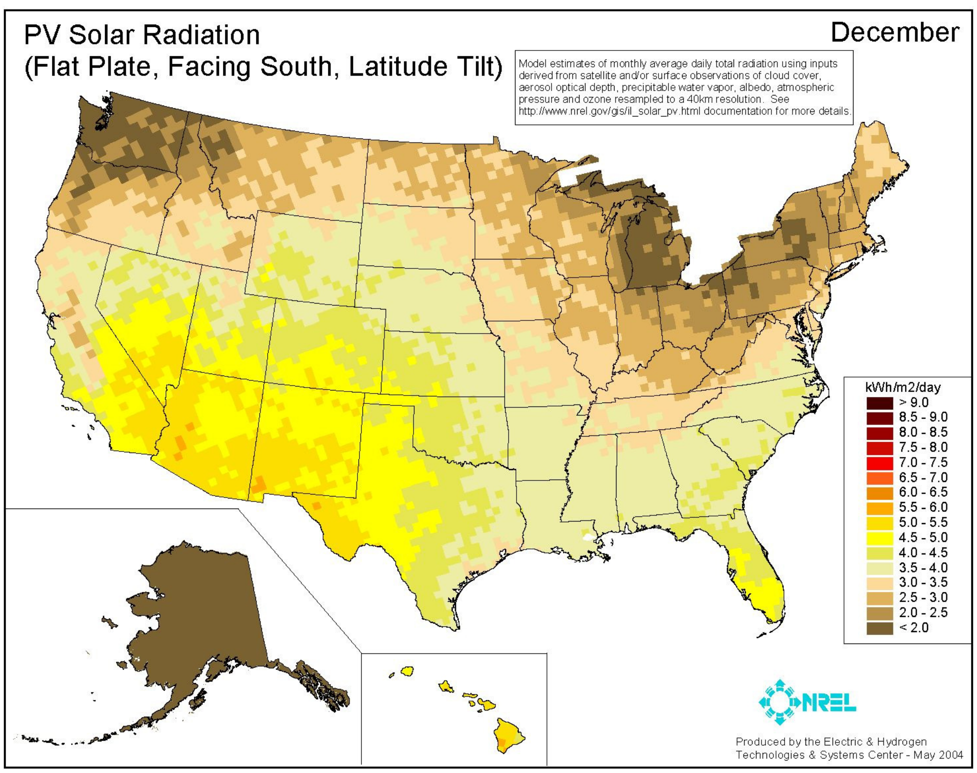


Figure 3.3: NREL Model Solar Irradiance—December

Figures 3.1-3.3 show the NREL solar irradiance model for annual average, July average, and December average values. Rhode Island falls within one of two grids, the first covering the top two-thirds of RI and the second covering the bottom third. These two grids differ by 0.5 kWh/m^{2}day on each of the maps. The daily energy generation ranges from 2.5-3.5 kWh/m^{2}day in December to 5.0-6.0 kWh/m^{2}day in June and July, with an annual average of 4.0-5.0 kWh/m^{2}day.

To consider the raw potential of solar PV energy here in RI, the total amount of solar irradiance that falls on RI on an average day in June or July is 16,977,600,000 kWh (16,977.6 GWh). And the total energy that falls on the state of RI over the course of one year is 5,049,260 GWh. The total annual electricity usage in RI is 7,888 GWh[51]. Therefore, assuming a 10 percent conversion rate from solar to electricity, covering 1percent of the state's land in solar panels would cover 65 percent of the state's energy needs.

3.5 Photovoltaics Analysis

To determine the incentives necessary to make PV financially viable to the end-user, this study includes a simple cost-benefit analysis from the perspective of the end-user. The deficit that remains after this analysis represents the capital that must be paid back to the end-user as some form of incentive (tax credit, net metering, etc.) to make the project financially viable. This report then attempts to determine whether the cost of this incentive can be justified to the utility, by means of avoided costs, in a more in-depth cost-benefit analysis from the utility's perspective.

3.5.1 Assumptions

Typically, photovoltaic systems cost around $5,000/kW, with small-scale systems being on the order of 1 kW. Installation costs range by project, but are typically around 40percent of total installed costs. Thus, average small-scale PV turnkey costs can be approximated as $8,400/kW. Operation and maintenance costs are very low for PV systems and will be considered negligible for this study. It should be noted, however, that inverters on PV systems have shorter lifecycles (5-10 years) and represent a significant cost ($0.50-$2.00 per W). The extremely wide variability of inverter prices, as well as the complex and dynamic factors involved in inverter pricing [30], make a "typical" price difficult to choose. Therefore, the assumed price of $1,000/kW and replacement once every seven years (three times over the 25 year system lifecycle) should be noted with caution. Also, for the purposes of this analysis, it has been assumed that system performance does not degrade with time. While this is not representative of actual performance, no information is available.

3.5.2 End-User Cost-Benefit Analysis

Based on these assumptions, a cost-benefit analysis from the end-user's perspective yields an estimated life-cycle cost of $9,690/kW and lifecycle revenue of $3,520. This leaves a net deficit of $6,120/kW. If the 30 percent Federal incentive is factored in, the life cycle cost is reduced to $7,180/kW and the net deficit to $3,660/kW. A timeline over system lifespan of these costs and benefits is shown in figure 3.4. To compensate for the deficit, a 44percent of turnkey cost incentive would be necessary, assuming the Federal incentive is in place. Without the Federal incentive, this rises to 74 percent.

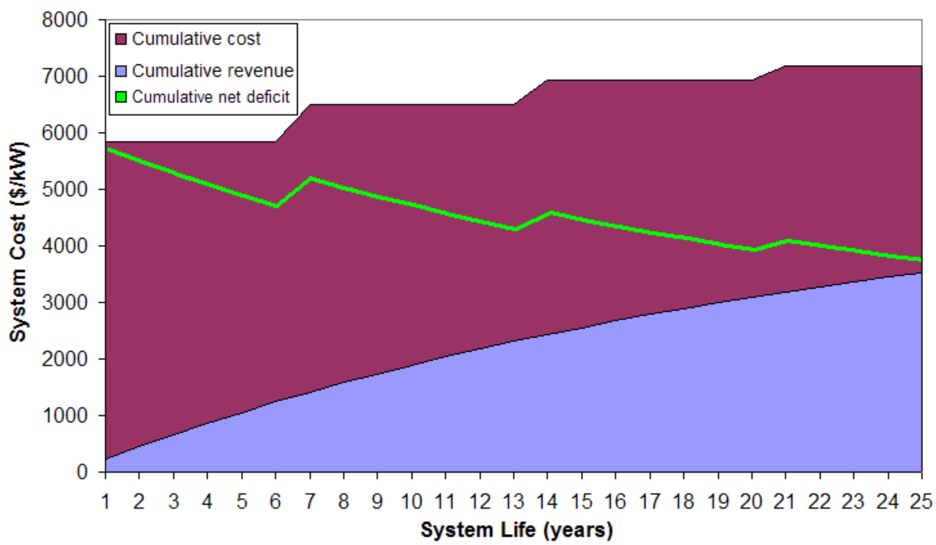


Figure 3.4: Cumulative cost and revenue to the user in dollars per kW for the tax credit incentive.

The use of a low interest loan—whose interest rate is equal to the inflation rate—would significantly reduce the costs in this study because the turnkey costs are then spread out over time and are therefore subject to the effects of the discount rate. Assuming a 10 year loan, the net deficits become $4,690/kW and $2,320/kW without and with the Federal incentive, respectively. For a 15 year loan (illustrated in figure 3.5), these deficits drop to $4,020/kW and $2,160/kW. This sum of money must then be recovered via some other incentive.

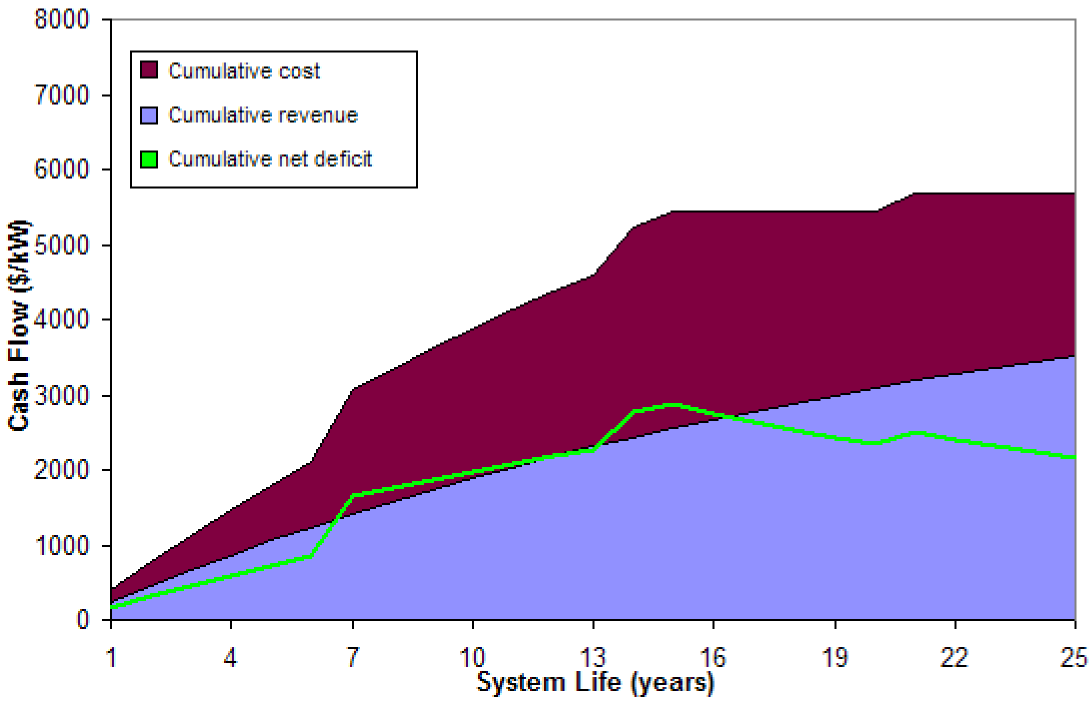


Figure 3.5: Cumulative cost and revenue to the user in dollars per kW for a 15-year low-interest loan incentive.

3.5.3 Utility Cost-Benefit Analysis

As has been shown above, use of a low interest loan is more economically viable than a direct initial cost incentive and is therefore the scenario considered in this analysis. Using the avoided costs of line losses and transmission capacity, the lifecycle revenue is estimated at $280/kW. This is far below the $4,020/kW or $2,160/kW cost estimates. However, the true savings from PV power generation have not yet been taken into account.

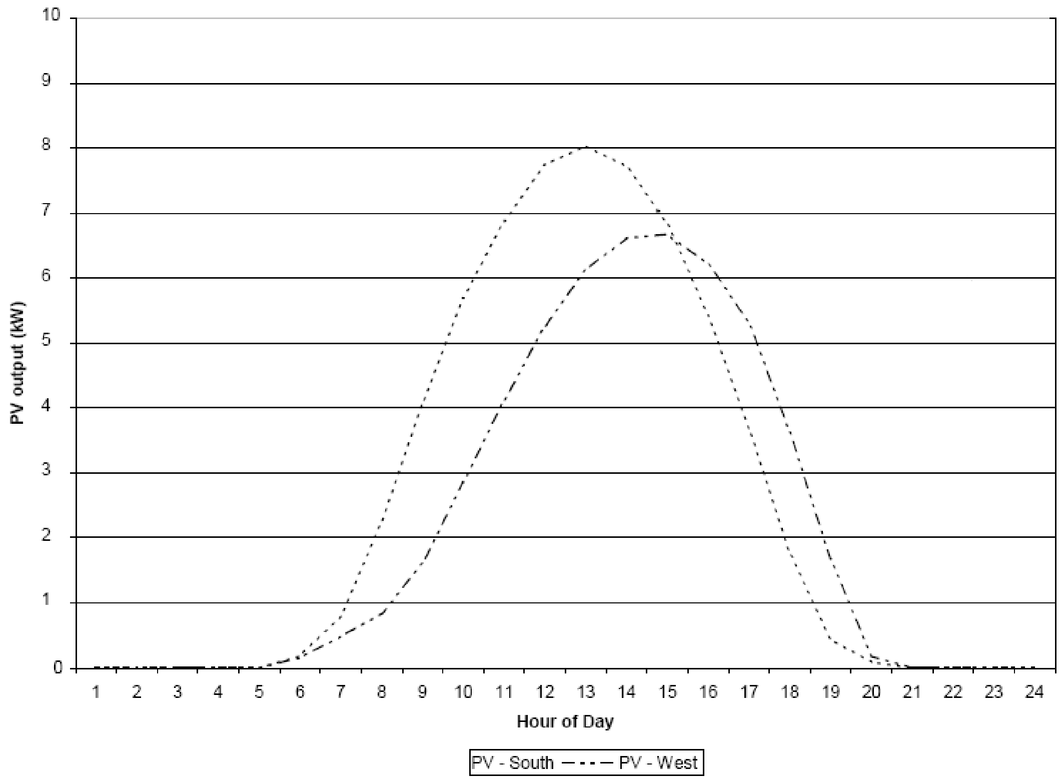


Figure 3.6: Hour of Day PV Output[5]

Because their energy is derived from the sun's rays, PV cells produce the most power while the sun is highest overhead. This applies both to time of day (figure 3.6), and of year (figures 3.1-3.3). Because PV's energy production is not uniform, the worth of its energy should not be considered uniform.

The price of energy at the utility level is highly variable due, in large part, to the variation in demand. On an annual scale, the coldest times of the winter and hottest times of the summer tend to yield the highest prices, with the summer yielding significantly higher extreme peaks. On a daily scale, prices tend to follow a curve that matches the temperature, peaking around 3:00 PM (15 hours).

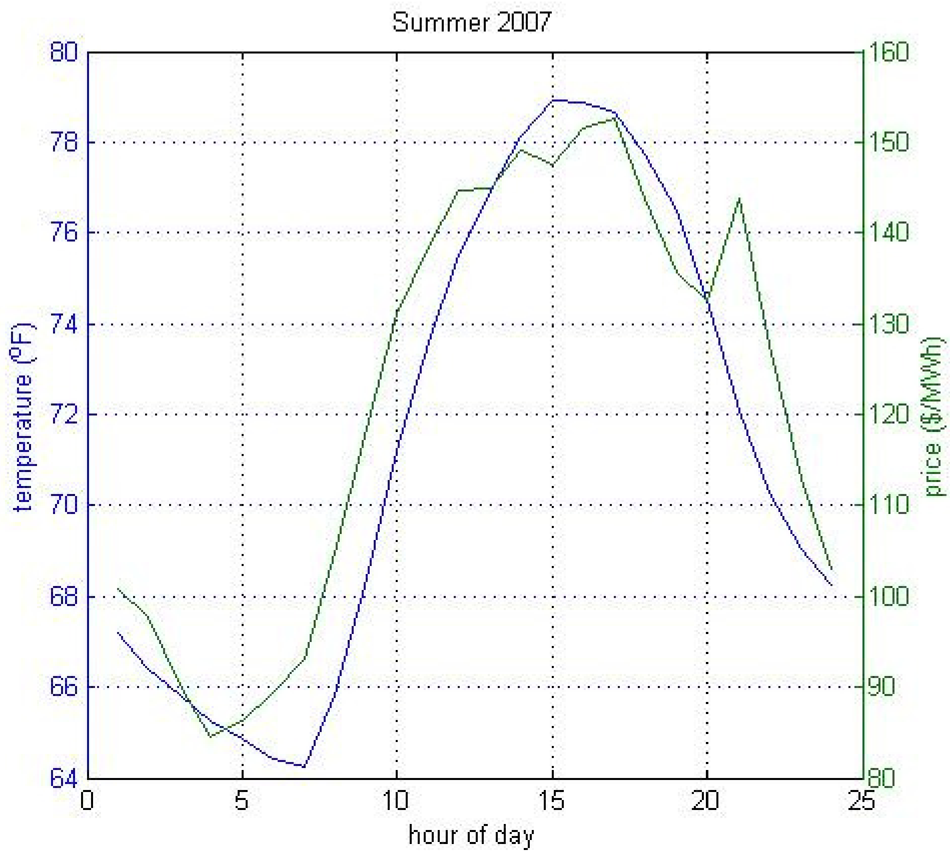


Figure 3.7: Summer Hour of Day Demand and Temperature

This trend varies somewhat by season and is most apparent in the summer. Extreme prices also occur during the hottest days of the summer. The extremes correlate to brighter sunshine and, therefore, higher PV output.

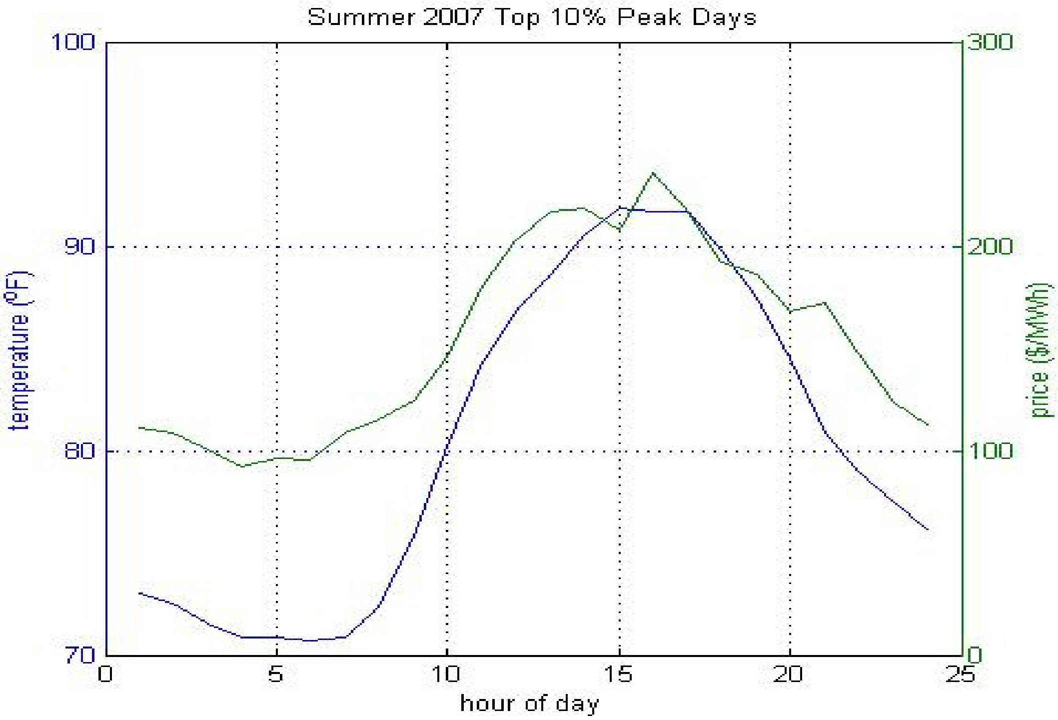


Figure 3.8: Peak Summer Hour of Day Price and Temperature

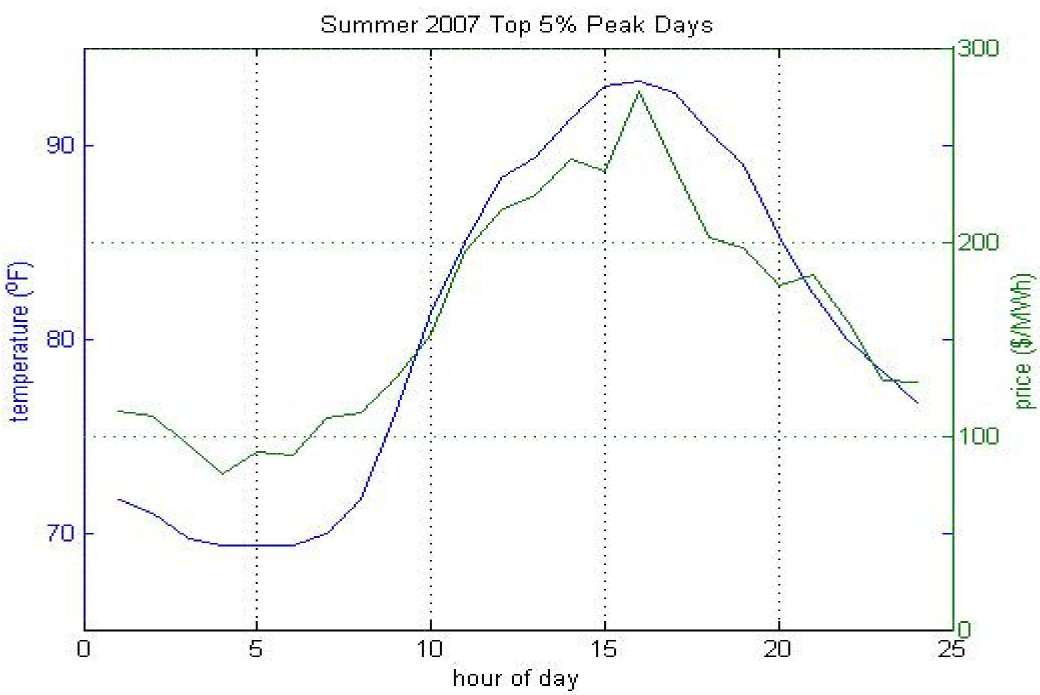


Figure 3.9: Extreme Peak Summer Hour of Day Price and Temperature

These peak prices cost the utility significantly more money than is being generated by energy sales at peak times because of the flat rate charged to end-users. Therefore, significant cost reduction can be achieved by the utility by reducing load during the peak hours. Programs such as demand-response already attempt to address peak load use.

The true value of energy generated by PV, therefore, is significantly greater than what is calculated by the retail energy price. While it is difficult to determine the actual savings to the utility by PV due to its generation at peak conditions, considering the increased cost associated with peak demand does give a rough estimate. In Connecticut in 2007, the top 2percent highest loads represented 3.2 percent of the annual usage and 5percent of annual energy costs. This means that, including base costs, this peak energy production cost 2.5 times as much as average production[3]. The same study found that 10percent of peak loads represented 19 percent of costs, a factor of two.

Approximately 50 percent of the daily energy generation of a south-facing PV cell comes during the hours of 11:00 AM to 3:00 PM. This peak time can be adjusted to match the peak price hours of 1:00 to 5:00 PM by angling the PV cell toward the west, as illustrated by figure 3.6. For larger solar arrays, a tracking mechanism can be used to have the solar array follow the sun, maximizing the sunlight absorbed at all times.

3.5.4 Analysis Discussion

The power generated by PV is significantly undervalued, considering its correlation to price/demand on three scales: (1) seasonal; (2) hour-of-day; (3) extreme peak. It is difficult to determine what the actual value of power from PV is, however, because such an estimate would require hourly PV power generation data from a large number of PV arrays. No such data are available and a simulation is beyond the scope of this study. As such, with a variety of assumptions, power generated by PV has been estimated to be worth 150 percent of retail price. If these savings were passed on to the end-user, the cost, revenue, and net deficit timeline becomes figure 3.10.

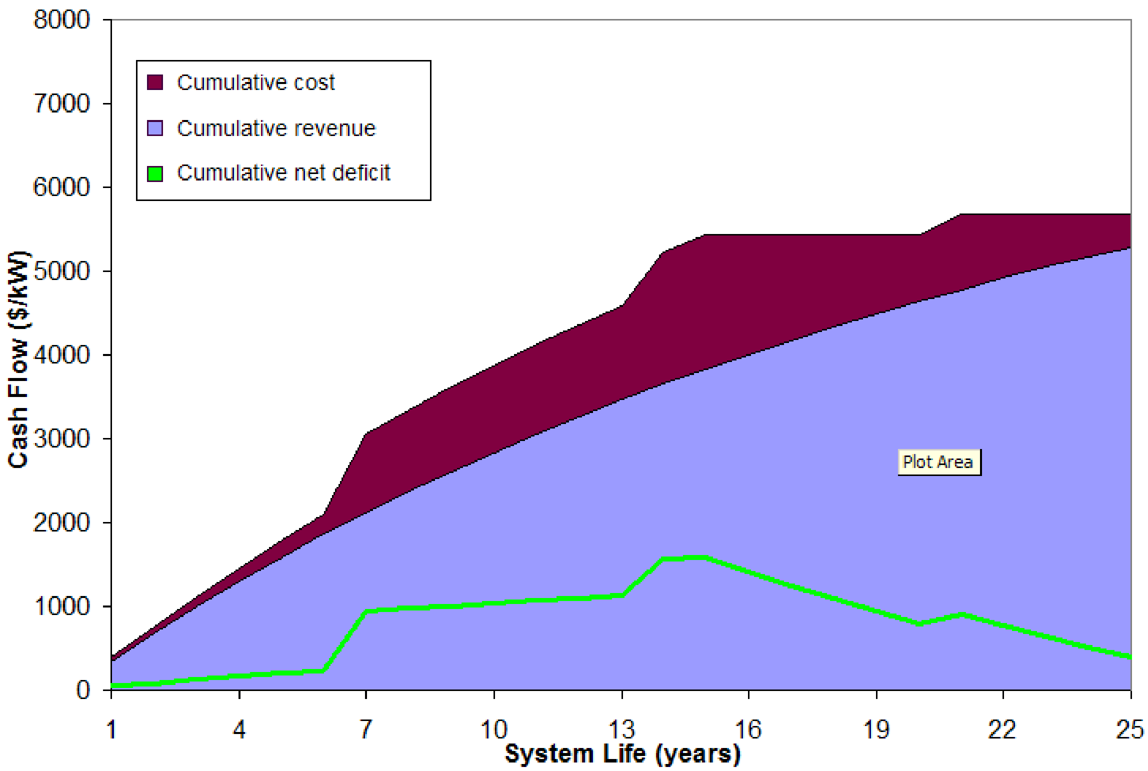


Figure 3.10: 15 Year Low-Interest Loan and 150 percent Power Valuation

The net deficit over system lifespan becomes $400/kW. This sum is less than 10percent of initial system cost and is nearly negated if the avoided cost of line losses ($280/kW) is taken into account.

An alternative scheme to a flat 150percent boost to PV power worth would be real-time monitoring of PV output. This would then allow PV panel owners to be paid in a manner similar to power plants, with a wholesale rate being applied to all power generated by the solar cells. While this scheme may not be worth the additional associated costs, it is likely of interest to do on a small scale so as to gain further information on the actual worth of PV power.

3.6 Conclusions

The barrier due to PV's high initial cost should be overcome with a low-interest loan program covering 50percent of turn-key costs. Using a loan instead of a tax credit reduces the initial cost barrier while still minimizing the cost and risk to the system. And because the loan must eventually be paid back, it also makes cost minimization desirable from the end-user perspective.

A more in-depth analysis of the actual worth of PV electricity may be needed to fully account for its time-varying nature. Many factors are involved in this and proper simulation of these factors is important in determining the true worth of its power. However, this report cautiously suggests that real-time power generation monitoring may be a superior approach. This technique would allow the actual worth of the power generated by a PV system (calculated using real-time power generation and wholesale pricing) to be realized. This could then be used as payment to the end user, benefiting the utility by avoiding the costs associated with line losses. While this approach would require monitoring equipment to be provided by the utility, due to the small size of RI, the equipment might be no more costly than such an analysis. Additionally, this might serve as an initial step toward real-time monitoring of total end-user power consumption.

3.7 Solar Thermal

Data on solar thermal systems is very limited. However, a general consensus amongst solar energy advocates suggests that solar thermal—particularly solar hot water—is a more economically feasible technology than PV. It is therefore prudent that some level of investigation into the technology be performed if PV is to be invested in.

Solar water heaters and space heaters are constructed of solar collectors. Solar collectors absorb the sun’s energy, transforming its radiation into heat, and transfer the heat to water, air, or other medium. This is typically done either by directly pumping water through the collector, or by using a fluid that may then transfer its heat to water. A typical flat-plate system is an insulated metal box with a glass or plastic cover, called the glazing, and a dark-colored absorber plate. The tubing may also be surrounded by an evacuated glass casing. This prevents heat loss by conduction and convection, as there is no air to absorb heat from the piping.

The effectiveness of a solar thermal system depends on all the same factors as PV (system orientation, size, and angle toward sun). With further study into solar hot water, it may turn out that the system acceptance suffers the same maladies as gas-thermal heap pump systems, whose high initial costs and low public awareness result in few applications. It is therefore suggested that solar thermal system for single family residences, which have electric hot water and/or electric heat, should be given the same first year support , $3 per therm, as solar thermal systems for multi-family residences and commercial and industrial users. Support for solar thermal systems should complement appropriate support from the new gas DSM program. It may also be advisable that low-interest loans be put into place for those who do not have electric heating, as the savings to the utility are not immediately apparent, but nonetheless present as they are in the case of GHP.

4 WIND

4.1 Introduction

Jamestown windmill built in 1787.

Wind power has had a long presence in Rhode Island. A windmill, dating back to 1787, driven by the sea breeze in Jamestown provided power for the grist mill[25]. The largest on-site wind project is the 660 kW unit at Portsmouth Abbey school that came online in 2006[34].

Numerous residential size turbines are currently in use in RI, a few of which have been supplying clean energy for decades. For residents with particularly high electric bills, such as those on Block Island, these turbines provide an alternative low-cost energy source. These projects are an excellent example that with proper wind resources and turbine siting, small scale wind energy can be successful in Rhode Island.

Another use of wind energy that is not emphasized in this report is community scale wind energy. A residential turbine provides energy to just one household. A community scale turbine could provide energy for an entire development or community. Future research on such projects should not be undermined. RI has a limited amount of private open space to accommodate turbines, so having one larger turbine versus 10 small ones might be more practical. These types of projects would require substantial collaboration between authorities, homeowners, the utility and developers.

This report aims to outline the components of wind technology along with its use and feasibility in Rhode Island. Particular attention should be spent on the conditions detailed that make this technology cost-effective.

4.2 Technology

Small-scale wind turbines range from 1-10 kW, and are designed to be installed at homes, farms, and small businesses. Based on load size, very few individual consumers will have the need for large scale wind turbines. Wind energy is less predictable, but available for more hours in a given day than other renewable sources. In grid-connected applications, energy produced can be used to offset utility power and reduce electricity bills. In non-grid connected applications a turbine can alternatively be used for water pumping and battery charging.

The amount of energy available in the wind at a location is equal to the cube of the wind speed[45]. As a result, little energy can be harnessed from light breezes, while an overabundance of energy is available in high winds. Even a small increase in wind speed leads to a large increase in energy output. Emphasis should therefore be on choosing an appropriate location with consistently strong wind speeds, rather than on a turbine's ability to run at low wind speeds.

Wind systems are made up of three major components: a turbine, a generator, and a platform (Figure 4.1). Turbines typically consist of 1-3 blades, which comprise the rotor. Blades are made of fiberglass or wood, and are aerodynamically designed to spin at high speeds to capture the maximum amount of energy from the wind. Wind turns

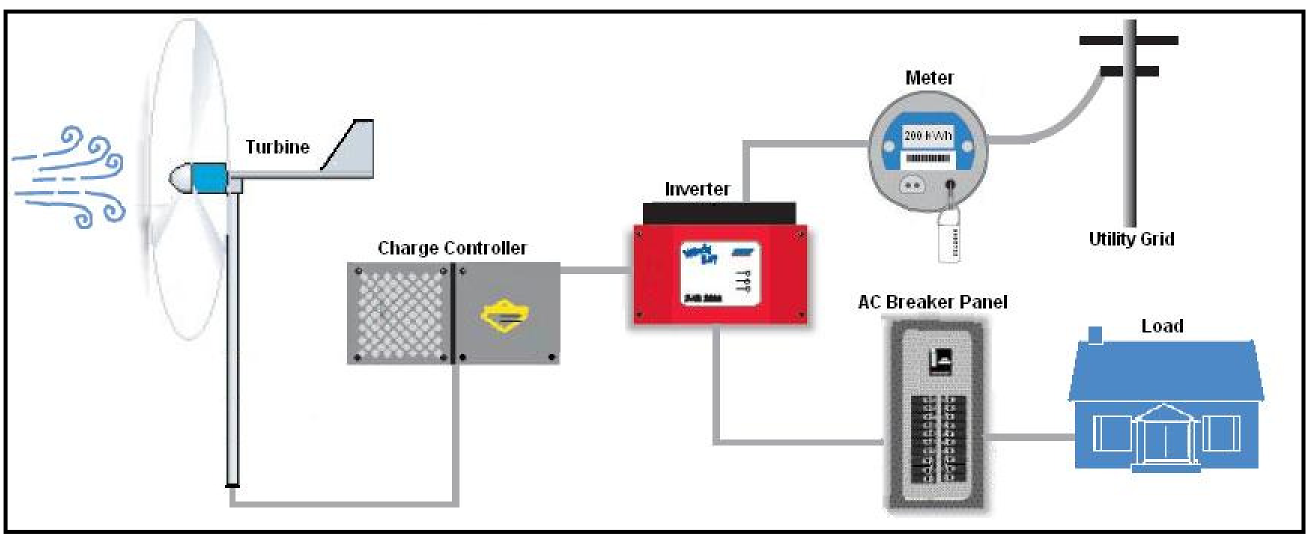


Figure 4.1: Typical wind system components.

the blades and spins an internal shaft. The shaft is connected to a generator that creates electricity. The turbine can also have a tail located behind the rotor, which aligns it to the wind. The generator is connected to the electrical system and consists of an inverter, a meter, circuit breaker, wire run, and a conditioning unit. The platform, or foundation, is made of steel or concrete and provides adequate support for the tower and guy wires.

It has been suggested that turbine siting requires at least one acre of land to ensure adequate space for the tower, maintenance, and clearance from obstructions.

Power is created by converting the kinetic energy of the wind into a torque which acts on the blades. The amount of energy transferred to the rotor depends on the density of air, the rotor area, and wind speed. Turbines start running at the manufacturer designated, "cut-in speed", somewhere between 3-5 m/s (6.7-11.1 mph). Likewise, turbines are programmed with a "cut-out speed" of around 25m/s (55 mph) to avoid damaging the turbine or its surroundings at high wind speeds[1].

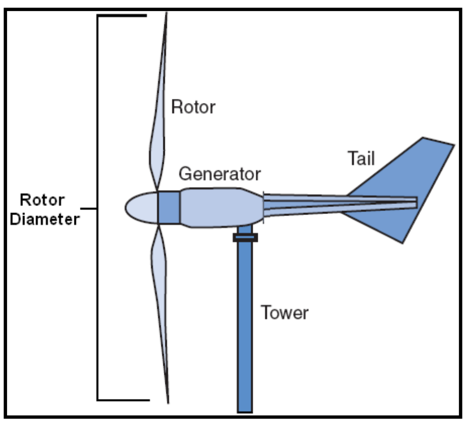


Figure 4.2: Horizontal axis wind turbine (HAWT)

Once a site with ample wind is selected, two prominent turbine technologies are available to take advantage of the location's unique characteristics. These two types are and vertical axis wind turbine (VAWTs). A HAWT (Figure 4.2) is the most successful and widely used type of turbine. They produce power more efficiently, but also require a tower and more complex installation procedures than other technologies. Towers are engineered for a particular turbine and must account for vibration, forces, deflection, blade clearance, land conditions, and obstructions. There are two common types of towers: monopole and guyed (Figure 4.3). Monopole

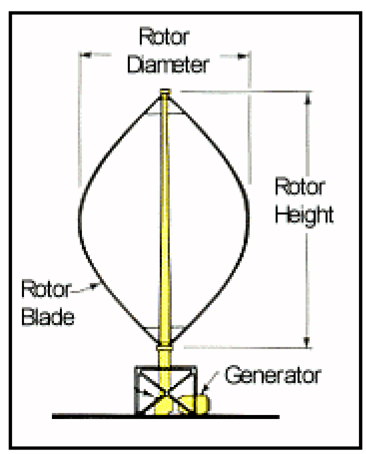


Figure 4.3: Horizontal axis wind turbine (HAWT)

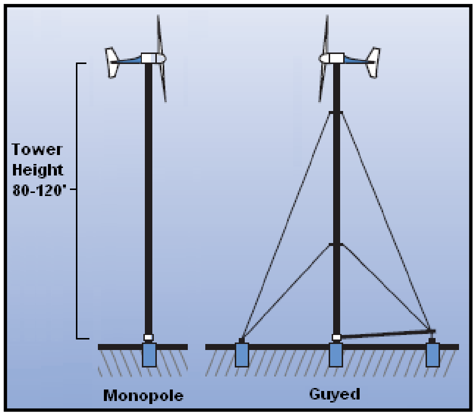


Figure 4.4: Vertical axis wind turbine (VAWT)

towers are those typically seen on large turbines, they have a smaller footprint but are more expensive[46]. Guyed towers are held upright by guy wires that extend some 30 feet from the base of the tower.

Towers should be between 80 and 120 feet in height to optimize wind energy potential. Since wind speed increases with height above the ground[46], small investments in tower height can yield high rates of return in power. In other words, installing a turbine on a short tower is like putting solar panels in shade.

VAWTs (Figure 4.4) can utilize wind from any direction, but are on average 40% less efficient than HAWTs [50]. A VAWT is very difficult to mount on a tower so they are limited by functioning close to the ground where winds are slower and more turbulent. Another option is to affix the VAWT on top of a building, or other structure, but this typically causes problems with vibration. Another advantage of a VAWT is that operation and maintenance costs tend to be low due to decreased levels in system complexity[50].

Other newer technologies exist that are not yet commercially available, such as helix roof top turbines (Figure 4.5). These turbines are designed for an urban setting with average wind speeds of 10 mph, and are fixed on top of buildings or other structures. Helix turbines are noise and vibration free and have the ability to utilize multi-directional and gusting winds. Winds in cities are more dependent on drafts and building height rather than local wind trends so this makes site selection extremely important as each structure will have a unique wind footprint.

Figure 4.5: Helix roof top wind turbine

4.3 Physical Potential

The American Wind Energy Association (AWEA) has estimated that Rhode Island has, on average, 109 MW of small wind energy potential and an annual estimate of 1 billion kWh[44]. Sufficient wind is generally found along RI's coastlines, especially the Eastern bay area, and throughout Block Island (Figure 4.6).

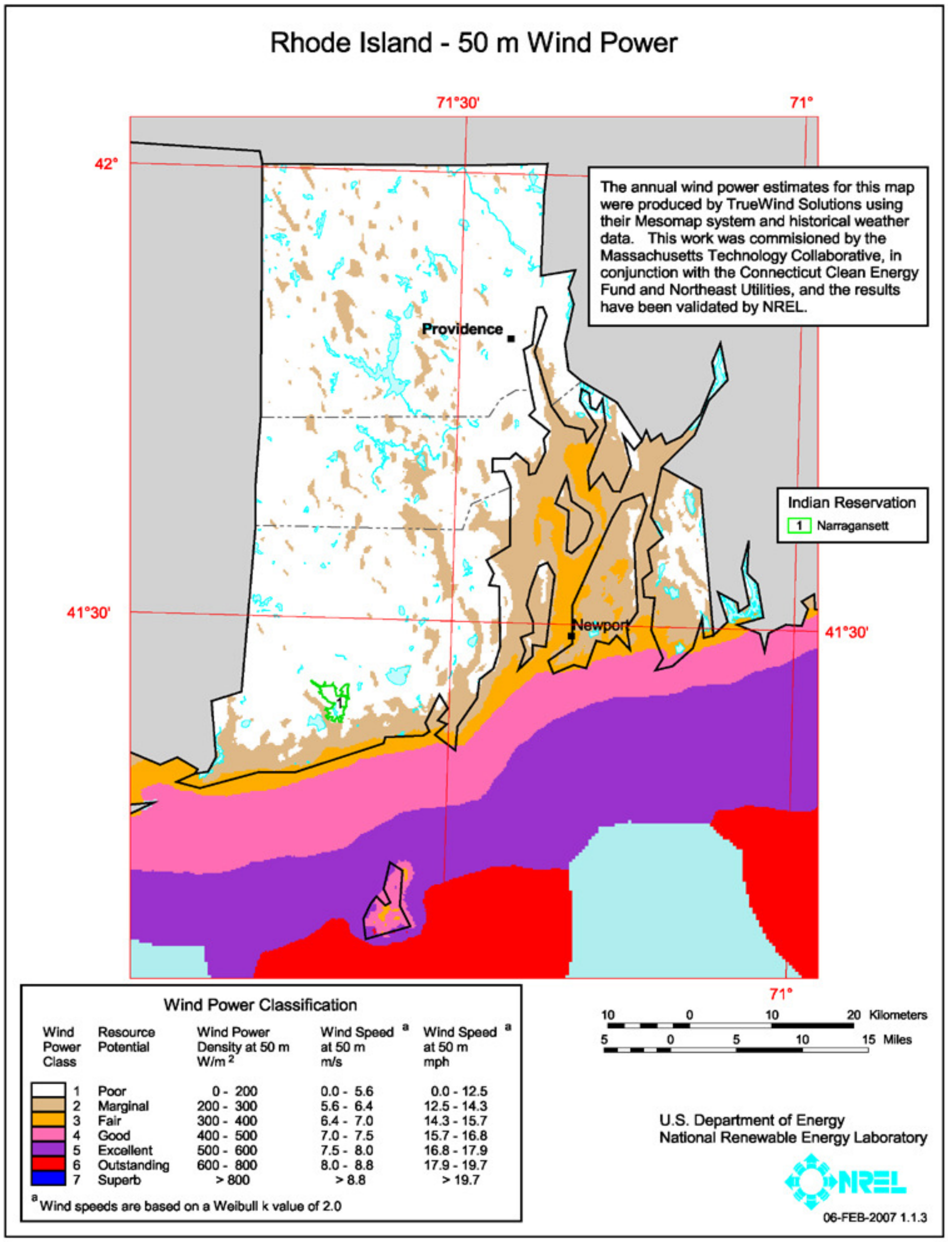


Figure 4.5: Rhode Island wind power classes at 50 meters

In general, for small wind to be physically and economically feasible, the site should have a wind power class of 2 or greater[46]. In Rhode Island, wind classes higher than 4 can only be found off-shore and are not applicable to small scale systems. Wind power classes are based on a range of wind power densities, measured in watts per square meter (W/m^2) (Table 4.1). Power densities are used to show power output relative to wind speed, but they cannot be used to estimate power output for a specific turbine[35]. Power density is based on the average wind speed and wind speeds can vary greatly depending on weather conditions and season. Winter is the season of maximum wind power throughout Rhode Island, and summer is the season of minimal wind. Because of these variations, a site having a high wind class will most likely have sufficient and more constant power output throughout the entire year.

Table 4.1: Standard Wind Class Definitions at 30m [59]

Class	Wind Speed m/s	Wind Power W/m^2
1	0-5.1	0-160
2	5.1-5.9	160-240
3	5.9-6.5	240-320
4	6.5-7.0	320-400
5	7.0-7.4	400-480
6	7.4-8.2	480-640
7	8.2-11	640-1600

Wind resource maps are most useful for identifying a site's power class, or finding other potential sites, but they are not accurate enough for turbine siting. Wind is influenced by many factors such as local topography, obstruction, surface roughness, temperature, and air density. So even within a relatively small piece of land, wind speeds can vary widely. Small-scale wind turbines are especially susceptible to these factors (Figure 4.7).

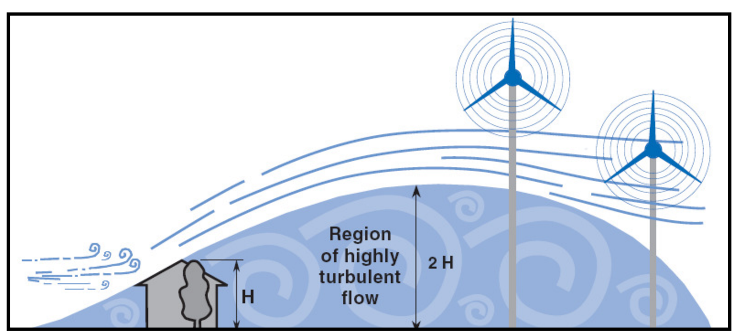


Figure 4.7: Air flow diagram

Direct monitoring by a wind resource measurement system (e.g. an anemometer) provides the most accurate wind data, but for most small wind systems the cost of year long measurements is not justified. However, since proper siting is critical to maximize turbine performance, an experienced installer should always be consulted before any investments are made.

4.4 Incentives

4.4.1 Rhode Island Incentives

In Rhode Island, several financial incentives exist for small-scale wind installations, including tax exemptions, tax credits, net-metering, and a grant program. Through the discretion of the city or town, a wind energy system may be exempt from property tax; however this program is not exercised consistently throughout the state (Appendix E: RI-5). Throughout all of Rhode Island residents and business owners receive 100 percent sales tax exemption on any new wind system parts sold by the manufacturer (Appendix E: RI-7). Eligible wind systems, that meet specified qualifications, can also receive a tax credit of 25 percent the cost of the system, up to a $15,000 total system cost (Appendix E: RI-1). Net-metering offers credits to customers for their excess energy generation with a maximum capacity of 25 kW (Appendix E: RI-12). Through the renewable energy fund, a grant of $2 per watt, up to 10 kW, is available for small scale wind (Appendix E: RI-16). In order to receive this incentive a comprehensive schematic and obstruction analysis is required. This component is lacking in other incentives. However, the fund has only allotted $50,000 for wind which will, most likely, be quickly exhausted.

Residential wind turbine in Jamestown installed in 1975.

Rhode Island also has two market incentives for wind, including a short term contract for renewable energy certificate (REC) sales and a rebate for REC purchases. Owners of a wind system can sell their surplus energy as RECs. People's Power and Light, which is a non-profit organization, offers a short term, 3 year contract of $30 per megawatt-hour or $0.03 per kilowatt-hour (Appendix E: RI-4). These RECs can then be purchased by energy consumers who wish to support the development of renewables. The small customer incentive program (Appendix E: RI-2), was a temporary incentive offered until its expiration on June 30, 2008. A one-time rebate of $125 on REC purchases was awarded to the first 6,000 customers state wide, and $75 thereafter. For RECs purchased through National Grid, the rebate was lessened to $75. In total, the fund had $1.6 million to support enrollment of 15,000 customers. Information on how much of these funds were allocated during the programs duration is not readily available.

4.4.2 Incentives in Other Jurisdictions

Many of New York's incentive programs are administered by a separate entity known as New York State Energy Research and Development Authority (NYSERDA). NYSERDA has a competitive research grant program (Appendix E: NY-4) that focuses on technology development as opposed to individual installation systems. NYSERDA identified a total of 29 wind system models made by 12 different manufacturers, ranging from 800 W to 250 kW, as being eligible for an incentive (Appendix E: NY-16). Each model is granted a different level of incentive based on energy output and efficiency. If the market for wind develops, this could be an excellent option

Portsmouth Abbey wind turbine.

for Rhode Island to allocate funds; however, due to the current lack of vendors and manufacturers wind system models would be severely limited.

A property tax exemption (Appendix E: NY-7) is an incentive that New York uses that is similar to Rhode Island except that exemption is mandated across the entire state whereas Rhode Island allows cities and towns decide if they want to adopt the incentive. Having a mandated incentive would ensure that the property owner bears no additional property taxes from a wind system which can add significantly to the turn-key cost. New York also has a loan program (Appendix E: NY-11) for up to 100 percent of the system cost in fixed terms up to 10 years. Rhode Island could model and improve upon some of the loan programs that exist in New England.

Massachusetts has a variety of incentives that are similar to Rhode Island's including tax exemptions, grants, and net metering. They do however have a few incentives not present in RI that could greatly improve market development. MA's business expansion incentive (Appendix E: MA-9) is a loan program to support renewable energy companies that currently, or plan to, manufacture renewable energy technology products. The program can provide up to 50 percent of the capital expenses and related spending over a 24-month window. This type of program would be extremely beneficial to RI to help create a market for wind and give customers a local option for purchasing wind systems. Permitting in RI can drastically slow the process of installation and there are many issues involved that towns have never addressed before. MA provides a special permit for construction and operation of wind facilities while providing standards for placement, design, construction, monitoring, modification and removal (Appendix E: MA-27).

Connecticut has noteworthy programs to bring in awareness and information on small-wind systems. One program which has been highly successful is CT's community grant program (Appendix E: CT-6), which provides eligible communities with a $5,000 block grant to support local public awareness and education projects that promote renewable energy. A program like this in RI would help correct some of the misconceptions the public has about the feasibility of a wind system. Two programs that can help wind market development are an operation and demonstration program (Appendix E: CT-4) and wind contractor licensing and training (Appendix E: CT-14). One offers industry support and recruitment so as jobs become available there will be sufficient qualified workers. This is also coupled with a contractor licensing and training to ensure that turbine installers are well-informed of current laws and provide a base of local knowledge. Together these exemplary incentives work to build infrastructure and stimulate markets so that non-utility scale renewables are feasible and beneficial to the state's economy.

4.5 Analysis

4.5.1 Energy Output at Incremental Tower Heights

For this report, annual energy outputs (kWh/year) at three tower heights were calculated using the Bergey Excel 10kW power calculator[60]. The calculator estimates power based on specified parameters. The calculator was set to represent conditions typical of a coastal site in Rhode Island. Values used include a 10 percent turbulence factor, 61m mean elevation, a Weibull distribution of k=3, and a 30m anemometer height (these variable are more fully described in Appendix B). Power output was determined using the upper limits of the first four standard wind classes at 30m anemometer height (Table 4.1). The calculator automatically adjusts for differences in anemometer and tower height. As seen in Table 4.2, energy output increases with wind speed.

Table 4.2: Annual energy output at incremental tower heights and wind speeds

Tower Height	60' (18m)	80' (24m)	100' (30m)
Wind Class	**Power Output (kWh)**		
1	7,864	8,998	9,956
2	12,406	13,971	15,278
3	16,307	18,194	19,753
4	19,806	21,935	23,668

4.5.2 Capital Cost

System costs can vary greatly depending on tower height, market price, system site, and system type. In Table 4.3 costs for a 10kW system and its components can be seen for varying tower heights. Values assume that all of the labor is contracted out. A guyed tower was chosen as the most cost-effective tower to purchase and install[44]. In Rhode Island, there is 100 percent sales tax exemption on all new parts of a wind system bought from the manufacturer (RI-7), so tax was not included in these projections. Turbine costs were compared with costs projected in other sources and they were within a range of $5,000[2]. Other costs could also be incurred that are not quantified here, defining the total turn-key cost. These could include permitting and any special installation requirements based on site conditions.

Table 4.3: System component costs ($) for a 10kW wind system at varying tower heights [44]

Tower Height	60' (18m)	80' (24m)	100' (30m)
Foundation[1]	2,510	2,510	2,510
Turbine and Inverter[2]	25,550	25,550	25,550
Tower[3]	9,100	9,910	11,130
Electrical[1]	3,000	3,000	3,000
Installation	5,750	6,050	6,250
Capital Cost ($)	45,910	47,020	48,440

1. Includes materials and labor
2. Includes shipping
3. Includes shipping and wiring

4.5.3 Energy Output vs. Capital Cost

As shown in Table 4.2, the two largest influences on power output are wind speed and tower height. Intuitively, higher wind speeds are going to yield higher energy outputs, and one way to achieve higher wind speeds is by increasing tower height. Increasing tower height will increase capital costs due to increased materials and labor.

Extra costs are then offset by increased power output. In Table 4.4 it can be seen that the incremental energy output from a taller tower is higher than the incremental cost.

Table 4.4: Incremental costs vs. incremental energy output at varying tower heights

Tower Height	kWh/year*	Capital Cost	Incremental Cost from 60'	Incremental Energy Output from 60'
60' (18m)	12,406	$45,910	---	--
80' (24m)	13,971	$47,020	2.4percent	12.6percent
100' (30m)	15,278	$48,440	5.5percent	23.1percent

*Assumes Class 2 wind speeds at 30m anemometer height, which is the minimum wind speed recommended by the AWEA for a small scale turbine.

4.5.4 Cost Benefit Analysis- Report

The goal of this analysis is to present a method for producing cost-effective energy from small scale wind systems. The first component of the analysis was to quantify all costs and benefits possible including capital costs, O & M costs, avoided fuel costs and immediate benefits (refer to Appendix B for further explanation). The second component was to compare the systems total NPV across different wind speed classes. It should be noted that cost benefit projections for wind projects will fluctuate based on turn-key cost, variability in energy price, O & M costs, and site conditions.

An average capital cost of $47,123 was used from prices calculated for varying tower heights (Table 4.3). O & M costs range between 1-2 percent of the original turbine investment and are relative to turbine size and energy output because the turbine is subject to more wear and tear with increased use. An O & M cost of $0.015/kWh was used for this analysis based on previous studies of small scale turbines[12]. Other maintenance costs could be encountered if any serious damage is incurred by the system.

4.5.5 Results

As seen within Table 4.5 the NPV of the system increases with increasing wind speed. Higher wind speeds yield higher energy outputs, which equate to additional avoided fuel costs adding to the total benefits. A system becomes cost effective when its NPV is greater than zero, and as illustrated in Figure 4.8 this system is only cost effective within wind speed class four. If the total cost of the system could be lowered, then the system would be cost effective at lower wind speed classes. This serves to demonstrate the importance of turbine siting and wind resources to cost-effectiveness. Unless costs are dramatically lowered, it will not be cost-effective to put a turbine in an area with a low wind speed class.

Table 4.5: Cost Benefit Analysis of 10kW system over Wind Speed Classes 1-4*

Wind Speed Class	1	2	3	4
Total Tangible Costs	$48,685.63	$49,550.15	$50,284.27	$50,934.25
Total Tangible Benefits	$21,835.98	$33,917.96	$44,176.81	$53,259.87
NPV	-$26,849.65	-$15,632.19	-$6,107.46	$2,325.62

*Full table in Appendix

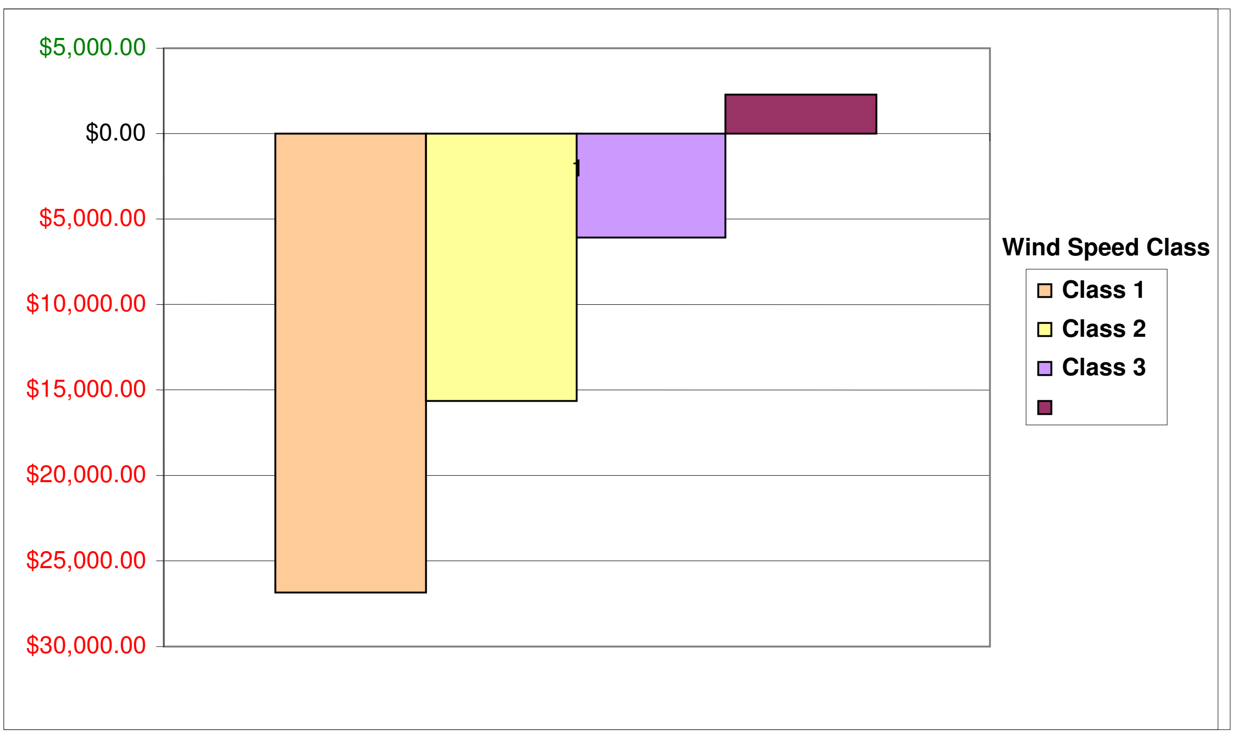


Figure 4.8: Cost-Benefit Analysis: Small-scale Wind Power (10kW)

4.6 Conclusions and Recommendations

Thus far it has been show that there are cost-effective sites in Rhode Island for wind. RI currently has a respectable set of incentives for wind. However, they lack the connectivity and viable access necessary for any evident change to be seen. The next step is then to ensure that the financial and informative assistance, along with the organizational infrastructure exists to truly advance small-scale wind development and achieve the full potential of RI's wind resources. Accordingly, the following are suggested:

(1) Priority should be given to sites with the highest wind classes (3-4) where towers of eighty to one hundred feet can be accommodated. Wind turbines in areas with low wind speeds (less than class 2) are not cost-effective given existing technology and state incentive programs should preclude funding such projects.

(2) Establish an information sharing and education system: Ensure that Rhode Islanders can learn their options for their property. After which, they can then become educated and possibly certified on the economic and technical components of the system they wish to install.

(3) For sites that may not be initially cost effective (with at least class 2), reduce capital burdens to a reasonable extent with the purpose of realizing a net benefit to the user, which could be done separately or in conjunction with system reliability and least cost procurement.

(4) Establish low or zero interest loans for systems that are initially cost effective (class 3-4 winds).

(5) Reduce complexity and risk for projects by having pre-set standards for siting and system requirements. Ensure ahead of time that turbines will be cost effective and funds are properly allocated.

(6) Advance market conditions that facilitate wind system installations and suppliers. Creating a market for wind installation in RI would help keep resources in the local economy and assist in creating renewable energy infrastructure.

5 HYDROELECTRICITY

5.1 Introduction

Rhode Island has 674 dams with a total of 11.5MW potential hydroelectric power. Few incentives exist to take advantage of this potential. Rhode Island should draw upon on incentives used in other states to maximize the benefits of hydropower. In particular, three areas need to be addressed: repair of high hazard dams, mill refurbishment and public education.

5.2 Background

Rhode Island has put trust and confidence in hydropower since the 1600s. In fact, Rhode Island's Pawtucket Falls on the Blackstone River powered first textile mill in America.[26] The major shift in the State's economy to cotton manufacturing during the early 1800s required the use of most rivers in the state for power. As Rhode Island's economy grew, electrical demand shifted from hydropower to sources such as steam and electricity.[39] There are currently 674 dams in the state of Rhode Island, many of which were used for hydropower in the past. The Department of Environmental Management (RIDEM) classifies 31percent of dams in the state as hazardous.[41] Dams in need of repair and mills in need of rejuvenation are visible throughout the state. Small-scale hydroelectric development addresses these challenges with additional benefits in the form of renewable power.

Pawtucket's historic Bridge Mill power plant, built in 1894.

Hydroelectricity has historically been a reliable and efficient source of energy. Unlike other forms of renewables, hydropower technology has been thoroughly developed and proven as an effective energy source over many generations. The U.S. derives about nine percent of its electricity from hydropower, which is mostly produced at large-scale facilities.[23] Such large-scale facilities are efficient energy producers but may have adverse impacts on water systems and fish populations. Many states, including Rhode Island, have renewable energy standards that exclude large-scale projects entirely. However, since only small-scale potential exists in Rhode Island, all hydropower development in the state is considered renewable. Small-scale hydroelectric projects offer a promising alternative by negating major environmental impacts while providing a continuously renewable source of energy.[32] This chapter examines potential for small-scale hydroelectricity development in the state of Rhode Island. Results from previous studies will be coupled with current and potential incentives to determine the best methods for utilizing hydropower within the state.

Historic mills at Gilbert Stuart's birth place in Saunderstown.

5.3 Technology

Small-scale hydro is often developed using existing dams, or run-of-the-river technology, which can greatly minimize environmental impacts. No new flooding is necessary if existing dams are used. Run-of-the-river implies no or minimal storage reservoir. Instead, water flowing through the turbine is virtually identical to pre-development flow rates. Power is generated directly from the moving water, rather than from water falling from a reservoir through a penstock and into a powerhouse. Run-of-the-river facilities lessen effects to fish passage, watersheds, and water quality, but usually reduce total output.[28]

Hydroelectric technology is extremely efficient at 60-85 percent capacity on average and it is not unusual for a hydro facility to reach 90 percent capacity.[49] Therefore, the output is about 90 percent of maximum potential, making it the most efficient of energy conversion technologies.[59] Output from hydropower depends on the head and flow rate of each site.[32] More water moving through the turbine will produce more power, therefore power is directly proportional to flow rate. Every proposed site has different attributes, and each facility is custom-built to maximize potential output, which results in highly efficient energy production.

Although the majority of hydroelectric systems are site specific, some general components are necessary in every small-scale hydro system: penstock, turbine, generator and regulator (Figure 5.1).[28]

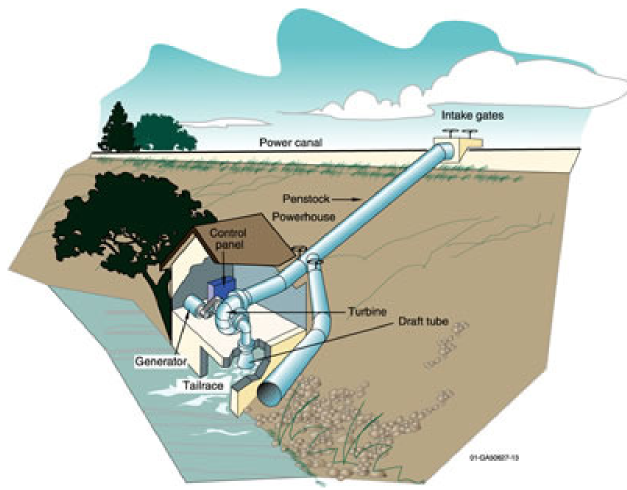


Figure 5.1: Illustration of a microhydro facility taken from the Energy Efficiency and Renewable Energy website within the US Department of Energy.[61]

5.4 Physical Potential

Rhode Island, with its distinct coastal topography, has the potential to supply about 11.5 Megawatts (MW) of hydroelectricity. The state's features include coastal plains around Narragansett Bay and in the southeast in addition to rolling hills in the west and northwest. Overall, the elevations vary from about 800 feet to sea level, with Rhode Island's lowest elevation at the Atlantic Ocean and Narragansett Bay. The highest natural elevation in the state is Jerimoth Hill at 812 feet above sea level. The largest lake in Rhode Island is the Situate Reservoir.

The major rivers that traverse Rhode Island are the Blackstone, Pawtuxet and Pawcatuck rivers. The Blackstone River, located in Providence County, flows into northern Rhode Island from Massachusetts and southward to the head of Narragansett Bay.[26] The average annual flow of the Blackstone River is 862 cubic feet per second (cfs). The Pawtuxet River, located in central Rhode Island, is the largest watershed within state. The river flows from west to east, with its headwaters in the hills of western Rhode Island. In the neighboring watershed, to the south, the Pawcatuck River stretches approximately 23 miles north to south and flows 20 miles east to west and north to south. It discharges an average of 675cfs of freshwater into the estuary that creates a natural border between Rhode Island and Connecticut. [11]

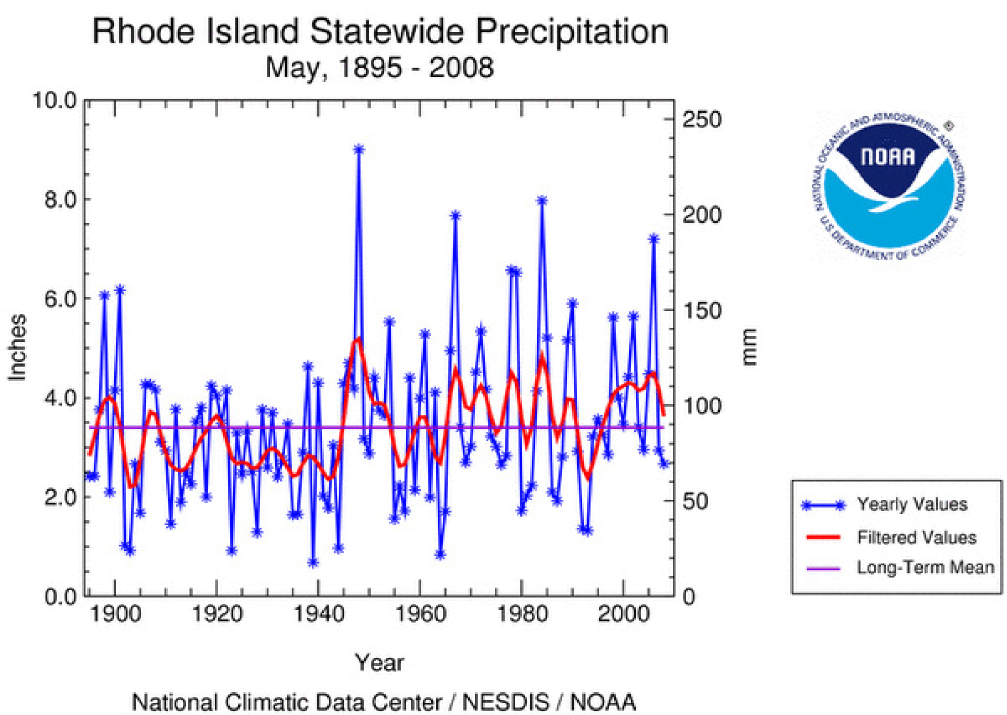


Figure 5.2: This graph shows the statewide precipitation for the past century. Rhode Island has a long term mean of about 3.8 inches annually with some extreme variations.[7]

Rhode Island's average annual precipitation is 46.45 inches, including approximately 39.2 inches of snowfall. Throughout the year, moisture levels remain consistent, ranging from about three inches of precipitation during the summer months to as high as 4.43 inches of precipitation during the spring months.[7]

The hydropower potential of Rhode Island's rivers has been estimated by the Idaho National Engineering Laboratory.[56] Each dam site has an estimation of its hydropower potential, and where it is located. Throughout the state, 45 dams have between 0.02-0.04 MW of hydropower potential, which equates to about 1.02 MW total. On a larger scale, there are only four dams with hydropower potential higher than 0.6 MW.[53] Although there are fewer potential sites with higher power potential, a total of approximately 2.8 MW is still accessible through these sites (Figure 5.3). While only small scale projects are recognized under Rhode Island's Renewable Energy Standard, the legislation defines "small scale" hydro as 30 MW of potential power, although 10-15 MW is becoming the generally accepted standard.[59]

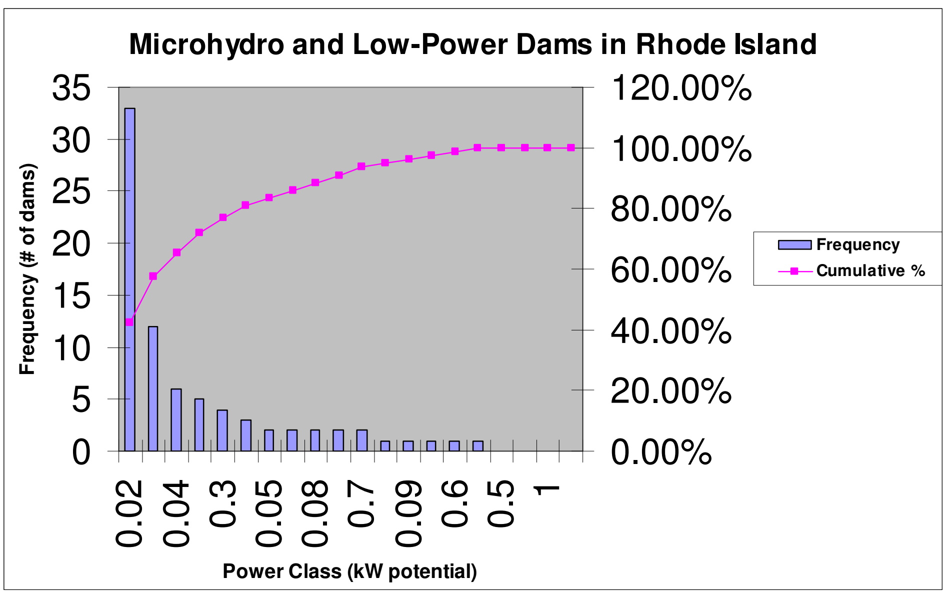


Figure 5.3: The kilowatt potential for microhydro and low-power dams in Rhode Island distributed according to power class demonstrates that the majority of these dams have low energy potential. Although there are fewer high energy producing sites, their potential is almost three megawatts of electricity.

5.5 Incentives

5.5.1 Rhode Island Incentives

A 1995 study prepared for the US Department of Energy estimated that there is a total of 11.5 MW of undeveloped hydropower at sites with pre-existing dams in Rhode

Island.[56] The vast majority of the sites reported by the INEL, are capable of producing <1 MW of electricity and none have greater than 5 MW potential. The only current incentive to take advantage of this hydropower potential in Rhode Island is a low interest loan through the RI Renewable Energy Fund established in 2006. This loan program is being used to fund two small scale hydropower feasibility studies and one installation.[36]

5.5.2 Incentives in Other Jurisdictions

Several of Rhode Island's neighboring states have adopted incentives which could serve as valuable models to Rhode Island. The funds vary over application, technology, and installation costs depending on the state.

The on-site renewable programs found in Connecticut and Massachusetts provides direct monetary incentives to a variety of sectors who utilize power generated from on-site projects.[9] In Massachusetts, two on-site initiatives exist to take advantage of renewable energy potential. The Large Onsite Renewables Initiative (LORI) Grants (MA 14, MA-18) consist of two parts: a feasibility study grant, and a design and construction grant. Qualifying projects must be larger than 10 kilowatts (kW). The Small Renewables Initiative (SRI) Rebates promote small scale projects. Both Massachusetts incentives allow retrofits for hydroelectricity projects. Joint ventures such as dam repair and mill refurbishment along with hydropower development qualify under these incentives to subsidize costs.

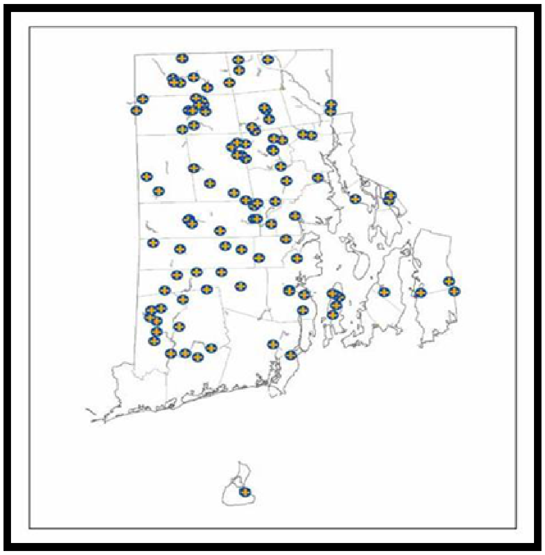
Connecticut offers grants for the installation of customer-side distributed resources.[9] This incentive only applies to baseload projects that demonstrate a reduction in the demand for electricity on the site of a retail end user in the distribution system. Hydroelectric systems are typically baseload generators because they continuously generate power. Connecticut awards $450/kW for the installation of baseload renewable projects, which is complemented with the characteristics needed for hydropower development.

Delaware uses a non-traditional incentive to promote renewable energy through demonstration of a new technology or the new application of a technology. The Technology Demonstration Program (TDP) provides grants to projects that demonstrate the market potential for renewable technologies and accelerate the commercialization of these technologies within the state.[10] The grant covers 25percent of the cost of the eligible equipment for a renewable energy technology project, but no more than $200,000 per project. Hydroelectric projects placed at existing dams or in free-flowing waterways may be eligible for a grant under this program. The TDP offers a marketing opportunity for the company installing the technology, and raises public awareness about commercially available, non-utility scale renewable energy opportunities.

5.6 Integrated Policy Objectives

5.6.1 Dam Repair

Of Rhode Island's 674 dams, 14percent are classified as high hazard, and 17percent are classified as significant hazard (see Figure 4).[41] The Department of Environmental Management (DEM) classifies a "high hazard dam" as a dam where failure or misoperation will result in a probable loss of human life. These dams have required visual inspections every two years. "Significant hazard dam" indicates a dam where failure or misoperation results in no probable loss of human life, but can cause major economic loss, disruption of lifeline facilities, or cause other concerns detrimental to the public's health, safety or welfare. Examples of major economic loss include but are not limited to washout of roads, impaired emergency access to residences, or damage to a few structures. These dams have required visual inspections every 5 years. Hazardous dams are required under Rhode Island statute to be "properly operated, maintained, repaired or removed" to protect public safety, private property, drinking water, recreation and scenic beauty.[37] The statute suggests that local communities form dam management districts as a financial tool to meet high costs. This particular law was written so that hydroelectricity could be incorporated in repairing hazardous dams.[33] Community scale hydropower coupled with dam improvement will lessen burden of initial costs while ensuring public safety in Rhode Island.



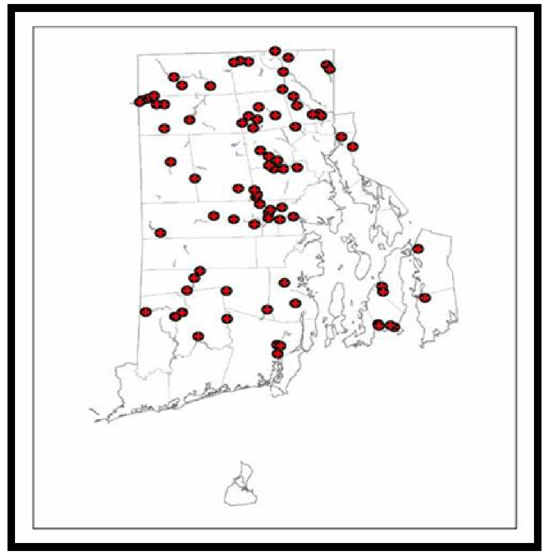


Figure 5.5. Maps of hazardous dams as designated by RI DEM in 2007. The left image shows "high hazard" dams, while the image on the right is of "significant hazard dams" in Rhode Island.[41]

5.6.2 Mill Refurbishment

Most historic mills in New England are no longer being used for their original purposes. Many are being renovated into modern offices or residential units. Installing small-scale hydroelectric systems on these properties is a feasible and cost-effective way to combine renewable energy with development. For example, a potential mill redevelopment project, proposed by Struever Bros. Eccles and Rouse (SBER) in West Warwick, would create a new residential community that uses its own natural resource, the Pawtuxet River, as a source of energy. SBER has transformed the Royal Mills Complex from an old textile mill into an apartment complex. The project includes installation of a $1.7-million hydropower system that will power the community and common area spaces of the

Royal Mills on the Pawtuxet River located in West Warwick.

500,000 square-foot complex.[8]

The restored project would use the pre-existing hydropower system components from the past textile proprietor. The 21-foot-high granite dam and 3.8 acre reservoir are pre-established as well as the power canal and powerhouse. The system has the capacity to produce 225 kW and is estimated to produce an average of 1 million kilowatt hours (kWh) annually.[55]

Royal Mills dam – site of proposed 225 kW hydropower system.

5.6.3 Public Education

Hydropower facilities can provide informal public education opportunities in at museums and outreach centers. For example, the Amoskeag Fishways Learning and Visitors Center is an environmental education center located in Manchester, NH on the Merrimack River. This hydropower facility includes a fish ladder which allows native fish populations to swim over the dam. The museum at the site is open to the public and school field trips are conducted on a regular basis. Educational topics include river wildlife, river ecology, electricity, hydro and solar power, fish biology and, urban wildlife. NH derives 5 percent of its electricity from hydropower and this facility serves as a powerful symbol of the benefits of clean energy in protecting environmental resources.[58]

Fish ladder at Rising Sun Mills dam located in Providence.

The historic Slater Mill in Pawtucket, Rhode Island has an initiative to restore their existing turbines to generate electricity and provide educational opportunities for visitors. A grant from Housing and Urban development has allowed to the museum to begin planning to restore the two turbines found underneath the mill. The energy created from the turbines will power the museum as well as the blacksmith shop. Educational program topics will include physics, hydropower, ecology, energy transfer and sustainability.[50] By continuing to develop educational programs around hydropower facilities, Rhode Island could provide community education while promoting hydroelectric development.

Slater Mill dam located in Pawtucket.

5.7 Regulations and Codes

Non-utility small-scale hydroelectric customers in Rhode Island face several regulatory obstacles prior to development. Because dams influence fresh water systems, the Freshwater Wetlands Act requirements must be followed.[38] The regulations which implement the Act stipulate that maintenance of approved or existing structures, like a pre-existing dam, cannot increase vertically or horizontally in physical size (section 6.03 p. 19). This means that during a joint venture between dam repair and small-scale hydro, the dam may not be increased in size to accommodate the new purpose. This section also states that the RI DEM must receive written notification at least 10 days prior to inspection, maintenance, or repair of a dam. The letter must include estimated time of completion and all anticipated activities. Also during dam repair, water level must not be lowered more than absolutely necessary to complete pre-approved projects. Cofferdams can be used if needed. A cofferdam is a temporary enclosure beneath the water that allows water to be displaced by air to create a dry work environment for activities such as dam work.

Section 6.10 of the regulations implementing the Freshwater Wetlands Act relate to construction of utility lines. New utility lines may only be constructed on, above, or beneath existing or pre-approved roads, railroads, or shoulders. For small-scale hydro,

Horseshoe dam located in Richmond.

Section 6.10 requires that if a dam is located in a remote location, special permits must be received by RIDEM to construct transmission lines. Section 6.19 of the regulations specifically addresses the issue of repairing dams labeled as high or significant hazards. Maintenance and repair of these dams is permissible, provided that the project does not require significant alterations, and projects must follow the RI DEM's Dam Safety Rules. Alterations to low hazard dams or significant alterations to high or significant hazard dams have mandatory application and permit fees which vary with the size of each project.

5.8 Analysis

Two tests were used to determine the economic feasibility of installing a small-scale hydroelectric project. A cost-benefit analysis from the perspective of the end-user was performed for a variety of power potentials, system costs, and technological efficiencies. A cost-effectiveness analysis was used to determine the best scenario for concurrently installing hydropower while repairing hazardous dams.

5.8.1 End-User Cost-Benefit Analysis (CBA)

Four different power capacities were chosen from real sites in Rhode Island at 29 kW, 57 kW, 106 kW and 58 kW. Capital costs vary greatly based on sites from $2,000/kW to $8,500/kW. Annual operation and maintenance costs vary based on different efficiencies of the power system. Results show positive benefit-cost ratios for all four power scenarios in a range of capital costs, and in a range of efficiencies. For example, at 29 kW capital costs range from $58,000 to $246,500. Annual costs total $28,938 at 85percent efficiency and $20,427 at 60percent efficiency for the lifespan of the system. Tangible benefits from avoided fuel costs range from $372,000 to $528,000 depending on efficiency. Net present values (NPV) of the 29 kW system range from $105,410 to $440,539, and benefit cost ratios range from 1.39 to 6.06. NPVs increase steadily for larger systems, but the cost-benefit ratios remain constant.

5.8.2 Cost-Effectiveness Analysis (CEA)

Two alternatives were suggested through the CEA to find the least-cost scenario: 1) dam repair, and 2) dam repair with hydroelectric installation. The same four sites described in the CBA were also used in the CEA. Total dam repair costs include reconstruction costs and inspection fees which range from $635,250 to $818,338. Dam repair costs with hydropower include an application to alter a wetland fee, system costs, operation and maintenance over a 25 year life expectancy, plus dam repair costs (Figure 5.6). Tangible benefits are avoided fuel costs over the life expectancy of the system. Projected net benefits for the 106 kW and 658 kW will repay both dam repair costs and costs of the hydropower system, while earning a substantial amount of money. Costs for the 29 kW and 57 kW systems are much lower than if hydropower was not included, yet they do not entirely pay for the costs of dam repair and hydropower systems.

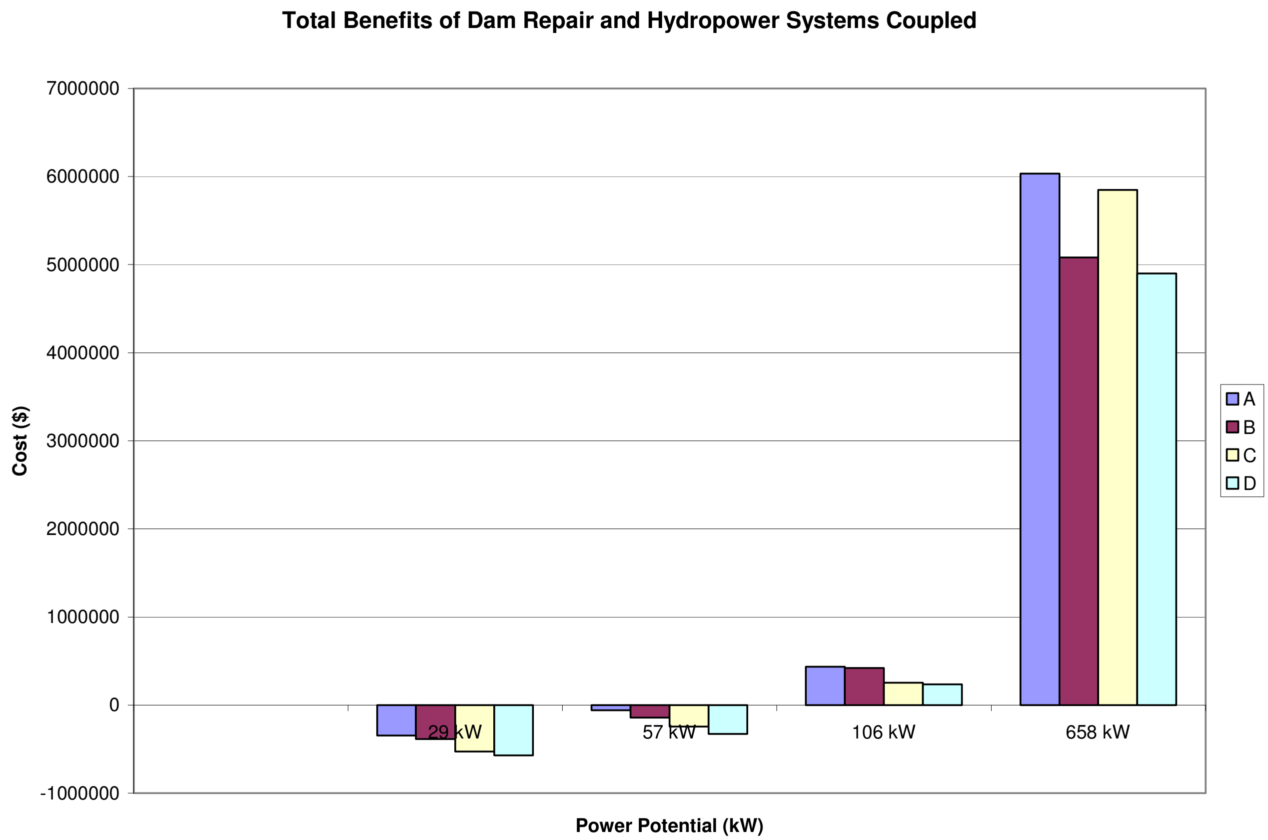


Figure 5.6 : The total benefit of coupling dam repair and the installation of hydropower at high hazard and significantly hazardous dams. As seen in the figure, the most financially beneficial projects are located at the two potential sites (106kW and 658kW).

A	Low Benefits, Low Dam Repair, Low Capital Costs
B	High Benefits, Low Dam Repair, High Capital Costs
C	Low Benefits, High Dam Repair, Low Capital Costs
D	High Benefits, High Dam Repair, High Capital Costs

5.9 Conclusions and Recommendations

Without sufficient incentives or support for non-utility energy, initial high capital costs associated with small-scale hydropower are a financial burden to individuals. Capital cost recovery is associated with output, which is dependent upon head and flow of each site. Due to the topography of Rhode Island, most potential sites have a low head which greatly increases initial costs.[31]

Small-scale hydroelectric development in the state of Rhode Island is economically feasible under many different scenarios. All calculations in four potential sites produced positive cost-benefit ratios. Total estimated potential is not substantial, however 11.5MW of clean cost-effective power should not be overlooked. Capital costs including equipment, permitting, installation, and civil works are the major deterrents to hydroelectric development. Microhydro potential is the most frequently estimated potential, but capital costs per kW are much higher than larger systems.

Because investments are fully recovered in all calculations, low interest loans are an optimal solution. Annual loan payment should be based on the distribution of capital costs with the amount of annual savings from energy reduction. Baseload incentive programs are also appropriate for hydropower. Connecticut's grant program for installation is a potential model for Rhode Island to follow.

Of the 674 dams in Rhode Island, 31percent are classified as hazardous. The state does not offer financial assistance to owners of hazardous dams because total costs would be overwhelming. Also, due to the high costs of dam repair, loans for repairs on high hazard dams are difficult for dam owners to repay.[41] If hydroelectric systems are installed during dam repair, net costs are significantly lower. Any hydropower system above 100 kW will have a lifetime net gain over a range of possible dam repair costs, system efficiencies, and system costs. Dam repair will still produce a net loss for hydropower systems under 100 kW, but net repair costs are notably lower with installed hydropower systems than solely dam repair. Installation of small-scale hydro at hazardous dam sites will increase income and offset expenses, while addressing dam compliance and safety. To decrease costs and aid in determining project feasibility, a grant program should be developed to abate permitting costs for projects coupled with high hazard or significantly hazardous dams.

A highly recommended action is to install visible projects as a multi-faceted approach to begin lessening developmental barriers. Dam repair, mill refurbishment, public education, and technological demonstration should be incorporated with hydropower projects as early as possible.

6 GEOTHERMAL

6.1 Background

Geothermal technology has been available for several decades. As with other renewable energy technologies, rising energy costs and environmental concerns have stimulated a renewed interest in it. In recent years, the U.S. Department of Energy along with the Environmental Protection Agency (EPA) have partnered with industry to promote the use of geothermal heat pumps [19]. There are estimated to be approximately 500 installations in Rhode Island.

6.2 Technology

Underground temperature varies less annually than above ground temperature, with the temperature below ground being cooler in the summer and warmer in the winter than air temperature. A geothermal heat pump (GHP), also known as a ground source heat pump (GSHP), takes advantage of this more constant year-round temperature to provide both heating and cooling in the winter and summer, respectively, by exchanging heat with the earth.

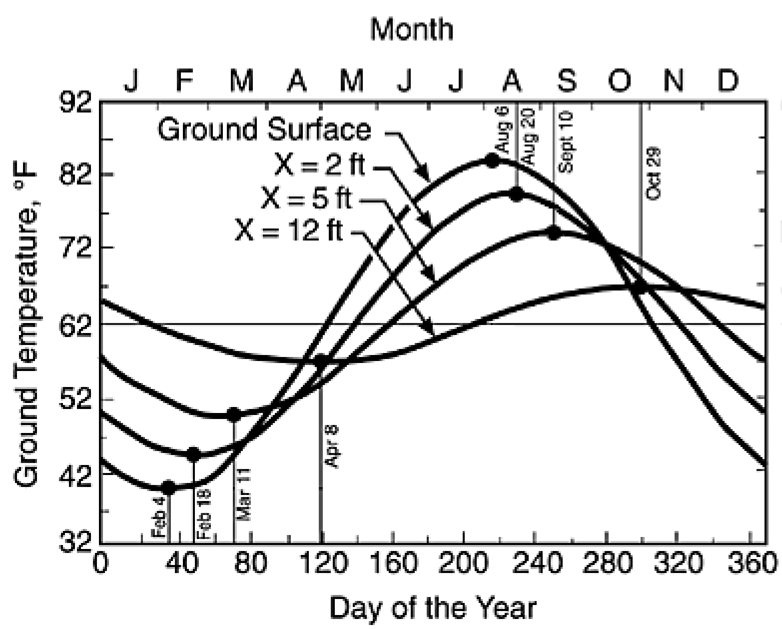


Figure 6.1: Annual Temperature Variation at Depths in VA[17]

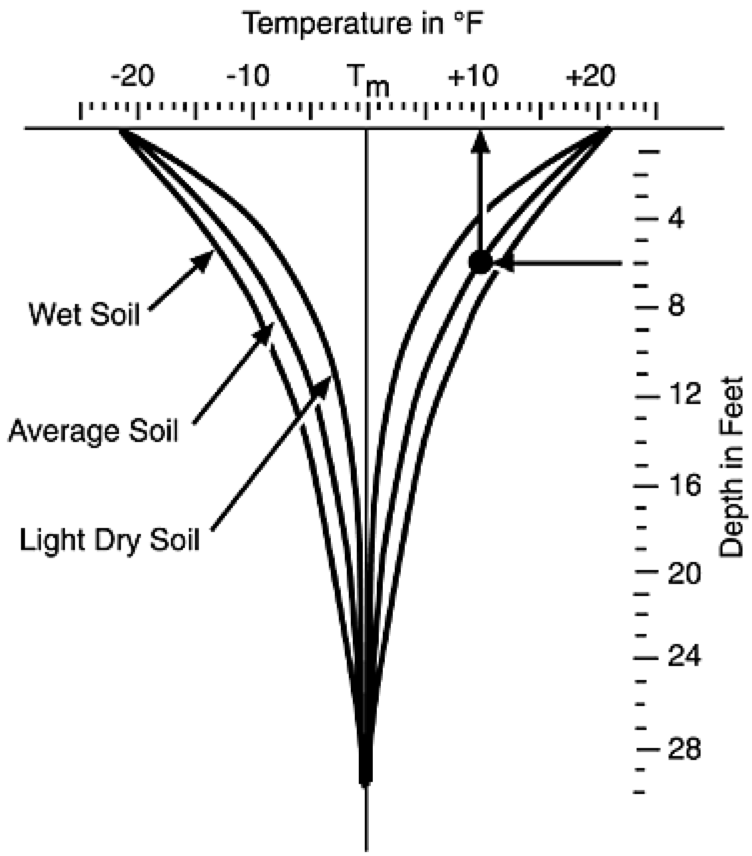


Figure 6.2: Mean Annual Temperature Range Versus Depth[17]

Geothermal Heat Pumps consist of a pump connected to a network of underground piping, through which a refrigerant—a fluid that transports the heat energy in the system—flows. Refrigerants are also known as "working fluids". The pump follows the same principles as a refrigerator, compressing and expanding a fluid to absorb and reject heat. During winter months the fluid is compressed underground to absorb heat from ground, then pumped up to the building and expanded to release heat. The opposite is done during summer months to cool the building.

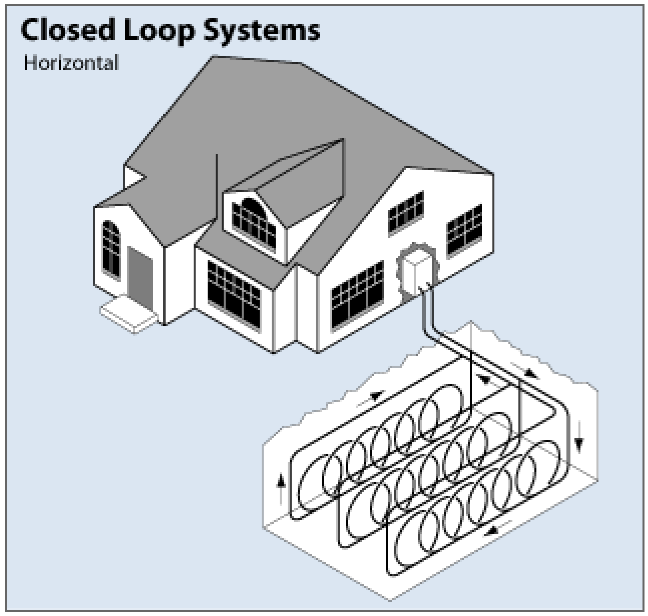


Figure 6.3: Horizontal Loop[20]

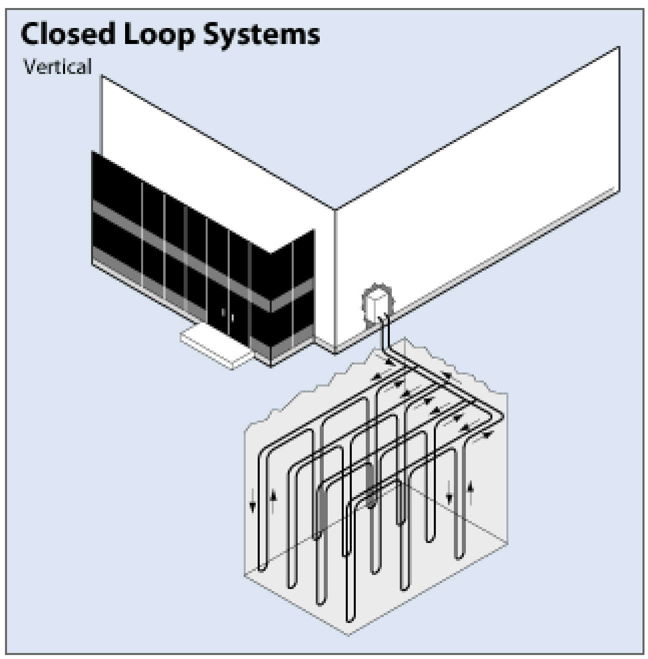


Figure 6.4: Vertical Loop[20]

Underground piping can be laid out horizontally or vertically, with advantages and disadvantages to each method. Horizontal pipes are cheaper to install, but vertical systems are more efficient at cooling and require less land. Underground piping can either run directly through the building or exchange heat with a separate system in the building's heat distribution piping. GHP systems installed at the same time as building construction typically share the same system, while retrofit projects typically have a system in the ground that connects to the piping system already present in the building.

If the net annual heat exchange between the pipe and its surroundings is not zero, (i.e. if annual average fluid temperature increases/decreases), an added source or sink can moderate the effect. Modified systems are usually called hybrid GHP (HGHP) or hybrid GSHP (HGSHP). The heat pump can also be used to provide hot water for the building by using a desuper heater (or desuperheater), which transfers excess heat from the heat pump's compressor to a hot water tank.

6.3 Physical Potential

The ability of geothermal power to function does not vary significantly spatially. With the exception of locations with bedrock near the surface and cities that do not have any space for digging, it is a nearly universally applicable technology. As a demonstration of the raw potential of geothermal heat pumps as a source of heating and cooling, consider the 1,949 new residential building permits granted in 2007. At the current average annual heating cost of $1,539 per household in RI, installing a GHP system in each of these new construction projects would save $3,000,000 the first year alone. Furthermore, this effect would compound itself, as each year's new construction would add to the annual savings, leading to $6,000,000 the second year, $9,000,000 the third, $12,000,000 the fourth, and so on. Note that this is only the savings from heating during the winter months. Adding in the energy savings from avoiding powering air conditioners in the summer would increase annual savings significantly. These savings also do not include the case of installing GHP systems in new non-residential buildings or in any type of renovation/replacement projects.

6.4 Analysis

The geothermal heat pump is a very promising technology that has shown itself to be an effective heating/cooling system in a variety of environments. However, simulation of the GHP potential of a region is nearly impossible due to the wide variability in system effectiveness. Because of this, a synthesis of case studies and practical knowledge (considering conditions here in RI and how GHP works) is the best approach in estimating the economic viability of GHP here in RI.

6.4.1 Case Study Analysis

The case studies reviewed for this analysis have been chosen particularly for their regional characteristics, as Rhode Island's colder climate and large annual temperature range are of significant importance in determining the effectiveness of a GHP installation. Perhaps the most applicable case study is one of a 1998 Connecticut domicile[15]. This home installed a GHP system in place of an oil-fired burner, and a desuperheater, used to help heat the home's hot water. The propane water heater, normally used to heat the water, also serves as a backup space heater. The method chosen was vertical piping due to the rocky New England soil. The total cost was $19,283. After a $2,971 rebate ($200/kW from Northeast Utilities' energy performance program), the cost was reduced to $16,312. The quote for an oil-fired furnace and electric central air conditioning system was $16,200. With the rebate, the payback time for this installation was extremely short, only having to recover $112 through avoided fuel (oil burner) and electricity (air conditioning) costs. However, without the rebate, the system would have still been cost-effective. The high price of a central air conditioning system helped to make this particular case very affordable.

A 1995 compilation of 256 case studies[6] yielded various conclusions. It demonstrated that, in non-residential (commercial and municipal) applications, the simple payback time for the 17 cases examined was less than five years, with 75 percent of these cases being in northern climates. The residential dataset showed less promising results, with simple payback times ranging from 1.4 to 24.1 years across the 27 cases examined. However, with a mean payback time of 6.8 years and typical system life expectancies usually exceeding 20 years, this prognosis is economically favorable. Note also that this was compared to a natural gas furnace, the cheapest heating method in RI. However, this study also points out that caution "should be used in arriving at economical conclusions for any of the three groups presented in this paper. In part, this is due to the many variables associated with GHP systems and a variety of economic analysis methods used in the case studies. When considering a GHP system for either new or retrofit situations, it is imperative that a deliberate economic analysis be performed." In other words, from a statistical perspective, geothermal heat pumps show significant potential, but case-by-case analysis is still necessary. This may be facilitated by a number of numerical models, some commercial (see TRNSYS), others in the public domain (see RETScreen). Considering the significant growth in fuel prices since 1995, the conclusions reached in this study may be considered very conservative estimates.

6.4.2 Regional Knowledge

The rocky soil typical to New England will be a barrier to the usage of cheaper horizontal loop orientation of GHP piping. However, the added cost of using vertical loop piping may be offset by the more constant annual temperature, as temperature variation goes to zero with increasing depth. With this knowledge, site-specific testing of annual temperature variation is not as necessary. This cuts down on costs related to site review, something that is particularly important for smaller applications such as residential.

Detailed depth-to-bedrock information has not been compiled for this study (and likely does not exist), however past RI Department of Transportation projects have shown deep bedrock (~200 ft) to be present in much of the state. The data available apply particularly to the eastern half of the state. This is fortunate because the vast majority of the new housing construction projects are occurring in this region [54]. Thus, most new construction projects in RI are in good geological conditions for GHP utilization.

Rhode Island's cooler average soil temperature does bring into question whether GHP systems would be able to handle all household heating needs. However, coupling the GHP system with a standard water heater, as done in the Connecticut home discussed previously, would act as an inexpensive safeguard against this. This approach follows the concept of a HGHP system.

6.4.3 Technological Knowledge

Geothermal heat pumps are most effective when temperatures are most extreme—the coldest winter and hottest summer days. This correlates well with energy prices to the utility.

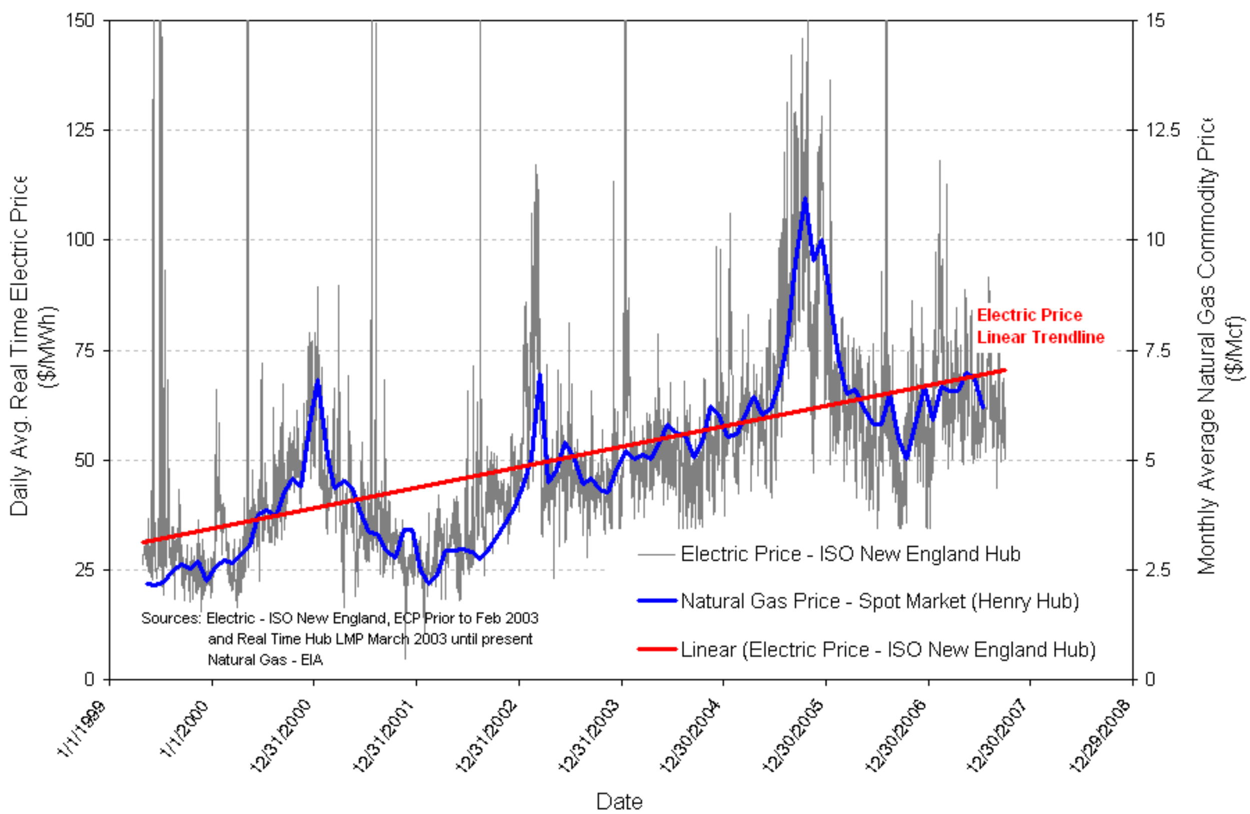


Figure 6.5: Natural Gas Price

Electricity prices peaks during the summer, largely due to cooling needs—a GHP's peak cooling performance occurs in the summer, reducing electricity demand. Natural gas prices peak during the winter, largely due to heating needs—a GHP's peak heating performance occurs in the winter, reducing natural gas demand. This combined effect of the naturally-occurring summer and winter demand-side reduction due to GHP systems can readily offset a significant portion of a building's seasonal peak loads. Furthermore, a major deployment of GHP systems in new construction would abate an increase in demand, helping to reduce the need for new generation projects.

The exact summer savings from a GHP system are difficult to estimate, as the costs associated with air conditioning are, themselves, difficult to estimate. However, due to the significant increase in annual home heating costs, the avoided heating costs may, alone, be enough to justify GHP systems in most cases.

GHP installations are, by far, most cost-effective when installed with a new building. This is due largely to the excavation costs associated with piping installation. Furthermore, the increased cost of a GHP system (~$8,000) is insignificant when compared to the cost of building a new home (~$250,000). At times, retrofit projects have still shown themselves to be cost-effective when compared to replacement of the current system. For instance, areas that are not heavily urbanized ease excavation costs. However, because this is not often the case, retrofit projects need more significant legislative support.

6.5 Conclusions

"Geoexchange (also called geothermal) heating and cooling systems are the most energy-efficient, environmentally clean and cost-effective space conditioning systems available." [16] This statement is from an EPA report in 1993, a time when energy prices (including natural gas) were less than half what they are in 2008. Geothermal heat pumps may represent the most promising small-scale energy source reviewed in this report. However, it also has one of the smallest datasets. This, combined with poor public knowledge, has led to very limited implementation. For large buildings, GHP systems almost always show a payback time less than five years, making them an excellent choice for commercial and industrial applications. In residences, there is wider variability. However, research performed for this study did not reveal a single case in which a GHP system did not pay itself back over the system's lifetime.

Thus, the major barriers to large-scale GHP implementation are the increased initial cost, poor public awareness, and lack of local experienced installers. These barriers are readily surmountable. A low-interest loan is necessary for all GHP. It is suggested that this loan, as a minimum, cover the difference in cost between a GHP system and a traditional heating system for a given building. This could be implemented by requiring participants to get price quotes for each and reporting the difference. The only direct financial commitment that may be needed is in the case of retrofit projects. Due to the limited amount of information available, it is suggested that the 25 percent tax credit be kept for retrofit projects.

The greatest issue is public awareness. It is suggested that, in particular, those in the construction industry are targeted in an educational program. While attempting to inform the general public of the benefits of GHP is advisable, a campaign targeted toward those involved in heating and cooling would be more easily realized and effective. Additionally, the number of qualified local installers should be assessed. If the number is found to be insufficient, training could become part of the education campaign.

7 BIOMASS, FUEL CELLS AND TIDAL POWER

7.1 Biomass

Biomass is currently used in Rhode Island as a fuel source for heating, predominately for residences. Prospectively, biomass, such as switch grass and poplar trees, may be a source of biofuels, which could be a substitute for petroleum. This is an active area of research. Biomass is not currently a strong candidate for investment through system reliability and least cost procurement.

7.2 Fuel Cells

Fuel cells are a renewable energy resource recognized in Chapter 39-26, for the most part, fuel cells are still in the research and development and are not commercially available in a manner that would make them a reasonable candidate for system reliability and least cost procurement.

7.3 Tidal Power

There are very few locations with tides and/or currents strong enough to support renewable energy development that is economically reasonable. Site conditions and site specific permitting considerations would, in any case, be determinative of project feasibility. These factors preclude making general recommendations for including tidal power as part of a system reliability and least cost procurement strategy.

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APPENDIX A: Methods

Cost-Benefit Analysis (CBA)

Cost-Benefit Analysis (CBA) was used to quantify the advantages (benefits) and disadvantages (costs) of installing small-scale renewable energy systems. The CBA calculates the tangible net costs and net benefits of the systems, normalized in monetary terms. The purposes of the CBA are: compare the benefits and costs; calculate benefit-costs ratios; calculate net benefits (NOAA).

First, the capital (initial) costs of the systems were determined for each type of renewable energy system based on the system's output. The capital costs included equipment, installation, permitting fees, and engineering and siting costs.

$$CC = C_p \cdot P \qquad \text{Equation 1}$$

Where:

CC = capital cost

C_p = normalized system price

P = system power rating

It is important to note that the capital costs are paid once over the lifespan of the system and represent the initial costs associated with the tangible (total) cost.

Also incorporated into the tangible cost was the annual operation and maintenance cost of the energy system. All costs were given a discount rate of 7percent over system lifespan. A discount rate is a rate at which society as a whole is willing to trade present benefits for future benefits. The discount rate of 7percent is the federally accepted rate used for a CBA and also takes into account the inflation rate (NOAA).

$$NPV = \sum_{t=0}^{N} \frac{C_t}{(1+r)^t} \qquad \text{Equation 2}$$

Where:

NPV = net present value

t = the time of the cash flow

N = the total time of the project

r = the discount rate

C_t = the net cash flow at time t

After determining both the total capital costs of the system and the total operation and maintenance costs over the system's lifespan, the two values were added together for total tangible costs.

To calculate the benefits of the renewable energy system to the end-user, total avoided fuel costs are assumed. Avoided fuel costs are based on kilowatt hour charges in affect for standard offer service on July 1, 2008 and include fuel generation, distribution and transmission costs. Therefore total tangible benefits are equal to total avoided fuel costs. These costs were derived from the EIA Annual Energy Outlook report, which gives fuel price forecasts through 2030. The avoided fuel costs were discounted at 4.6percent because the forecast is normalized to an inflation rate of 2.4percent.

After calculating the total tangible benefits, the total tangible costs were subtracted. The remaining value is the total value of the system over the 25 year life expectancy. A benefit-cost ratio, equal to the total tangible benefits divided by the total tangible costs, was also calculated. The total tangible benefits were divided by the total tangible costs. The benefit-cost ratio is used to summarize the overall value of the project being implemented and help determine if a project is cost-effective. If the value exceeds 1.0, a net profit is made; if the value is equal to one, the costs equal the benefits; if the value is less than 1.0, the project does not pay for itself.

Solar

The cost-benefit analysis for PV was done following the format given above. Details on the equations used are as follows.

The total amount of capital made by a PV system, C, over its lifespan, T, can be calculated as,

$$C = T\overline{E}D \qquad \text{Equation 3}$$

where $\overline{E}$ is the average power generated by the system and D is the price per unit energy of the fuel that would otherwise be needed (avoided fuel costs), modified for an inflation or discount rate.

$\overline{E}$ may be calculated by multiplying the total solar irradiance across the area of the solar collector, A, by an efficiency, η, or,

$$\overline{E} = E_{sun} A \eta \qquad \text{Equation 4}$$

This efficiency is calculated relative to a standard irradiance (E_s) of 1.0 kW/m^2 and is defined by,

$$\eta = \frac{P_m}{E_s A} \qquad \text{Equation 5}$$

where P_m is the power rating of the module. Efficiencies range by model, but are usually around 10percent to 20percent.

Thus, the money generated by a given solar system may be calculated by combining equation 3 with equation 4 (into which equation 5 has been substituted), yielding,

$$C = TE_{sun} \frac{P_m}{E_s} D \qquad \text{Equation 6}$$

An additional derate factor, R, must also be included because panels generate power as direct current (DC), but using this power necessitates that it be converted to alternating current (AC), and some power is lost during this conversion. Determination of this value is complex, however it is always between 0 (full loss) and 1 (lossless) and should certainly be closer to 1. Including this term and rearranging the equation to show the revenue generated per unit power system rating,

$$\frac{C}{P_m} = \frac{TE_{sun} DR}{E_s} \qquad \text{Equation 7}$$

Wind

Total costs and benefits were compared across the upper range of standard wind speed classes 1-4 (Table 4.1). Only one system size was used because a wind turbine is limited by wind speeds and their consistency, more than the capacity and efficiency of the system. An average capital cost of $47,123 was used from prices calculated for varying tower heights (Table 4.3). An O & M cost of $0.015/kWh was based on previous studies of small scale turbines[11] and adjusted based on the energy output of the system at each of the wind speeds. Using the average capital cost, O & M costs across the life of the system, and avoided fuel costs the NPV of the system could be compared across different wind speeds.

Hydroelectricity

To calculate the CBA for hydroelectricity, two studies were used to estimate costs: 1) a GIS tool developed by the INEL; 2) a "Statewide Small Hydropower Resource Assessment" developed for the CEC (see Table 1).

Table 1. Table developed for the California Energy Commission showing the levelized costs of energy by size of hydropower facility assuming no subsidies.

Head Range	kW	Head (ft)	cfs	Turbine Effic %	Average Load Factor %	Capital Costs $/kW	O&M Costs $/MWhr	LCOE $2004 $/kWhr
Very Low	101	7	286	68.3%	51.4%	$8,574	$11.50	$0.210
	1478	13	1800	85.2%	51.4%	$2,384	$11.50	$0.067
	1002	19	805	88.3%	51.4%	$2,098	$11.50	$0.060
Low	100	20	55	86.5%	51.4%	$3,330	$11.50	$0.089
	1068	32	500	91.1%	51.4%	$1,309	$11.50	$0.042
	1003	44	335	91.7%	51.4%	$1,092	$11.50	$0.037
Medium	102	45	46	70.8%	51.4%	$4,039	$11.50	$0.105
	1066	72	250	84.3%	51.4%	$1,124	$11.50	$0.038
	1004	100	162	87.6%	51.4%	$ 999	$11.50	$0.035
High	100	100+	10	84.9%	51.4%	$2,220	$11.50	$0.063
	308	101	50	86.4%	51.4%	$1,419	$11.50	$0.044
	1004	101	161	87.7%	51.4%	$1,037	$11.50	$0.036

The Virtual Hydropower Prospector, a GIS tool developed by the INEL, showed locations of all potential hydroelectric sites with pre-existing dams in Rhode Island.[53] The report provides head and flow rate for all sites excluding microhydro, as many do not require the use of a dam. A histogram created from the INEL data shows the number of dams within various energy classes. Samples were appropriately chosen based on frequency of potential sites.

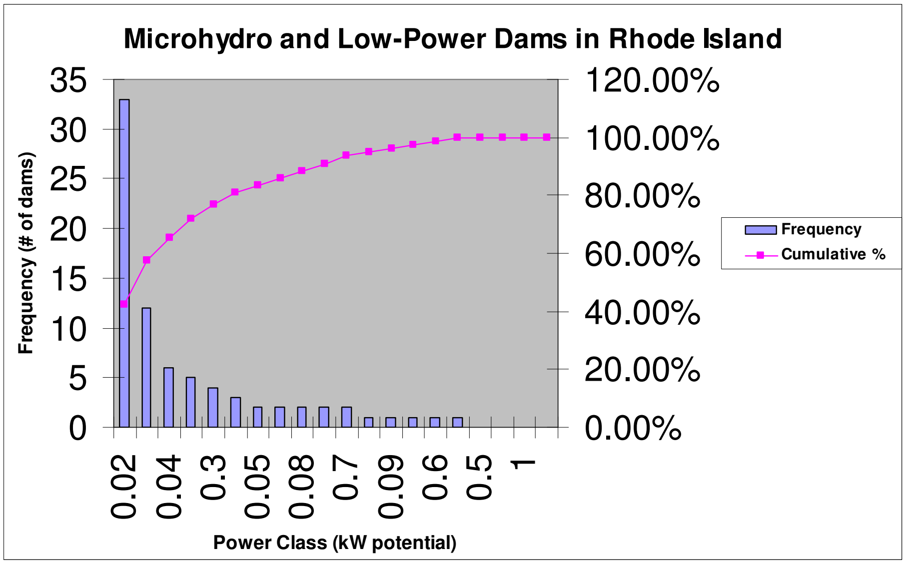


Figure 1: The kilowatt potential for microhydro and low-power dams in Rhode Island distributed according to power class demonstrates that the majority of these dams have low energy potential. Although there are fewer high-energy-producing sites, their potential equals almost three megawatts of electricity.

The four sites chosen were:

- Harrisville Pond, Pascoag River, Burrillville (29 kW, high hazard dam)
- Mapleville Pond, Chepachet River, Burrillville (57 kW, high hazard dam)
- Horseshoe Falls,Pawcatuck River, Charlestown/Richmond (106 kW, significant hazard dam)
- Woonsocket Falls, Blackstone River, Woonsocket (658 kW significant hazard dam)

A CBA was performed on each of the four sites at the highest estimated efficiency, 85percent, and the lowest estimated efficiency, 60percent. The efficiencies were determined through an interview with an environmental engineer, from St. Onge Environmental Engineering, PLLC., who specializes in hydropower installation. Also, due to the fact that there was a variation in capital costs according to system size, a Capital Cost A and Capital Cost B were calculated. These costs were determined based on the California Energy Commission Report (Table 1). Therefore, for each site and each efficiency level, two capital costs were calculated and used to create a range of costs for the various systems that could be installed (see Table 2).

Table 2: Extracted from the CBA of the Harrisville Pond dam in Burrillville, which can potentially produce 29kW of energy. This table shows how the calculations were divided by efficiencies and by capital costs to determine a cost range for various systems.

	85percent efficiency			**60percent Efficiency**		
Tangible Costs	**Amount**	**Year**	**Discount Rate**	**Amount**	**Year**	**Discount Rate**
Capital Costs A ($2000/kW)	$58,000	0	7percent	$58,000	0	7percent
Capital Costs B ($8500/kW)	$246,500	0		$246,500	0	
Annual Costs						
Operation & Maintenance	$28,938.66	1--25		$20,427.29	1--25	
Total Tangible Costs A	$86,939			$78,427		
Total Tangible Costs B	$275,439			$266,927		

Cost-Effectiveness Analysis (CEA) for Hydroelectricity

A CEA is an analytic tool used to compare the costs of various project alternatives that achieve similar benefits. A CEA is useful when the benefits of a project are not easily quantifiable, or when a specific goal is targeted and designed to meet the minimum requirements of a policy or regulatory scenario.

With regards to this analysis, the CEA was used to determine the economic benefits of coupling dam repair with small-scale hydropower installation. By comparing the alternatives of repairing high hazard and significantly hazardous dams to repairing the dam as well as installing hydropower, the least cost alternative can be determined.

Site Selection

Initially four sites were determined that had both pre-existing dams and hydropower potential. The Virtual Hydropower Prospector, a GIS tool developed by the INEL, showed locations of all potential hydroelectric sites with pre-existing dams in Rhode Island.[53] A histogram created from the INEL data shows the number of dams within various energy classes (Figure 1). Samples were appropriately chosen based on frequency of potential sites.

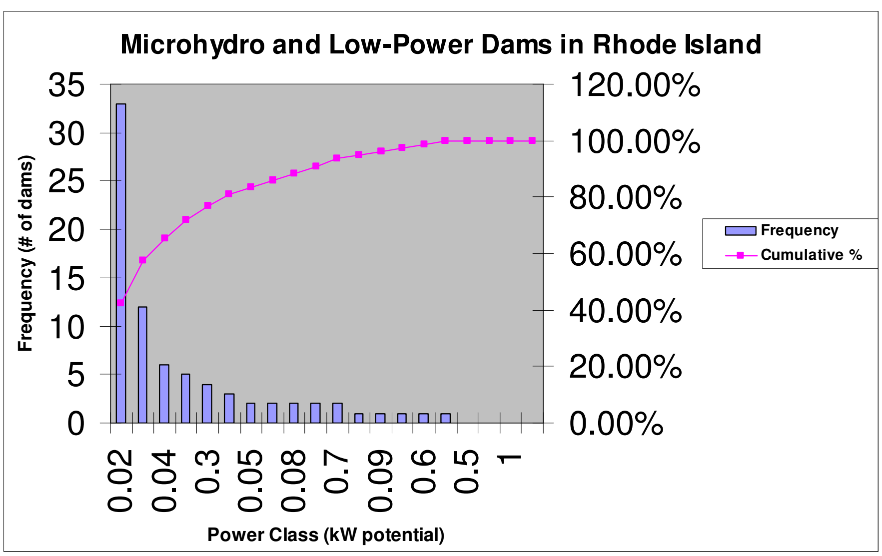


Figure 1: The kilowatt potential for microhydro and low-power dams in Rhode Island distributed according to power class demonstrates that the majority of these dams have low energy potential. Although there are fewer high-energy-producing sites, their potential equals almost three megawatts of electricity.

The four sites chosen were:

- Harrisville Pond, Pascoag River, Burrillville (29 kW, high hazard dam)
- Mapleville Pond, Chepachet River, Burrillville (57 kW, high hazard dam)
- Horseshoe Falls, Pawcatuck River, Charlestown/Richmond (106 kW, significant hazard dam)
- Woonsocket Falls, Blackstone River, Woonsocket (658 kW significant hazard dam)

Energy Output

A CEA was performed on each of the four sites at the highest estimated efficiency, 85percent, and the lowest estimated efficiency, 60percent. The efficiencies were determined through an interview with an environmental engineer, from St. Onge Environmental Engineering, PLLC., who specializes in hydropower installation. It should be noted that the outputs were also calculated in both kilowatts and kilowatt hours for future calculations and comparisons (Table 1).

Table 1: The energy outputs calculated for the four potential hydropower sites in both kilowatts and kilowatt hours.

Energy Output	***units***	***29 kW***	***57 kW***	***106 kW***	***658 kW***
60percent x kW	kW	17.4	34.2	63.6	394.8
85percent x kW	kW	24.65	48.45	90.1	559.3
60percent x kW x 3600	kWh	62640	123120	228960	1421280
85percent x kW x 3600	kWh	88740	174420	324360	2013480

Dam Repair Costs

Costs for dam repair, dam inspection and application fees for dam repairs were all accounted for in the dam repair costs. The dam owner would be responsible for these costs in order to repair a significantly hazardous or high hazard dam. Dam repair costs were derived in the 2007 RIDEM Dam Safety report ($800,000) and an interview with a dam engineering expert of Fay Engineering Services ($625,000).

Dam inspection costs were calculated based on two values, $2,500 and $3,000, found in the RIDEM Rules and Regulations for Dam Safety. High hazard dam visual inspections take place every two years and significantly hazardous dams are visually inspected every five years. Therefore dam inspection costs were calculated over the life expectancy of the hydropower system (25 years) at every two years and at every five years. This was done with both the high cost and the low cost of inspections. Over the 25 year analysis, the inspection costs were discounted at a rate of 7percent (Table 2).

Table 2: Inspection costs over the 25 year life expectancy of a hydropower system, for both the high hazard dam and significant hazard dam inspection time intervals and at $2,500 and $3,000

Inspection Costs	*units*	
High Hazard x $2500	$/life	$15,282.11
High Hazard x $3000	$/life	$18,338.53
Significant Hazard x $2500	$/life	$10,250.49
Significant Hazard x $3000	$/life	$12,300.59

The dam repair costs, permitting fees and the inspections costs were then combined in order to find the total cost of high hazard and significantly hazardous dam repairs. These costs were found at: the high dam repair cost and the low cost; the various high hazard and significantly hazardous inspection time intervals; the high and low costs of dam inspections (Table 3).

Table 3: Combine dam repair costs and inspection costs at various high costs and low costs and time intervals.

Dam Repair	*units*	*Hihazard, $3000*	*hihazard, $2,500*	*sighaz. $3,000*	*sighaz $2,500*
DamRep + inspection	$/25yrs	$643,338.53	$640,282.11	$637,300.59	$635,250.49
DamRep2 + inspection	$/25yrs	$818,338.53	$815,282.11	$812,300.59	$810,250.49

Hydropower System Costs

The capital of the hydropower system was based on the system's output, and included; equipment, installation, permitting fees and engineering costs (Equation 1).

$$CC = C_p \cdot P \qquad \text{Equation 1}$$

Where:
CC = capital cost
C_p = normalized system price
P = system power rating (potential)

The capital costs are paid once throughout the life expectancy of the system, estimated to be approximately 25 years for a hydropower system (Table 4).

Table 4: Hydropower system cost per kW for the four potential sites, derived from the INEL database and comparisons with the CEC report.

System cost per kW	***units***	***29 kW***	***57 kW***	***106 kW***	***658 kW***
potential power x $2000 x kW	$/kW	$58,000.00	$114,000.00	$212,000.00	$1,316,000.00
potential power x $8500 x kW	$/kW	$246,500.00	$484,500.00	$765,850.00	$5,593,000.00

The hydropower system and installation costs were derived from the CEC report (Table 5), which lists capital costs of hydropower systems in cost per kW. The head and flow of the four sites chosen above were found in the INEL database and a range of capital costs were determined by comparing dams with similar capacities, described in Table 6.

Table 5: Table developed for the California Energy Commission showing the normalized costs of energy by size of hydropower facility assuming no subsidies.

Head Range	kW	Head (ft)	cfs	Turbine Effic %	Average Load Factor %	Capital Costs $/kW	O&M Costs $/MWhr	LCOE $2004 $/kWhr
Very Low	101	7	286	68.3%	51.4%	$8,574	$11.50	$0.210
	1476	13	1600	85.2%	51.4%	$2,384	$11.50	$0.067
	1002	19	805	88.3%	51.4%	$2,098	$11.50	$0.060
Low	100	20	55	86.5%	51.4%	$3,330	$11.50	$0.089
	1068	32	500	91.1%	51.4%	$1,309	$11.50	$0.042
	1003	44	335	91.7%	51.4%	$1,092	$11.50	$0.037
Medium	102	45	46	70.8%	51.4%	$4,039	$11.50	$0.105
	1066	72	250	84.3%	51.4%	$1,124	$11.50	$0.038
	1004	100	162	87.6%	51.4%	$ 999	$11.50	$0.035
High	100	100+	10	84.9%	51.4%	$2,220	$11.50	$0.063
	308	101	50	86.4%	51.4%	$1,419	$11.50	$0.044
	1004	101	161	87.7%	51.4%	$1,037	$11.50	$0.036

Also included was the operation and maintenance cost for a hydropower system. This value was calculated based on a report by the CEC, with a hydropower O&M of $11.50/MW. The cost was then converted to cost per kW (Table 6).

Table 6: The operation and maintenance cost per kilowatt for each potential hydropower systems calculated at both 85 percent efficiency and 60percent efficiency.

O&M cost per kW	***units***	***29 kW***	***57 kW***	***106 kW***	***658 kW***
85percent x $0.0115 x kW	$/kW	$0.28	$0.56	$1.04	$6.43
60percent x $0.0115 x kW	$/kW	$0.20	$0.39	$0.73	$4.54

The cost per kilowatt was then calculated over a 25 year period for each potential system. The values were discounted at 7percent to find the net present value of the operation and maintenance costs (Table 7).

Table 7: Hydropower system costs based on the highest projected costs and lowest projected costs are listed in order to ensure that a range of costs could be determined.

O&M (discounted 7percent, over 25 yrs.)	***29 kW***	***57 kW***	***106 kW***	***658 kW***
O&M, total low kWh, 25 year life expectancy	$20,427.29	$40,150.18	$74,665.25	$463,488.08
O&M, total hi kWh, 25 year life expectancy	$28,938.66	$56,879.43	$105,775.78	$656,608.12

Dam Repair Coupled with Hydropower

The total costs were then combined for each potential site (i.e. capital costs and operation and maintenance costs). The dam repair costs include the inspection costs at the highest value and the lowest value calculated. Therefore, the high dam repair cost and the high inspection cost are referred to as *DamRephi* and the lowest dam repair cost and the lowest dam inspection cost are referred to as *DamReplo*. This allows for a range of high and low costs to estimate from.

Also, for operation and maintenance costs as well as hydropower system costs, the highest and lowest possible values were used to determine a range of costs. The application fees are constant. The different combinations of dam repair, operation and maintenance and system costs demonstrate the variation in costs at different potential system capacities (Table 8).

Table 8: The dam repair, operation and maintenance and system costs as well as application fees are totaled at the highest and lowest costs for a range of costs at each of the four potential sites.

Total Cost	*units*	*29 kW*	*57 kW*	*106 kW*	*658 kW*
DamReplo + application fees + O&M total(lo) + System (lo)	$	$716,277.78	$792,000.68	$924,515.75	$2,417,338.58
DamReplo + application fees + O&M total(hi) + System (hi)	$	$913,289.15	$1,179,229.92	$1,509,476.27	$6,887,458.61
DamRephi + application fees + O&M total(lo) + System (lo)	$	$899,365.81	$975,088.71	$1,107,603.78	$2,600,426.61
DamRephi + application fees + O&M total(hi) + System (hi)	$	$1,096,377.18	$1,362,317.95	$1,692,564.30	$7,070,546.64

Applied Benefits

Although a CEA does not take into account the benefits of the project alternatives, the production of electricity by the hydropower system, can be considered in the analysis to show cost reduction of the system over time. By installing a hydropower system there are avoided fuel costs that the owner of the dam may benefit from.

To calculate the benefits of the renewable energy system to the end-user, total avoided fuel costs are assumed. Therefore total tangible benefits are equal to total avoided fuel costs. These costs were derived from the EIA Annual Energy Outlook report, which gives fuel price forecasts through 2030. The avoided fuel costs were discounted at 4.6percent because the forecast is normalized to an inflation rate of 2.4percent (Table 9).

Table 9: The benefits calculated from the EIA Annual Energy Outlook report, calculated at both 85 percent efficiency and 60 percent efficiency for each of the potential sites.

Benefits (discounted 4.6percent, over 25 yrs.)	*units*	*29 kW*	*57 kW*	*106 kW*	*658 kW*
85percent efficiency	$	$527,478.61	$1,036,768.30	$1,928,025.26	$11,968,307.72
60percent efficiency	$	$372,337.84	$731,836.45	$1,360,959.00	$8,448,217.21

The avoided fuel costs were then subtracted from the total cost of dam repair and the hydropower system. The benefits at both 85percent efficiency (*benefits (hi)*) and 60percent efficiency (*benefits (lo)*) were used. Also, the high and low costs from dam repair, operation and maintenance, and system costs were used in order to calculate the highest values and lowest values at each potential site (Table 10).

Table 10: Avoided fuel costs, discounted at 4.6percent over 25 years, were subtracted from the total costs of dam repair, the hydropower system, O&M costs and application fees for each potential site. Although for the 29kW and 57kW sites a cost is still incurred on the dam owner, it is less than dam repair costs alone. For the larger systems (106kW and 658kW), the dam repair and hydropower system is fully paid for.

Avoided Fuel - Total Cost	***units***	***29 kW***	***57 kW***	***106 kW***	***658 kW***
benefits (lo) - [DamReplo + app fees + O&M total(lo) + System (lo)]	$	-$343,939.94	-$60,164.23	$436,443.26	$6,030,878.64
benefits (hi) - [DamReplo + app fees + O&M total(hi) + System (hi)]	$	-$385,810.54	-$142,461.62	$418,548.99	$5,080,849.11
benefits (lo) - [DamRephi + app fees + O&M total(lo) + System (lo)]	$	-$527,027.97	-$243,252.26	$253,355.22	$5,847,790.60
benefits (hi) - [DamRephi + app fees + O&M total(hi) + System (hi)]	$	-$568,898.57	-$325,549.66	$235,460.95	$4,897,761.07

APPENDIX B: Wind

1. Parameters Used to estimate energy output

A. 10 percent Turbulence Factor : Turbulence Factor is a derating for turbulence, product variability, and other performance influencing factors. 10percent was chosen because of RI's hilly topography and vast tree cover.

B. 61m Mean Elevation: The mean elevation for all of Rhode Island was used as most lands in Rhode Island are considered coastal.

C. Weibull distribution of k=3: Wind speed probability is calculated as a Weibull curve defined by the average wind speed and a shape factor, K. A K value of 3 is used as a standard for coastal areas.

D. 30m anemometer height: This is the typical hub height of a small-scale turbine.

E. Upper range of standard wind speed classes: 1-4 (Table 4.1)

2. Cost-Benefit Analysis: Complete Table

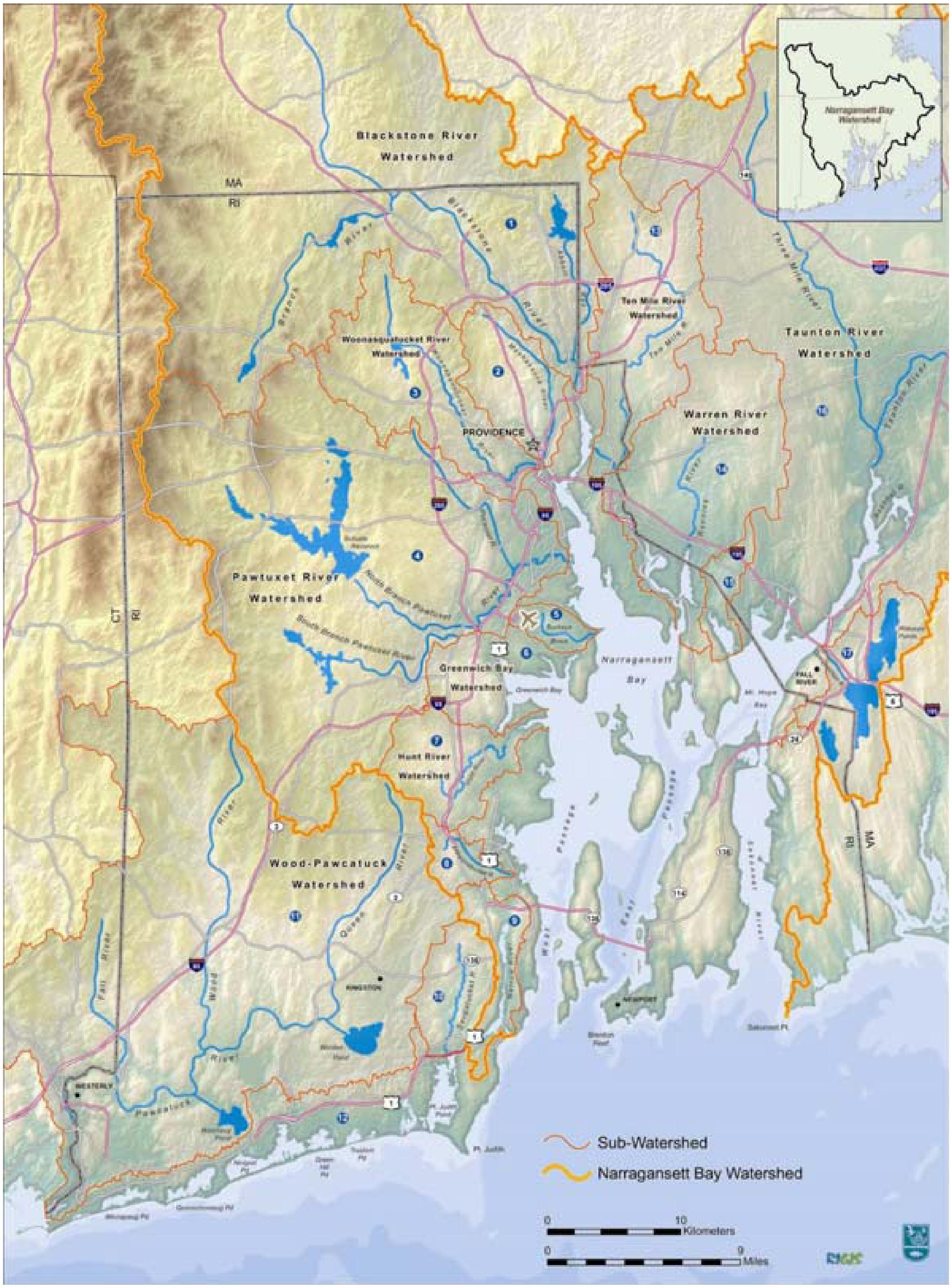
Cost-Benefit Analysis: Small-scale Wind Power (10kW)

Wind Speed Class	**1**	**2**	**3**	**4**
Tangible Costs				
Average Capital Cost	$47,123	$47,123	$47,123	$47,123
Operation & Maintenance*°	$1,562.63	$2,427.15	$3,161.27	$3,811.25
Total Tangible Costs A	$48,686	$49,550	$50,284	$50,934
Tangible Benefits				
Immediate Benefits	0	0	0	0
Avoided Fuel Costs**°	$21,835.98	$33,917.96	$44,176.81	$53,259.87
Total Tangible Benefits	$21,835.98	$33,917.96	$44,176.81	$53,259.87
Benefits-Cost	$26,849.65	$15,632.19	$6,107.46	$2,325.62
Benefits/Costs	0.448509838	0.684517777	0.878541339	1.045659274

*Discounted 7 percent, includes inflation
**Discounted 4.6 percent, fuel projections already account for inflation
°Over 25 year life of the system

APPENDIX C: Hyrdoelectricity

Map of Rhode Island Topography and Waterways



Narragansett Bay Watershed Ecosystem, courtesy of R.I. DEM

Efficiency of Turbine Types Based on Sit Characteristics

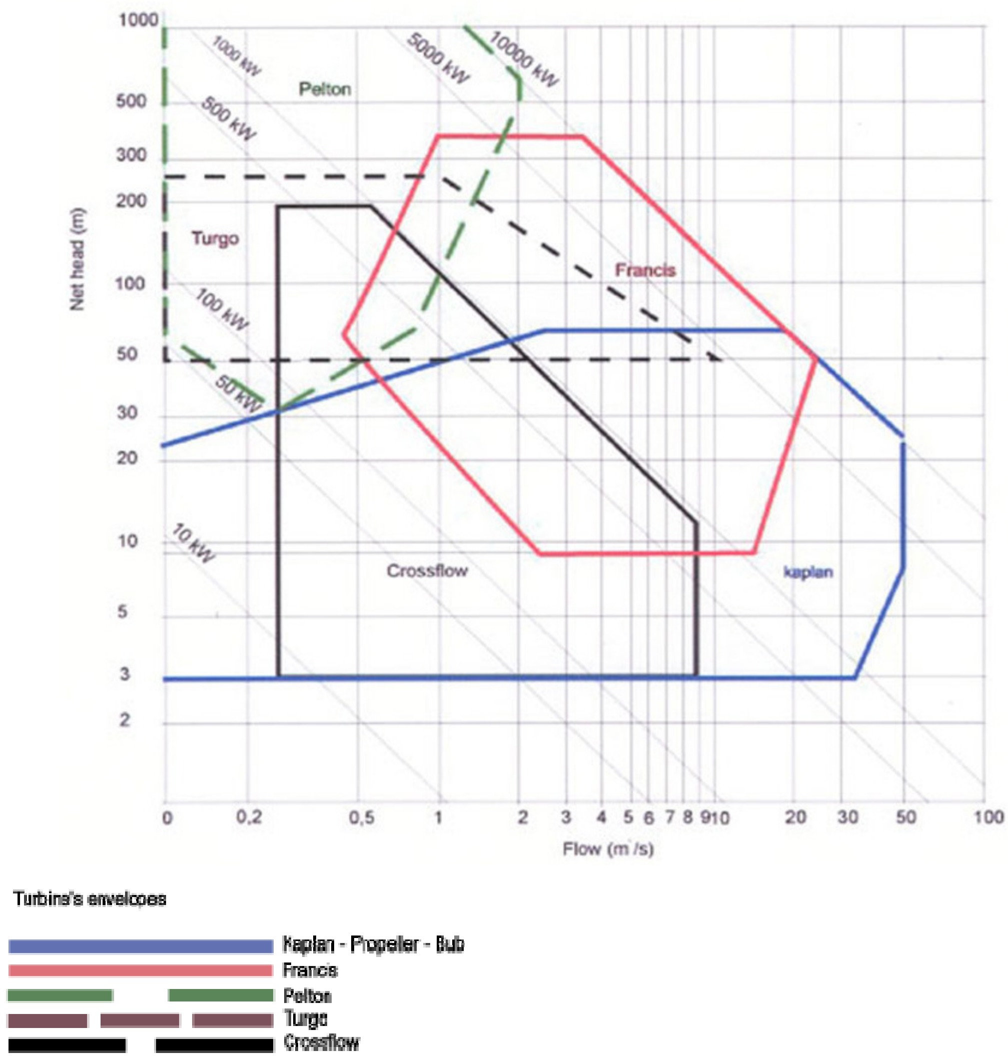


Diagram shows varying efficiency of turbine types based on site characteristics. Design is an important issue power station construction. Usually, the engineer evaluates the merits of various arrangements for the site before deciding on the best design. The engineer might compare single versus multiple units

- propellor (fixed blade) versus Kaplan (variable pitch blade)
- Francis versus Pelton

GIS High Hazard Dam Failure Flood Projection

Oak Swamp Dam (No. 168), Johnston, DEM safety and compliance report, 2007

APPENDIX D: Solar

Table 1: PV Cost-Benefit Analysis with Tax Credit

Tax Credit										
Year yr	Energy price $/kWyr	Yearly revenue $/kW	Cumulative revenue $/kW	System price $/kW	Installation cost $/kW	Inverter Cost $/kW	Yearly Cost $/kW	Cumulative cost $/kW		Cumulative net revenue $/kW
2008	1447.19	227.933	227.933	3500	2345	--	5845	5845.000		-5617.067
2009	1497.74	225.520	453.453	--	--	--	0	5845.000		-5391.547
2010	1456.79	209.708	663.161	--	--	--	0	5845.000		-5181.839
2011	1456.80	200.487	863.648	--	--	--	0	5845.000		-4981.352
2012	1467.71	193.106	1056.753	--	--	--	0	5845.000		-4788.247
2013	1455.96	183.136	1239.889	--	--	--	0	5845.000		-4605.111
2014	1454.76	174.937	1414.826	--	--	666.342	666.34222	6511.342		-5096.516
2015	1439.67	165.509	1580.335	--	--	--	0	6511.342		-4931.007
2016	1436.83	157.918	1738.253	--	--	--	0	6511.342		-4773.089
2017	1446.71	152.012	1890.265	--	--	--	0	6511.342		-4621.077
2018	1455.71	146.231	2036.496	--	--	--	0	6511.342		-4474.846
2019	1456.69	139.894	2176.390	--	--	--	0	6511.342		-4334.952
2020	1446.63	132.818	2309.208	--	--	--	0	6511.342		-4202.134
2021	1436.21	126.062	2435.271	--	--	414.964	414.96445	6926.307		-4491.036
2022	1443.70	121.147	2556.418	--	--	--	0	6926.307		-4369.889
2023	1448.85	116.233	2672.651	--	--	--	0	6926.307		-4253.656
2024	1457.02	111.748	2784.399	--	--	--	0	6926.307		-4141.908
2025	1455.51	106.723	2891.122	--	--	--	0	6926.307		-4035.185
2026	1467.41	102.863	2993.985	--	--	--	0	6926.307		-3932.321
2027	1462.16	97.988	3091.974	--	--	--	0	6926.307		-3834.333
2028	1479.94	94.818	3186.792	--	--	258.419	258.419	7184.726		-3997.934
2029	1491.29	91.344	3278.135	--	--	--	0	7184.726		-3906.591
2030	1479.78	86.653	3364.788	--	--	--	0	7184.726		-3819.938
2031	1479.78	82.842	3447.629	--	--	--	0	7184.726		-3737.096
2032	1479.78	79.199	3526.828	--	--	--	0	7184.726		-3657.898
		lifecycle revenue					lifecycle cost			lifecycle net revenue
	$/kW	3526.828				$/kW	7184.726		$/kW	-3657.898

Table 2: PV Cost-Benefit Analysis with Loan and 150% Net Metering

LOAN & 150% Net Metering										
Year yr	Energy price $/kWyr	Yearly revenue $/kWyr	Cumulative revenue $/kW	System price $/kW	Installation cost $/kW	Inverter Cost $/kW	Yearly Cost $/kW	Cumulative cost $/kW		Cumulative net revenue $/kW
2008	1447.19	341.900	341.900	233.333	156.3333	--	389.66667	389.667		-47.767
2009	1497.74	338.280	680.180	223.072	149.4583	--	372.53027	762.197		-82.017
2010	1456.79	314.562	994.741	213.262	142.8855	--	356.14749	1118.344		-123.603
2011	1456.80	300.730	1295.471	203.883	136.6018	--	340.48517	1458.830		-163.358
2012	1467.71	289.659	1585.130	194.917	130.5945	--	325.51164	1784.341		-199.211
2013	1455.96	274.704	1859.833	186.345	124.8513	--	311.19659	2095.538		-235.704
2014	1454.76	262.405	2122.239	178.15	119.3607	666.342	963.85331	3059.391		-937.152
2015	1439.67	248.264	2370.502	170.316	114.1116	--	284.42742	3343.819		-973.316
2016	1436.83	236.877	2607.380	162.826	109.0933	--	271.91914	3615.738		-1008.358
2017	1446.71	228.018	2835.398	155.665	104.2957	--	259.96094	3875.699		-1040.301
2018	1455.71	219.346	3054.744	148.82	99.70909	--	248.52862	4124.227		-1069.483
2019	1456.69	209.841	3264.585	142.275	95.32418	--	237.59906	4361.826		-1097.241
2020	1446.63	199.227	3463.813	136.018	91.1321	--	227.15016	4588.976		-1125.164
2021	1436.21	189.094	3652.906	130.036	87.12438	414.964	632.12521	5221.102		-1568.196
2022	1443.70	181.721	3834.627	124.318	83.2929	--	207.61067	5428.712		-1594.086
2023	1448.85	174.349	4008.976	0	0	--	0	5428.712		-1419.736
2024	1457.02	167.622	4176.598	0	0	--	0	5428.712		-1252.114
2025	1455.51	160.085	4336.683	0	0	--	0	5428.712		-1092.029
2026	1467.41	154.295	4490.978	0	0	--	0	5428.712		-937.734
2027	1462.16	146.982	4637.961	0	0	--	0	5428.712		-790.752
2028	1479.94	142.227	4780.187	0	0	258.419	258.419	5687.131		-906.944
2029	1491.29	137.015	4917.203	0	0	--	0	5687.131		-769.929
2030	1479.78	129.979	5047.181	0	0	--	0	5687.131		-639.950
2031	1479.78	124.263	5171.444	0	0	--	0	5687.131		-515.687
2032	1479.78	118.798	5290.242	0	0	--	0	5687.131		-396.889
		lifecycle revenue					lifecycle cost			lifecycle net revenue
	$/kW	5290.242				$/kW	5687.131		$/kW	-396.889

RHODE ISLAND RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
RI-1	**Residential Renewable Energy Tax Credit (Corporate)** (R.I.G.L. § 44-57-1, et seq.)	Amount: 25% of costs; Maximum Incentive: Based on maximum system cost of $15,000 for PV, active solar space heating and wind; Based on $7,000 maximum system cost for solar hot water and geothermal	Commercial, Residential	Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Geothermal Heat Pumps
RI-2	**Small Customer Incentive Program for Green Power Marketers**	$125 per customer for first 6,000 customers; $75 per customer thereafter 06/30/2008	Retail Supplier	Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Fuel Cells, Anaerobic Digestion, Small Hydroelectric
RI-3	**Residential Renewable Energy Tax Credit (Personal)** (R.I.G.L. § 44-57-1, et seq.)	Amount: 25% of costs; Maximum Incentive: Based on maximum system cost of $15,000 for PV, active solar space heating and wind; Based on $7,000 maximum system cost for solar hot water and geothermal	Commercial, Residential	Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Geothermal Heat Pumps
RI-4	**People's Power & Light - Renewable Energy Certificate Incentive**	Institutional Amount: $0.03 per kWh Terms: 3-year contract	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, State Government, Fed. Government	Photovoltaics, Wind
RI-5	**Local Option - Property Tax Exemption for Renewable Energy Systems** (R.I.G.L § 44-3-21)	Allows cities and towns to exempt renewable-energy systems from property taxation	Residential	Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Biomass, Small Hydroelectric
RI-6	**Solar Property Tax Exemption** (R.I. Gen. Laws § 44-57-4 (a)(6))	Assessed at no more than conventional energy systems	Residential	Solar Water Heat, Solar Space Heat, Photovoltaics
RI-7	**Renewable Energy Sales Tax Exemption** (R.I.G.L § 44-18-30)	100% exemption	Commercial, Residential, General Public/Consumer	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Photovoltaics, Wind, Geothermal Heat Pumps, Solar Pool Heating

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=RI&RE=1&EE=0

RHODE ISLAND RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
RI-8	**National Grid - Solar Thermal Rebate Program**	$3 per therm, based on estimated first-year savings; Maximum Incentive: 50% of project costs, up to $100,000 per project	Commercial, Industrial, Multi-Family Residential Incentive	Solar Water Heat, Solar Space Heat, Solar Thermal Process Heat, Solar Pool Heating
RI-9	**Green Building Standards for State Facilities** (RI Executive Order 05-14)	New state construction projects must be designed to qualify for LEED "Silver" certification	State Government	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Biomass, Geothermal Heat Pumps, CHP/Cogeneration, Bio-gas, Daylighting, Small Hydroelectric
RI-10	**Energy Source Disclosure** (R.I. Gen. Laws § 39-26-9 CRIR 90-060-014)	Suppliers must disclose NE-GIS emissions (in pounds/MWh) quarterly:	Retail Supplier	Renewables, Nuclear, Natural Gas, Oil, Coal, Hydroelectric, Other NE-GIS Resources
RI-11	**Rhode Island - Green Power Purchasing** (Executive Order 06-02)	State government buys 20% by 2011	State Government	Wind, Hydroelectric
RI-12	**Rhode Island - Net Metering** (R.I. PUC Order, Docket No. 2710) (R.I. Gen. Laws § 39-1-27.7) (R.I. Gen. Laws § 39-26-6)	Limit on System Size: 1.65 MW for systems owned by cities, towns or the Narragansett Bay Commission; 1 MW for all other customers. Limit on Overall Enrollment: 5 MW (1 MW of this limit is reserved for systems under 25 kW) Treatment of Net Excess: Credited at utility's avoided-cost rate to customer's next bill; granted to utility at end of 12-month period	Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=RI&RE=1&EE=0

RHODE ISLAND RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
RI-13	**Renewable Energy Standard** (R.I. Gen. Laws § 39-26-1 et seq.) (CRIR 90-060-015)	16% by 2020; Credit Trading: Yes	Utility, Retail Supplier	Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Biodiesel, Fuel Cells using Renewable Fuels
RI-14	**Public Benefits Fund** (R.I. Gen. Laws § 39-2-1.2) (H 8025 (2006))	Demand-side management, renewables, low-income assistance Charge: $0.0023 per kWh (2.3 mills per kWh)	Commercial, Industrial, Residential, General Public/Consumer, Utility, Institutional	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Renewable Transportation Fuels, Geothermal Electric, Cofiring, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Fuel Cells using Renewable Fuels
RI-15	**Solar Easements** (R.I. Gen. Laws § 34-40) (R.I. Gen. Laws § 45-24-33)	Allows property owners to grant solar easements in the same manner and with the same effect as a conveyance of an interest in real property.	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, State Government, Fed. Government	Solar
RI-16	**Photovoltaic Grant Program**	Non-profits: $3.50/watt DC For-profits: $3/watt DC Maximum (non-profits): $87,500 Maximum (for-profits): $75,000	Commercial, Industrial, Nonprofit, Local Government, State Government, Institutional	Photovoltaics

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=RI&RE=1&EE=0

CONNECTICUT RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
CT-1	**CCEF - Solar Rebate Program**	- Residential: $5/W for first 5 kW; $4.30/W for next 5kW - Gov't/Non-profit: $5/watt - Up to $46,500 residential - Up to $50,000 Gov't/Non-profit - Up to 10 kW	Residential, Nonprofit, Local Gov., State Gov., Multi-Family Residential, Institutional	Photovoltaics
CT-2	**Property Tax Exemption** (Conn. Gen. Stat. § 12-81 (56, 57, 62, 63) [previous law]) (HB 7432 (Sec. 46))	100% exemption for renewable energy property; municipalities are authorized to exempt CHP systems	Commercial, Industrial, Residential, Multi-Family Residential, Agricultural	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Geothermal Heat Pumps, CHP/Cogeneration, Tidal Energy, Wave Energy, Ocean Thermal
CT-3	**Sales Tax Exemption** (HB 7432 (Sec. 68, 69))	100% sales tax exemption	Commercial, Residential, General Public/Consumer	Solar Water Heat, Solar Space Heat, Photovoltaics, Geothermal Heat Pumps
CT-4	**CCEF - Operational Demonstration Program** (Industry Recruitment/Support Program) (Conn. Gen. Stat. § 16-245n)	Up to $750,000 Connecticut Clean Energy Fund (CCEF) $4 million (total budget)	Commercial	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Fuel Cells, CHP/Cogeneration, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Other Distributed Generation Technologies
CT-5	**CCEF - Project 150 Initiative** (State Grant Program) (Conn. Gen. Stat. § 16-244c)	Minimum grant of $50,000 + premium of 5.5¢ per kWh for electricity generated during contract period	Commercial, Renewable energy project developers	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Fuel Cells, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal
CT-6	**CCEF - Community Innovations Grant Program**	$5,000 per community / $250-$2,000 per microgrant	Local Government	Public Awareness, Education Projects

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=CT&RE=1&EE=0

CONNECTICUT RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
CT-7	**CCEF - On-Site Renewable DG Program**	$2.5 million per project for PV projects; $4 million per project for other eligible projects (plus, potentially, a production incentive of 2¢/kWh for PV projects and 1.5¢/kWh for other eligible projects installed in southwestern CT). Minimum system capacity of 10 kW; systems must be commercially available,	Commercial, Industrial, Schools, Local Government, State Government, Institutional	Photovoltaics, Landfill Gas, Wind, Biomass, Fuel Cells, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal
CT-8	**DPUC - Capital Grants for Customer-Side Distributed Resources** (State Grant Program) (Conn. Gen. Stat. § 16-243i)	$450/kW for baseload projects ($500/kW if sited in southwestern CT and placed in operation before 4/30/2008); Max $500/kW; 65 MW maximum capacity	Commercial, Industrial, Residential, Nonprofit, Schools, Local Gov, State Gov, Fed. Gov, Agricultural, Institutional	Photovoltaics, Wind, Fuel Cells, CHP/Cogeneration, Other Distributed Generation Technologies
CT-9	**CHIF - Energy Conservation Loan** (State Loan Program) (HB 7432 (Sec. 75, 80),C.G.S. 32-315, et al.)	$400 - $25,000 (1-4 family units); $2,000 - $60,000 (multi-family of 5+ units) ; 1%, 3%, or 6% depending on income, family size, location; repayment term up to 10 years	Residential, Multi-Family Residential	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Biomass, Geothermal Heat Pumps
CT-10	**OPM - New Energy Technology Program** (Industry Recruitment/Support)	Measures must be in the prototype stage or pre-commercial stage Submit financial and progress reports to CT OPM and U.S. DOE on a quarterly basis; on-site visits by CT OPM as necessary; final report required Oil overcharge restitution funds ~$50,000 annually. Max limit: $10,000	Commercial	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Solar Pool Heating, Daylighting, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=CT&RE=1&EE=0

CONNECTICUT RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
CT-11	**Mass Energy - Renewable Energy Certificate Incentive** (Production Incentive)	$0.03/kWh toward RECs to be purchased by National Grid ratepayers; 3-year contract	Commercial, Industrial, Residential, Nonprofit, Schools, Institutional	Photovoltaics, Wind
CT-12	**Net Metering** (Conn. Gen. Stat. § 16-243h) (H.B. 7432 of 2007)	Limit on System Size: 2 MW; no limit on overall enrollment; Treatment of Net Excess: Credited to customer's next bill at retail rate; generally purchased by utility at avoided-cost rate at end of 12-month billing cycle	Commercial, Industrial, Residential, General Public/Consumer, Nonprofit, Schools, Local Government, State Government, Fed. Government, Multi-Family Residential, Agricultural, Institutional	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Fuel Cells, Municipal Solid Waste, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal
CT-13	**Renewable Portfolio Standard** (Conn. Gen. Stat. § 16-245a et seq.) (Public Act No. 07-242, Sec. 40-44)	7% by 2010; 27% by 2020	Utility, Retail Supplier	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration, Low E Renewables, Tidal Energy, Wave Energy, Ocean Thermal
CT-14	**Solar and Wind Contractor Licensing and Training** (Conn. Gen. Stat. § 20-330 et seq.)	The Connecticut Department of Consumer Protection is authorized to issue licenses for solar-thermal work, solar-electric work and wind-electric work.	Installer/Contractor, Apprentice	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics, Wind
CT-15	**Green Building Standards for State Facilities** (Conn. Gen. Stat. § 16a-38k) (HB 7432 (Sec. 10, 12, 16))	Certain state construction projects must meet standards developed by the state, based on LEED standards or Green Globes criteria.	Local Government, State Government	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Biomass, Geothermal Heat Pumps, CHP/Cogeneration, Bio-gas, Daylighting, Small Hydroelectric

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=CT&RE=1&EE=0

MASSACHUSETTS RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
MA-1	**State Income Tax Credit** (M.G.L. c. 62, sec. 6(d))	15% of the net expenditure (including installation) for the system, or $1,000, whichever is less	Residential	Solar Water Heat, Solar Space Heat, Photovoltaics, Wind
MA-2	**State Sales Tax Exemption** (M.G.L. c. 64H, sec. 6(dd))	No sales tax on purchased equipment	Residential	Solar, wind, or heat pump system
MA-3	**Local Property Tax Exemption** (M.G.L. c. 59, sec. 5, cl. 45)	Exemption from local property tax; good for 20 yrs from installation date	Residential & Commercial	Solar & wind
MA-4	**Corporate Income Tax Deduction** (M.G.L. c.63, sec. 38H)	Deduct from net income, for state tax purposes, any costs incurred from installing the unit, provided the installation is used exclusively in the trade or business of the corporation	Commercial	Qualifying solar or wind-powered "climatic control unit" or "water heating unit"
MA-5	**Alternative Energy Patent Deduction** (M.G.L. c.62, sec. 2(a)(2)(G), and c.63, sec.30 (3))	Income received from the sale, lease or other transfer of patent shall be deducted from state personal income tax or corporate excise tax for five yrs	Residential & Commercial	Solar, wind, hydroelectric
MA-6	**Hydropower-Property Tax Exemption** (M.G.L. ch.59, sec. 5, cl. (45A))	Hydropower facilities are exempt from local property tax for 20 yrs; owner agrees to pay host community at least 5% of the plants gross income for the preceding calendar year in lieu of taxes	Residential & Commercial	Hydroelectric
MA-7	**Excise Tax Deduction for Solar or Wind-Powered Systems** (MGL ch. 63, § 38H)	Businesses may deduct from net income, for state excise tax purposes, costs incurred from the installation of any "solar or wind powered climatic control unit and any solar or wind powered water heating unit or any other type unit or system powered thereby."	Commercial, Industrial	Solar Water Heat, Solar Space Heat, Solar Thermal Process Heat, Wind

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=MA03F&state=MA&CurrentPageID=1&RE=1&EE=0

MASSACHUSETTS RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
MA-8	**Excise Tax Exemption for Solar or Wind Powered Systems** (MGL ch. 63, § 38H)	100% of the tangible property portion of the excise tax (0.26% of the taxable value of the system)	Commercial, Industrial	Solar Water Heat, Solar Space Heat, Solar Thermal Process Heat, Wind
MA-9	**MTC - Business Expansion Initiative** (Business Expansion Initiative Solicitation (No. 2007-BEI-01))	$500,000 to $3,000,000 per company; Up to 50% of capital expenses and related spending over a 24-month window; at most 75% of funding can come from public sources, including equity, debt or grant.	Commercial, Industrial	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Power Inverters, Power Controls, etc., Tidal Energy, Wave Energy, Ocean Thermal, Fuel Cells using Renewable Fuels
MA-10	**MTC - Sustainable Energy Economic Development (SEED) Initiative**	Up to $500,000 per company per 12-month period. Must be a private entity based in Massachusetts that has not received private institutional equity financing; requires a 1:1 cash match	Commercial, Industrial	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Municipal Solid Waste, Power inverters, other related equipment, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal
MA-11	**Alternative Energy and Energy Conservation Patent Exemption** (Personal) (MGL ch. 62, § 2(a)(2)(G))	100% deduction Allowable for five years or until approval date set by the commissioner of energy resources	Residential	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Hydroelectric, Renewable Transportation Fuels, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste
MA-12	**Mass Energy - Renewable Energy Certificate Incentive**	$0.03 per kWh; 3-year contract	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, State Government, Fed. Government, Institutional	Photovoltaics, Wind

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=MA03F&state=MA&CurrentPageID=1&RE=1&EE=0

MASSACHUSETTS RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
MA-13	**MTC - Clean Energy Pre-Development Financing Initiative (Grants)**	Up to 50,000; Funding Source: Renewable Energy Trust Fund	Local Government, State Government, Fed. Government	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Anaerobic Digestion
MA-14	**MTC - Large Onsite Renewables Initiative (LORI) Grants**	Feasibility Grants are capped at $40,000 with an applicant cost share of 15%. Design grants are capped at the lesser of $125,000 or 75% of actual costs. Construction grants are capped at the lesser of $275,000 or 75% of actual costs. Funding Source: Massachusetts Renewable Energy Trust Fund Program	Commercial, Industrial, Schools, Local Government, State Government, Fed. Government, Multi-Family Residential, Institutional	Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Anaerobic Digestion, Renewable Fuels, Biodiesel
MA-15	**MTC - Matching Grants for Communities**	Funding Source: Renewable Energy Trust Fund Program Budget: $2.5 million in total annual funding	Local Government	Photovoltaics, Wind, Solar Lighting, Data Acquisition Equipment
MA-16	**MTC - Clean Energy Pre-Development Financing Initiative (Loans)**	Up to $250,000; Funding Source: Renewable Energy Trust Fund	Commercial, Industrial, Nonprofit, Local Gov, State Gov, Fed. Gov	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydro, Anaerobic Digestion
MA-17	**MTC - Commonwealth Solar Rebates**	$2.00 - $5.50/W DC; Up to $1.2 million per calendar year for non-residential applicants; Eligible System Size: Non-residential systems: 1 kW DC- 500 kW DC; residential systems: 1 kW DC- 5 kW DC	Commercial, Industrial, Residential, Schools, Local Government, State Government, Agricultural, Institutional	Photovoltaics
MA-18	**MTC - Small Renewables Initiative (SRI) Rebates**	$2.00/W to $6.75/W depending on technology & application; Up to $50,000 per project or site; System Size: 10 kW maximum	Commercial, Industrial, Residential, Nonprofit, Schools, Local Gov, State Gov, Fed. Gov, Multi-Family Residential, Institutional	Wind, Small Hydroelectric

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=MA03F&state=MA&CurrentPageID=1&RE=1&EE=0

NEW YORK RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
NY-1	**Green Building Tax Credit Program** (Corporate) (NY CLS Tax, Article 1 § 19)	Amount: Varies by project, distributed over 5 years Maximum Incentive:$2 million per building Carryover Provisions: Indefinite carry forward	Commercial, Construction, Multi-Family Residential	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics, Fuel Cells, Daylighting
NY-2	**NYSERDA - Clean Energy Business Growth and Development**	Amount: Varies Max. Limit: $200,000 Terms: 50% cost share	Commercial, Industrial	All Types of Renewable Electricity Generation, Daylighting
NY-3	**NYSERDA - Renewable, Clean Energy, and Energy Efficient Product Manufacturing and Incentive Program** (NY CLS Tax, Article 1, § 19)	Max. Limit: Phase I Max: lesser of 5% of project or $75,000; Phase II Max: lesser of 20% of project or $300,000; Phase III Max: up to $1,125,000, paid based on 25% of NY content of product sales over 5 years; Total: $1.5M	Commercial, Industrial	Renewable, clean energy, and electric storage products for grid-connected applications
NY-4	**NYSERDA - Renewables R&D Grant Program**	This competitive research program focuses on product and technology development as opposed to the installation of individual renewable-energy systems.	Commercial, Industrial, Residential	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Renewable Transportation Fuels, CHP/Cogeneration
NY-5	**Green Building Tax Credit Program** (Personal)	Amount: Varies by project, distributed over 5 years Maximum Incentive: $2 million per building Carryover Provisions: Indefinite carry forward	Commercial, Construction, Multi-Family Residential	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics, Fuel Cells, Daylighting
NY-6	**Solar and Fuel Cell Tax Credit** (NY CLS Tax, Article 22 § 606 (g-1) et seq.)	25% for solar-electric (PV) and solar-thermal systems; 20% for fuel cells; Up to $5,000 for solar-energy systems and $1,500 for fuel cells; Solar-electric systems - 10 kW max; Fuel cells - 25 kW max.	Residential, Multi-Family Residential	Solar Water Heat, Solar Space Heat, Photovoltaics, Fuel Cells
NY-7	**Energy Conservation Improvements Property Exemption** (RPTL §487-a)	100% of added assessed value to residence	Residential	Solar Water Heat, Photovoltaics, Wind

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=NY&RE=1&EE=0

NEW YORK RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
NY-8	**Solar, Wind & Biomass Energy Systems Exemption** (NY CLS Real Property Tax, Article 4 § 487)	15-year exemption	Commercial, Industrial, Residential, Agricultural	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Daylighting, Anaerobic Digestion
NY-9	**Solar Sales Tax Exemption** (NY CLS Tax, Article 28 § 1115 (ee))	100% Exemption	Residential	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics
NY-10	**NYSERDA - Energy $mart Loan Fund**	$20,000 for 1-4 family homes $2.5 million ($5,000/unit) for existing multi-family construction, plus an additional maximum of $2,500,000 for projects that include advanced meters; $1 million per borrower for all other non-residential facilities	Commercial, Industrial, Residential, Nonprofit, Local Gov, State Gov, Fed. Gov, Multi-Family Residential, Agricultural, Institutional, Healthcare Facility	Photovoltaics, Wind, Geothermal Heat Pumps
NY-11	**NYSERDA - Home Performance with Energy Star - Loan Program**	Up to 100% in costs; $2,500 - $20,000; 5.99% APR; fixed loan terms of 3, 5, 7 and 10 years	Residential	Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Geothermal Heat Pumps
NY-12	**NYSERDA - Energy $mart Multifamily Performance Program**	Amount varies by income eligibility and efficiency level	Multi-Family Residential, Low-Income Residential	Other Distributed Generation Technologies
NY-13	**NYSERDA - Energy $mart New Construction Program**	50-75% of incremental costs, depending of type of project; Up to $850,000 for upstate residents, and $1.65 million for Con Edison customers	Commercial, Industrial, Nonprofit, Schools, Local Government, State Government, Multi-Family Residential, Institutional	Passive Solar Space Heat, Geothermal Heat Pumps, Daylighting
NY-14	**NYSERDA - Enhanced Commercial/Industrial Performance Program**	Prescriptive rebates vary widely by equipment type and	Commercial, Industrial, Nonprofit, Schools, Local Government, State Government, Installer/Contractor, Multi-Family Residential, Agricultural, Institutional	CHP/Cogeneration

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=NY&RE=1&EE=0

NEW YORK RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
NY-15	**NYSERDA - Fuel Cell Rebate and Performance Incentive**	Amount varies by size, sector, and performance, includes capacity and performance incentives; Maximum Incentive: Small systems (<25kW): $50,000; Large systems (≥25kW): $1 million	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, Utility, State Government, Institutional	Fuel Cells
NY-16	**NYSERDA - On-Site Small Wind Incentive Program**	Amount varies by the make and model of the wind turbine, the difference between the standard tower height and the actual tower height, and the classification of the wind turbine owner; Up to $150,000 per site; 800 W - 250 kW	Commercial, Residential, General Public/Consumer, Nonprofit, Schools, Local Government, State Government, Agricultural	Wind
NY-17	**NYSERDA - Peak Load Reduction Program**	Incentives vary based on the type of load reducing measure; Up to $5 million per contractor; Up to $1.25 million per facility	General Public/Consumer	Photovoltaics, Wind, Fuel Cells, Other Distributed Generation Technologies
NY-18	**NYSERDA - PV Incentive Program**	$3-$5/W, varies by sector, installed capacity, and system type; Residential incentives are capped at 10 kW and non-residential incentives are capped at 50 kW per site/meter	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, State Government, Institutional	Photovoltaics
NY-19	**KeySpan Energy Delivery - Solar Thermal Rebate Program**	Residential: 15% of project costs, up to $1,500; Commercial/Multi-family: $3/therm based on estimated first-year savings	Commercial, Industrial, Residential, Multi-Family Residential (KeySpan Customers Only)	Solar Water Heat and Solar Pool Heating for residential customers; Also, Solar Space Heat and Solar Thermal Process Heat for commercial/industrial customers
NY-20	**Long Island Power Authority - Residential Energy Efficiency Rebate Program**	Split Central Air Conditioner: $250-$600; Air Source Heat Pump: $250-$600; Geothermal Heat Pump: $200 - $1,000/unit, Clothes Washer: $50; Dehumidifier: $10; Cold Cathode Lights: $2.00/pack; CFLs: $2.00/pack; High Heat Reflector Lamp: $2.50/pack	Residential	Geothermal Heat Pumps

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=NY&RE=1&EE=0

NEW YORK RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
NY-21	**Long Island Power Authority - Solar Pioneer Program**	Residential and Commercial: $3.50/watt DC; Schools, Nonprofits, Government agencies: $4.50/watt DC; 10 kW max size	Commercial, Residential, Nonprofit, Schools, Local Government, State Government	Photovoltaics
NY-22	**New York City - Green Building Requirements for Municipal Buildings**	City funded new construction or substantial reconstruction projects >$2 million must meet LEED Silver Certification standards; Schools and hospitals must meet LEED Certification	Local Government	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Photovoltaics, Wind, Biomass, Daylighting, Small Hydroelectric
NY-23	**Environmental Disclosure Program**	Fuel Mix: Renewable Energy Resources, Coal, Natural Gas, Oil, Nuclear; Emissions:SO2, NOx, CO2; Distributed twice/yr	Utility	Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Municipal Solid Waste
NY-24	**New York - Renewable Power Procurement Policy** (Executive Order No. 111) (Executive Order No. 111 Guidelines)	10% by 2005; 20% by 2010	State Government	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Fuel Cells, Other Methane Waste, Tidal Energy
NY-25	**Interconnection Standards** (NY PSC Order, Case 94-E-0952) (NY PSC Order, Case 02-E-1282) (New York Standard Interconnection Requirements)	Limit on System Size/Overall Enrollment: 2 MW;	Commercial, Industrial, Residential, Agricultural	Solar Thermal Electric, PV, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration, Microturbines, Other Distributed Generation Technologies
NY-26	**New York - Net Metering** (NY CLS Public Service, Article 4 § 66-j and § 66-l)	Limit on System Size: 10 kW for solar; 25 kW for residential wind; 125 kW for farm-based wind; 400 kW for farm-based biogas; Limit on Overall Enrollment: 0.1% of 1996 demand per IOU for solar; 0.2% of 2003 demand per IOU for wind; 0.4% of 1996 demand per IOU for farm-based biogas; Net Excess: Credited to customer's next bill at utility's retail rate.	Residential, Agricultural	Photovoltaics, Wind, Biomass

Source: Database for State Incentives for Renewables & Efficiency
http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=NY&RE=1&EE=0

NEW YORK RENEWABLE INCENTIVE PROGRAMS

Ref #	Incentive & Authority	Details	Sector/s	Renewables
NY-27	**System Benefits Charge** (NY PSC Opinion No. 96-12 (Cases 94-E-0952 et al.)) (NY PSC Order (Case 94-E-0952)) (NY PSC Order (Case 05-M-0090))	Total Fund: $1.86 billion through 2011; Charge: Each utility must collect a sum equal to 1.42% of its 2004 revenue and submit this sum to NYSERDA annually.	Commercial, Industrial, Residential, General Public/Consumer, Utility, Institutional	Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, CHP/Cogeneration, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Ethanol, Methanol, Biodiesel
NY-28	**LIPA - Renewable Electricity Goal** (LIPA 2004-2013 Energy Plan)	Long Island Power Authority will voluntarily comply with the state requirement that 24% of electricity generation come from renewable resources by 2013.	Utility	Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Ethanol, Methanol, Biodiesel
NY-29	**Renewable Portfolio Standard** (NY PSC Order, Case 03-E-0188) (NY PSC Order, Case 03-E-0188)	24% by 2013; Technology Minimum: 2% of total incremental RPS requirement is set-aside for the Customer-Sited Tier, for a total of 0.1542% of customer-sited generation	Investor-Owned Utility	Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Fuel Cells, Anaerobic Digestion, Tidal Energy, Wave Energy, Ocean Thermal, Ethanol, Methanol, Biodiesel
NY-30	**Solar Easements** (NY CLS Real Property, Article 9 § 335-b) (NY CLS General City, Article 2-A § 20 (24))	voluntary contracts which must be entered into in order to ensure uninterrupted solar access for solar energy devices	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, State Government, Fed. Government	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics

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