Path to Prosperity

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The Economic Impact of Maine's Renewable Portfolio Standard

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The state of Maine is a pioneer in passing Renewable Portfolio Standard (RPS) legislation. First implemented in 1999, the law required that 30 percent of total retail electric sales in the state come from renewable sources.[1] The law itself did not actually alter the state's mix of fuel sources used for electricity production, to the chagrin of proponents. Maine was already producing large quantities of energy from renewable sources. Maine's numerous lakes and streams enabled the production of economically viable hydroelectric power, and its forestry industry supplied wood waste for biomass electricity production.

In June 2006, then-Governor John Baldacci signed legislation to counter the perception that the RPS law lacked environmental benefits. The new goal: Increase the amount of *new* renewable energy to 10 percent by 2017, with annual increases of one percent beginning in 2008 until the goal is reached.[2] Since these "Class I standards" consider only small generation plants reaching service after September 2005, the law will affect the fuel mix of Maine's power industry.

The Beacon Hill Institute applied its STAMP® (State Tax Analysis Modeling Program) to estimate the economic effects of these RPS mandates. The U.S. Energy Information Administration (EIA), a division of the Department of Energy, provides optimistic estimates of renewable electricity costs and capacity factors. We base our estimates on EIA projections, but we also provide three estimates of the cost of Maine's RPS mandates – low, average and high – using different cost and capacity factor estimates for electricity-generating technologies from the academic literature. Our major findings show:

- The Maine RPS law will raise the cost of electricity by $145 million for the state's consumers in 2017, within a low-range estimate of $120 million and a high-range estimate of $175 million
- Maine's electricity prices will rise by 8 percent by 2017, due to the RPS law.

The increased energy prices will hurt Maine's households and businesses and, in turn, inflict significant harm on the state economy. In 2017, the RPS will:

- Lower employment by an average of 995 jobs, within a range of 820 jobs and 1,165 jobs
- Reduce real disposable income by $85 million, within a range of $70 million and $100 million
- Decrease investment by $11 million, within a range of $9 million and $13 million
- Increase the average household electricity bill by $80 per year; commercial businesses by an average of $615 per year; and industrial businesses by an average of $14,350 per year.

Introduction

Maine has two different sets of Renewable Portfolio Standard (RPS) laws. The first went into effect in 1999 and, in effect, codified the existing 30 percent of retail energy derived from renewable sources. Maine's abundant natural resources provided ample and cost-effective resources to produce renewable electricity.[3] Many small and efficient hydroelectric plants produced low cost energy at the same time electric utilities burned wood waste and other biomass byproducts. The 30 percent mandate had minor, if any, effect on the energy market in Maine.

The second, more recent RPS law, commonly referred to as the Class I standards, does not mandate a share of total production for renewables, like many state RPS laws. Instead, the law mandates that from 2017 onward, at least 10 percent of total retail electricity sales must be generated from *new* renewable sources.[4] The law requires that beginning in 2008 at least one percent of electricity must be from renewable generation plants reaching service after September 2005, increasing one percent each year until 2017.

Another component of the law – the use of Generation Information Systems certificates (GIS) – could help defray costs. GISs are similar to Renewable Energy Credits (REC), which account for production of renewable energy and are equivalent to one kilowatt hour of renewable production. RECs are tradable commodities that are certified to represent a unit of production of renewable energy. The GISs may only be banked for one year, so the actual cost effect will be minimal in subsequent years if electric utilities fail to exceed the mandate for the previous year.

By producing more renewable energy than required by the law, energy suppliers could bank credits to reduce future requirements. However, the Energy Information Administration (EIA) projections made prior to the law show a baseline scenario in which renewable electricity generations will fall below RPS minimums. Therefore, it is unlikely that producers will supply excess renewable energy to trigger significant banking. All renewable energy produced will go toward the requirement that year, not banked for future consumption. For this reason, we assume that the GIS certificates will have no effect on overall price of production.

Additionally, the law implements an Alternative Compliance Payment (ACP) that Utilities can pay instead of producing renewable energy. The ACP rate grows at the speed of inflation, and is currently set at $62.10 per MWh.[5] Historically the ACP has not played much part in meeting the RPS for any utilities. The amount of money spent on ACPs has declined from $690,000 in 2008 to $20,000, or 0.3 percent of compliance costs, in 2010.[6] To calculate the true cost of the RPS law, we assume that the ACP will continue to play an insignificant role.

Since renewable energy generally costs more than conventional energy, many have voiced concerns about higher electric rates. A wide variety of cost estimates exists for renewable electricity sources. The EIA provides estimates for the cost of conventional and renewable electricity generating technologies. However, the EIA's assumptions are optimistic regarding the cost and capacity of renewable electricity generating sources to produce reliable energy.

A review of the literature shows that in most cases the EIA's projected costs can be found at the low end of the range of estimates, while the EIA's capacity factor for wind to be at the high end of the range. The EIA does not take into account the actual experience of existing renewable electricity power plants. Therefore we provide three estimates of the cost of Maine's RPS mandate: low, average and high, using different cost and capacity factor estimates for electricity-generating technologies from the academic literature.

Governments enact RPS policies because most sources of renewable electricity generation are less efficient and thus more costly than conventional sources of generation. The RPS policy forces utilities to buy electricity from renewable sources and thus guarantees a market for them. These higher costs are passed on to electricity consumers, including residential, commercial and industrial customers.

Increases in electricity costs are known to have a profound negative effect on the economy – not unlike taxes – as prosperity and economic growth are dependent upon access to reliable and affordable energy. Since electricity is an essential commodity, consumers will have limited opportunity to avoid these costs. For the poorest members of society, these energy taxes will compete directly with essential purchases in the household budget, such as food, transportation and shelter.

The Maine Heritage Policy Center and The Beacon Hill Institute at Suffolk University (BHI) estimates the costs of this RPS law and its impact on the state's economy. To that end, BHI applied its STAMP® (State Tax Analysis Modeling Program) to estimate the economic effects of the state RPS mandate.[7]

Estimates and Results

We estimate of the effects of Maine's Class I RPS mandate using low, average and high cost scenarios of both renewable and conventional generation technologies. Each estimate represents the change that will take place in the indicated variable against the counterfactual assumption, or baseline, that the Class I mandate would not be in place. The Appendix contains details of our methodology. Table 1 displays the cost estimates and economic impact of the current RPS mandate in 2017, compared to a baseline.

Table 1: The Cost of the RPS Mandate on Maine (2012 $)

Costs Estimates	**Low**	**Average**	**High**
Total Net Cost in 2017 ($ m)	120	145	175
Total net cost 2012-2017 ($ m)	535	655	775
Electricity Price Increase in 2020 (cents per kWh)	1.01	1.24	1.46
Percentage Increase (%)	6.6	8.0	9.5
Economic Indicators			
Total Employment (jobs)	-820	-995	-1,165
Investment ($ m)	-9	-11	-13
Real Disposable Income ($ m)	-70	-85	-100

The current RPS will impose costs of $145 million in 2017, within a range of $120 million and $175 million. Over the entire period between 2012 and 2017, the RPS will cost Maine $655 million within a range of $535 million and $775 million. As a result, the RPS mandate would increase electricity prices by 1.24 cents per kilowatt hour (kWh) or by 8 percent, within a range of 1.01 cents per kWh, or by 6.6 percent, and 1.46 cents per kWh, or by 9.5 percent.[8]

The STAMP model simulation indicates that, upon full implementation, the electricity price increases due to the RPS law will negatively affect the Maine economy. The state's ratepayers will face higher electricity prices that will increase their costs, which will in turn put downward pressure on household and business income. By 2017 the Maine economy will shed 995 jobs, within a range of estimates of 820 and 1,165 jobs.

The job losses and price increases will reduce real incomes as firms, households and governments spend more of their budgets on electricity and less on other items, such as home goods and services. In 2017, real disposable income will fall by an average of $85 million, between $70 million and $100 million under the low and high cost scenarios respectively. Furthermore, net investment will fall by $11 million, within a range of $9 million and $13 million.

Table 2 shows how the RPS mandate affects the annual electricity bills of households and businesses in Maine. In 2017, the RPS will cost families an average of $85 per year; commercial businesses $615 per year; and industrial businesses $14,350 per year. Between 2012 and 2017, the average residential consumer can expect to pay $365 more for electricity, while a commercial ratepayer would pay $2,715 more and the typical industrial user would pay $63,305 more.

Table 2: Annual Effects of RPS on Electricity Ratepayers (2012 $)

	Low	Medium	High
Cost in 2017			
Residential Ratepayer ($)	70	85	100
Commercial Ratepayer ($)	505	615	725
Industrial Ratepayer ($)	11,745	14,350	16,955
Total over period (2012-2017)			
Residential Ratepayer ($)	300	365	430
Commercial Ratepayer ($)	2,220	2,715	3,205
Industrial Ratepayer ($)	51,765	63,305	74,845

Emissions: Life Cycle Analysis

One could justify the higher electricity costs if the environmental benefits – in terms of reduced greenhouse gases (GHG) and other emissions – outweighed the costs. In the previous sections we calculated and displayed the costs and economic effects to require more renewable energy in the state of Maine. The following section conducts a Life Cycle Analysis (LCA) of renewable energy and the total effect that the state Class I RPS law is likely to have on Maine's emissions.

The burning of fossil fuels to generate electricity produces emission of gases as waste, such as carbon dioxide (CO_2), sulfur oxides (SO_x) and nitrogen oxides (NO_x). These gases are found to negatively affect human respiratory health and the environment (SO_x and NO_x) or said to contribute to global warming (NO_x and CO_2).

Many proponents of renewable energy, such as wind power, solar power and municipal solid waste (MSW) justify the higher electricity prices, and the negative economic effects that follow, based on the claim that these sources produce no emissions (see examples below). But this is misleading. The fuel that powers these services -- such as the sun and wind – create no emissions. However, the process of construction, operation and decommissioning of renewable power plants does create emissions. This begs the question: Is this renewable energy production as environmentally friendly as some proponents claim?

> "Harnessing the wind is one of the cleanest, most sustainable ways to generate electricity. Wind power produces no toxic emissions and none of the heat trapping emissions that contribute to global warming."[9]

"Wind turbines harness air currents and convert them to emissions-free power."[10]
~Union of Concerned Scientists

"As far as pollution…Zip, Zilch, Nada… etc. Carbon dioxide pollution isn't in the vocabulary of solar energy. No emissions, greenhouse gases, etc."[11]
~Let's Be Grid Free. Solar Energy Facts

The affirmative argument is usually based on the environmental effects of the operational phase of the renewable source (that will produce electricity with no consumption of fossil fuel and no emissions) excluding the whole manufacturing phase (from the extraction to the erection of the turbine or solar panel, including the production processes and all the transportation needs) and the decommission phase. LCA provides a framework to provide a more complete answer the question.

LCA is a "cradle-to-grave" approach for assessing industrial systems. LCA begins with the gathering of raw materials from the earth to create the product and ends at the point when all materials are returned to the earth. By including the impacts throughout the product life cycle, LCA provides a comprehensive view of the environmental aspects of the product or process and a more accurate picture of the true environmental trade-offs in product and process selection. Table 3 displays LCA results for conventional and renewable sources.

Table 3: Emissions by Source of Electricity Generation (Grams/kWh)

Phase	Emission	Coal	Gas	Wind	Nuclear	Solar	Biomass
Construction and Decommission	CO_2	2.59	2.20	6.84	2.65	31.14	0.61
	NO_x	0.01	0.01	0.06	0.00	0.12	0.00
	SO_x	0.06	0.05	0.02	0.00	0.14	0.00
Production and Operation	CO_2	1,022.00	437.80	0.39	1.84	0.27	58.60
	NO_x	3.35	0.56	0.00	0.00	0.02	5.34
	SO_x	6.70	0.27	0.00	0.01	0.00	2.40
Total	CO_2	1,024.59	440.00	7.23	4.49	31.42	59.21
	SO_x	3.36	0.57	0.06	0.01	0.14	5.34
	NO_x	6.76	0.32	0.02	0.01	0.14	2.40

Coal and gas produce significantly more emissions of all three gases than all the other technologies. Nuclear and wind produce the least emissions of the nonconventional types, with solar and biomass significantly higher due to construction and decommission for solar and production and operations for biomass. However, the construction and decommission phases of wind and solar produce non trivial levels of emissions, with solar several factors higher than the others. Nevertheless, LCA analysis shows that wind, nuclear, solar and biomass produce significantly less emissions than coal and gas.

However, this LCA analysis is incomplete. The analysis shows that wind and solar technologies derive benefits from their ability to produce electricity with no consumption of fossil fuels and subsequent pollution without adequately addressing the intermittency of these technologies. These intermittent technologies cannot be dispatched at will and, as a result, require reliable back-up generation running – idling – in order to keep the voltage of the electricity grid in equilibrium. For example if the wind ceases, or blows too hard (which trips a shutdown mechanism in commercial windmills), another power source must be ramped up (or cycled) instantaneously. Therefore new wind and solar generation plants do not replace any dispatchable generation sources.

This cycling of coal and (to a much lesser extent) gas plants causes them to run inefficiently and produce more emissions than if the intermittent technologies were not present. As a result – according to a recent study – wind power could actually increase pollution and greenhouse gas emissions in areas that generate a significant portion of their electricity from coal.[12] The current LCA literature ignores this important portion of the analysis, which provides a distorted assessment of wind and solar power.

Nevertheless, even incorporating renewable sources does, in and of themselves, produce much less emissions than conventional sources renewable sources, displacing only a small amount of emissions from conventional sources. Indeed this amount is multiplied, due to lower capacity ratings of many green energy sources and required back-up generation.

To better judge the actual total benefit derived from switching from the current energy source portfolio to one that involves more renewable energy – as the RPS dictates in Maine – BHI compared the total emissions impact according to our projections using a life cycle analysis for the various energy sources. Table 4 displays the results.

Table 4: Change in Emissions Due to the Maine RPS Mandates ('000 metric tons)

Emission Gas	2017	Total 2012-2017
No Capacity Factor Differences		
Carbon Dioxide	-487	-2,174
Sulfur Oxide	4	18
Nitrogen Oxide	2	7
Capacity Factor Differences		
Carbon Dioxide	-163	-728
Sulfur Oxide	5	20
Nitrogen Oxide	2	9

The results are somewhat counterintuitive. The RPS mandates reduce emissions of CO_2 by 163,000 metric tons in 2017, with a total reduction compared to baseline of 728,000 tons between 2012 and 2017. If no back up capacity was required due to the intermittency issues of renewables, then the reduction would be more than three times as much. Surprisingly, SO_x and NO_x emissions show a slight increase compared to a baseline in all years. The reason for this is that biomass and wood waste – two large sources of renewable energy in Maine – emit large amounts of these two types of particulate matter.

Conclusion

Proponents of renewable energy in Maine were disappointed with the outcome of the first RPS laws in Maine. In effect it made legal requirements and consequences for what was already taking place in Maine. Where it was cost efficient, renewable energy was growing in Maine. But that was not enough for renewable energy advocates. In this paper we reviewed the implications of a new RPS law that began in 2008. This version, commonly referred to as Class I requirements, required that 10 percent of energy come from *new* renewable sources by 2017.

The most recent Maine Public Utilities Commission review of the RPS states:

> "Assuming half of the wind generation proposed in the Interconnection Queue for Maine is developed over time (625 MW installed capacity) at a total investment cost of more than $2,000/KW at that and that 35 percent of the capital costs are spent in Maine this could result in approximately $560 million of investment in Maine. This level of investment will result in a roughly ($1.14 billion) increase in GSP and 11,700 jobs created during construction."[13]

This thinking – that the higher the cost of renewable technologies rise, the more investment and jobs the technologies create – is dangerous. For example, if investment cost rose to $4,000 per KW, then the resulting investment would rise to $1.12 billion and state GSP would rise by some derivative of $2.28 billion and job creation by 23,400. But what would that increase in investment cost mean for the price of wind energy that Maine's households and business are mandated to purchase? The price would rise and hurt the state's electricity consumers. Moreover, the investment spending has an opportunity cost in terms of the industries that might have received this investment in the absence of the RPS mandates.

Supporters of the Maine RPS use a hidden tax approach, with the quote above showing they fail to undertake any reasonable cost-benefit analysis backed up by economic reasoning. The Maine RPS puts the state's robust competitiveness at risk. While the RPS may generate economic benefits, Maine electricity ratepayers will pay higher rates, face fewer employment opportunities, and watch investment flee to other states with more favorable business climates, resulting in net negative effects on the state.

Firms with high electricity usage will likely move their production, and emissions, out of Maine to locations with lower electricity prices. Therefore, the Maine policy will not reduce global emissions, but rather send jobs and capital investment outside the state.

Appendix

Electricity Generation Costs

As noted above, governments enact RPS policies because most sources of renewable electricity generation are less efficient and thus more costly than conventional sources of generation. RPS policies force utilities to buy electricity from renewable sources and thus guarantee a market for the renewable sources. These higher costs are passed to electricity consumers, including residential, commercial and industrial customers.

The EIA estimates the Levelized Energy Cost (LEC), or financial breakeven cost per MWh, to produce new electricity in its *Annual Energy Outlook*.[14] The EIA provides LEC estimates for conventional and renewable electricity technologies (coal, nuclear geothermal, landfill gas, solar photovoltaic, wind and biomass) assuming the new sources enter service in 2016. The EIA also provides LEC estimates for conventional coal, combined cycle gas, advanced nuclear and onshore wind only, assuming the sources enter service in 2020 and 2035.

While the EIA does not provide LEC for hydroelectric, solar photovoltaic and biomass for 2020 and 2035, it does project overnight capital costs for 2015, 2025 and 2035. We can estimate the LEC for these technologies and years using the percent change in capital costs to inflate the 2016 LECs. In its *Annual Energy Outlook*, the EIA incorporates many assumptions about the future price of capital, materials, fossil fuels, maintenance and capacity factor into their forecast. Table 5 shows the EIA projects that the LEC for all four electricity sources (coal, gas, nuclear and wind) will fall significantly from 2016 to 2035. The fall in capital costs drives the drop in total system LEC over the period.

Using the EIA change in overnight capital costs for solar and biomass produces reductions in LECs similar to wind from 2016 to 2035. The biomass LEC drops by 38.7 percent and solar by 53.5 percent over the period. These compare to much more modest cost reductions of 5.2 percent for coal, an increase of 14.2 percent for gas, and a drop of 22.1 percent for nuclear over the same period. EIA does provide overnight capital costs for renewable technologies under a "high cost" scenario. However, for each renewable technology the EIA "high cost" scenario projects capital costs to drop between 2015 and 2035.

Table 5 displays capacity factors for each technology. The capacity factors measure the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period. In this case, capacity factor measures the potential productivity of the generating technology. Solar, wind and hydroelectricity have the lowest capacity factors due to the intermittent nature of their power sources. EIA projects a 34.4 percent capacity factor for wind power, which, as we will see below, appears to be at the high end of any range of estimates for the nation.

Estimating a capacity factor for wind power is particularly challenging. Wind is not only intermittent but its variation is unpredictable, making it impossible to dispatch to the grid with any certainty. This unique aspect of wind power argues for a capacity factor rating of close to zero. Nevertheless, wind capacity factors have been estimated to be between 20 percent and 40 percent.[15] The other variables that affect the capacity factor of wind are the quality and consistency of the wind and the size and technology of the wind turbines deployed. As the U.S. and other countries add more wind power over time, presumably the wind turbine technology will improve, but the new locations for power plants will likely have less productive wind resources.

The EIA estimates of LEC and capacity factors paint a particularly rosy view of the future cost of renewable electricity generation, particularly wind. Other forecasters and the experience of current renewable energy projects portray a less sanguine outlook.

Today wind and biomass are the largest renewable power sources and are the most likely to satisfy future RPS mandates. The most prominent issues that will affect the future availability and cost of renewable electricity resources are diminishing marginal returns and competition for scarce resources. These issues will affect wind and biomass in different ways as state RPS mandates ratchet up over the next decade.

Both wind and biomass resources face land use issues. Conventional energy plants can be built within a space of several acres, but a wind power plant with the same nameplate capacity (not actual capacity) would require many square miles of land. According to one study, wind power would require 7,579 miles of mountain ridgeline to satisfy current state RPS mandates and a 20 percent federal mandate by 2025.[16] Mountain ridgelines produce the most promising locations for electric wind production in the eastern and far western United States.

After taking into account capacity factors, a wind power plant would need a land mass of 20 by 25 kilometers to produce the same energy as a nuclear power plant that can be situated on 500 square meters.[17]

Table 5: Levelized Cost of Electricity from Conventional and Renewable Sources (2009 $)

Plant Type	Capacity Factor	Levelized Capital Costs	Fixed O&M	Variable O&M (with fuel)	Transmission Investment	Total Levelized Cost
Advanced Coal - 2016	0.85	65.3	3.9	24.3	1.2	94.8
2020		75.84	7.9	25.1	1.2	110.0
2035		55.4	7.9	25.4	1.19	89.8
Gas - 2016	0.87	17.5	1.9	45.6	1.2	66.1
2020		18.4	1.89	46.7	1.2	68.2
2035		13.5	1.89	59.0	1.2	75.5
Nuclear -2016	0.9	90.1	11.1	11.7	1	113.9
2020		89.1	11.1	12.3	1	113.5
2035		62.3	11.1	14.3	1	88.7
Wind - 2016	.344	83.9	9.6	0	3.5	97.0
2020		86.4	9.5	0	3.4	99.2
2035		71.4	9.9	0	3.6	84.9
Solar PV - 2016	0.217	194.6	12.1	0	4	210.7
2025						142.0
2035						98.0
Biomass -2016	0.83	55.3	13.7	42.3	1.3	112.5
2025						88.0
2035						69.0
Hydro -2016	0.514	74.5	3.8	6.3	1.9	86.4
2025						69.0
2035						55.0

The need for large areas of land to site wind power plants will require the purchase of vast areas of land by private wind developers, and/or allowing wind production on public lands. In either case land acquisition/rent or public permitting processes will likely increase costs as wind power plants are built. Offshore wind is vastly more expensive than onshore wind power and suffers from the same type of permitting process faced by onshore wind power plants, as seen in the 10-year permitting process for the planned Cape Wind project off the coast of Massachusetts.

The swift expansion of wind power will also suffer from diminishing marginal returns as new wind capacity will be located in areas with lower and less consistent wind speeds. As a result, fewer megawatt hours of power will be produced from newly built wind projects. Moreover the new wind capacity will be developed in increasingly remote areas that will require larger investments in transmission and distribution, which will drive costs even higher.

The EIA estimates of the average capacity factor used for onshore wind power plants, at 34.4 percent, appears to be at the higher end of the estimates for current wind projects. This figure is inconsistent with estimates from other studies.[18] According to the EIA's own reporting from 137 current wind power plants in 2003, the average capacity factor was 26.9 percent.[19] In addition, a recent analysis of wind capacity factors around the world finds an actual average capacity factor of 21 percent.[20] Moreover, other estimates find capacity factors in the mid-teens and as low as 13 percent.[21]

Biomass is a more promising renewable power source. Biomass combines low incremental costs relative to other renewable technologies and reliability. Biomass is not intermittent and therefore it is distributable with a capacity factor that is competitive with conventional energy sources. Moreover biomass plants can be located close to urban areas with high electricity demand. But biomass electricity suffers from land use issues even more so than wind.

The expansion of biomass power plants will require huge additional sources of fuel. Wood and wood waste comprise the largest source of biomass energy today. Other sources of biomass include food crops, grassy and woody plants, residues from agriculture or forestry, oil-rich algae, and the organic component of municipal and industrial wastes.[22] Biomass power plants will compete directly with other sectors (construction, paper, furniture) of the economy for wood and food products and arable land.

One study estimates that 66 million acres of land would be required to provide enough fuel to satisfy the current state RPS mandates and a 20 percent federal RPS in 2025.[23] When the clearing of new farm and forestlands are figured into the GHG production of biomass, it is likely that biomass increases GHG emissions.

The competition for farm and forestry resources would not only cause biomass fuel prices to skyrocket, but also cause the prices of domestically-produced food, lumber, furniture and other products to rise. The recent experience of ethanol and its role in surging corn prices can be casually linked to the recent food riots in Mexico, and also to the struggle facing international aid organizations that address hunger in places such as the Darfur region of Sudan. These two examples serve as reminders of the unintended consequences of government mandates for biofuels. The lesson is clear: biofuels compete with food production and other basic products, and distort the market.

Calculation of the Net Cost of New Renewable Electricity

To calculate the cost of renewable energy under the RPS, BHI used data from the EIA to determine the percent increase in utility costs that Maine residents and businesses would experience. This calculated percent change was then applied to calculated elasticities, as described in the STAMP modeling section.

In our cost analysis we only reviewed the costs for the Class I standards. Class II standards, we assumed, would have little or no cost due to the base line scenario already covering the requirements. To determine that cost of the Class I standards, we used EIA projections to determine the total retail sales into the future. Since the Class I standards require new renewable energy, we assumed that these are generation sources that would not have been created in a baseline scenario. So we multiplied the requirement percentage by the baseline scenario, and the resulting figure was the amount of MWhs that the state needs to add to meet the RPS requirements. This figure also represents the maximum number of MWhs of electricity from conventional sources that are avoided, or not generated, through the RPS mandate. We will revisit this shortly. Table 6, as follows, contains the results.

Table 6: Projected Electricity Demand and RPS Requirements

Year	Projected Electricity Demand MWhs (000s)	RPS Requirement MWhs (000s)
2012	11,626	581
2013	11,679	700
2014	11,735	821
2015	11,794	944
2016	11,857	1,067
2017	11,923	1,192
Total	**70,614**	**5,306**

To estimate the cost of producing the additional extra renewable energy under an RPS against the baseline, we used estimates of the LEC, or financial breakeven cost per MWh, to produce the electricity.[24] However as outlined in the "electricity generation cost" section above, the EIA numbers provide a rather optimistic picture of the cost and generating capacity of renewable electricity, particularly for wind power. A literature review provided alternative LEC estimates that were generally higher and capacity factors that were lower for renewable generation technologies than the EIA estimates.[25] We used these alternative figures to calculate our "high" LEC estimates and the EIA figures to calculate our "low" cost estimates and the average of the two to calculate our "average" cost estimates. Table 7 below displays the LEC and capacity factors for each generation technology.

We used the 2016 LEC for the years 2010 through 2018 to calculate the cost of the new renewable electricity and avoided conventional electricity, assuming that before 2016 LEC underestimates the actual costs for those years and for 2017 and 2018, the 2016 LEC slightly overestimates the actual costs. We assumed that the differences will, on balance, offset each other. For 2019 and 2020 we used the 2020 LEC. The assumption is that LEC will decline over time due to technological improvements over time.

We used the EIA's reference case scenario for all technologies. Since capital costs represent the large component of the cost structure for most technologies, we used the percentage change in the capital costs from 2015 to 2025 to adjust the 2016 LECs to 2025. For the technologies that the EIA does not forecast LECs in 2020, we used the average of the 2016 and 2025 LEC calculations, assuming a linear change over the period.

Once we computed new LECs for the years 2020 and 2025 we applied these figures to the renewable energy estimates for the remainder of the period.

For conventional electricity we assumed that the technologies are avoided based on their costs, with the highest cost combustion turbine avoided first. For coal and gas, we assumed they are avoided based on their estimated proportion of total electric sales for each year. Although hydroelectric and nuclear are not the cheapest technology,

Table 7: LEC and Capacity Factors for Electricity Generation Technologies

	Capacity Factor (percent)	Total Production Cost (cents/MWh) 2016	2020	2025
Coal				
Low	74.0	67.41	64.82	63.53
Average	79.5	81.11	87.43	81.72
High	85.0	94.80	110.03	99.91
Gas				
Low	85.0	66.10	68.17	71.84
Average	86.0	70.98	70.71	72.54
High	87.0	75.86	73.25	73.25
Nuclear				
Low	90.0	76.94	59.20	49.33
Average	90.0	95.42	86.36	75.22
High	90.0	113.90	113.52	101.12
Biomass				
Low	68.0	112.50	100.07	87.63
Average	75.5	112.50	101.80	93.00
High	83.0	113.90	103.54	98.36
Wind				
Low	34.4	97.00	99.22	92.04
Average	15.5	192.34	184.38	171.72
High	26.9	287.67	269.54	251.40

we assumed no hydroelectric or nuclear sources are displaced since most were built decades ago and offer relatively cheap and clean electricity today.

We also adjusted the avoided cost of conventional energy to account for the lower capacity factor of wind relative to conventional energy sources. We multiplied the cost of each conventional energy source by the difference between its capacity factor and the capacity factor for the renewable source and then by the ratio of the new generation of the renewable source to the total new generation of renewable under the RES. With coal, for example, we multiplied the avoided amount generation of electricity from coal (3.41 million MWhs in 2020) by the LEC of coal ($85.21 per MWh) and then by the difference between the capacity factor of coal and the weighted average (using MWs as weights) capacity factor of wind (37.4 percent). This process is repeated for each conventional electricity resource.

These LECs are applied to the amount of electricity supplied from renewable sources under the RES, because this figure represents the amount of conventional electricity generation capacity that presumably will not be needed under the RES. The difference between the cost of the new renewable sources and the costs of the conventional electricity generation Maine represents the net cost of the RPS. Tables 8, 9 and 10 on the following pages display the results of our Average, Low and High Cost calculations for the RPS, respectively.

We converted the aggregate cost of the RPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, for 2017 under the average cost scenario above, we divided $147 million into 11,923 million kWhs for a cost of 1.24 cents per kWh.

Table 8: Average Cost Case RPS Mandate from 2012 to 2017

Year	Gross Cost (2012 $000s)	Less Conventional (2012 $000s)	Total (2012 $000s)
2012	75,775	3,957	71,818
2013	91,816	4,933	86,883
2014	107,612	5,768	101,844
2015	122,954	6,398	116,555
2016	139,273	7,309	131,964
2017	155,614	8,163	147,451
Total	**693,044**	**36,529**	**656,515**

Table 9: Low Cost Case RPS Mandate from 2012 to 2017

Year	Gross Cost (2012 $000s)	Less Conventional (2012 $000s)	Total (2012 $000s)
2012	62,650	3,781	58,870
2013	75,436	4,708	70,728
2014	88,434	5,500	82,934
2015	101,693	6,101	95,592
2016	114,978	6,969	108,009
2017	128,471	7,782	120,689
Total	**571,663**	**34,841**	**536,822**

Table 10: High Cost Case of a RPS Mandate from 2012 to 2017

Year	Gross Cost (2012 $000s)	Less Conventional (2012 $000s)	Total (2012 $000s)
2012	88,899	4,135	84,765
2013	108,196	5,160	103,036
2014	126,790	6,036	120,753
2015	144,215	6,697	137,518
2016	163,568	7,650	155,918
2017	182,758	8,545	174,213
Total	**814,426**	**38,222**	**776,204**

Ratepayer Effects

To calculate the effect of the RPS on electricity ratepayers we used EIA data on the average monthly electricity consumption by type of customer: residential, commercial and industrial.[26] The monthly figures were multiplied by 12 to compute an annual figure. We inflated the 2010 figures for each year using the average annual increase in electricity sales over the entire period.[27]

We calculated an annual per-kWh increase in electricity cost by dividing the total cost increase – calculated in the section above – by the total electricity sales for each year. We multiplied the per-kWh increase in electricity costs by the annual kWh consumption for each type of ratepayer for each year. For example, we expect the average residential ratepayer to consume 6,691 kWhs of electricity in 2017 and we expect the average cost scenario to raise electricity costs by 1.24 cents per kWh in the same year. Therefore we expect residential ratepayers to pay an additional $83 in 2020.

Modeling the RPS using STAMP

We simulated these changes in the STAMP model as a percentage price increase on electricity to measure the dynamic effects on the state economy. The model provides estimates of the proposals' impact on employment, wages and income. Each estimate represents the change that would take place in the indicated variable against a "baseline" assumption of the value that variable for a specified year in the absence of the RPS policy.

Because the RPS requires Maine households and firms to use more expensive "green" power than they otherwise would have under a baseline scenario, the cost of goods and services will increase under the RES. These costs would typically manifest through higher utility bills for all sectors of the economy. For this reason we selected the sales tax as the most fitting way to assess the impact of the RES. Standard economic theory shows that a price increase of a good or service leads to a decrease in overall consumption, and consequently a decrease in the production of that good or service. As producer output falls, the decrease in production results in a lower demand for capital and labor.

BHI utilized its STAMP (State Tax Analysis Modeling Program) model to identify the economic effects and to understand how they operate through a state's economy. STAMP is a five-year dynamic CGE (computable general equilibrium) model that has been programmed to simulate changes in taxes, costs (general and sector-specific) and other economic inputs. As such, it provides a mathematical description of the economic relationships among producers, households, governments and the rest of the world. It is general in the sense that it takes all the important markets, such as the capital and labor markets, and flows into account. It is an equilibrium model because it assumes that demand equals supply in every market (goods and services, labor and capital). This equilibrium is achieved by allowing prices to adjust within the model. It is computable because it can be used to generate numeric solutions to concrete policy and tax changes.[28]

In order to estimate the economic effects of a national RPS we used a compilation of six STAMP models to garner the average effects across various state economies: New York, North Carolina, Washington, Kansas, Indiana and Pennsylvania. These models represent a wide variety in terms of geographic dispersion (northeast, southeast, midwest, the plains and west), economic structure (industrial, high-tech, service and agricultural), and electricity sector makeup.

First we computed the percentage change to electricity prices as a result of three different possible RPS policies.

We used data from the EIA from the state electricity profiles, which contains historical data from 1990-2008 for retail sales by sector (residential, commercial, industrial, and transportation) in dollars and MWhs and average prices paid by each sector.[29] We inflated the sales data (dollars and MWhs) though 2020 using the historical growth rates for each sector for each year. We then calculated a price for each sector by dividing the dollar value of the retails sales by kWhs. Then we calculated a weighted average kWh price for all sectors using MWhs of electricity sales for each sector as weights. To calculate the percentage electricity price increase we divided our estimated price increase by the weighted average price for each year. For example, in 2017 for our average cost case we divided our average price of 15.36 cents per kWh by our estimated price increase of 1.24 cents per kWh for a price increase of 8.2 percent.

Table 11: Elasticities for the Economic Variables

Economic Variable	Elasticity
Employment	-0.022
Gross wage rates	-0.063
Investment	-0.018
Disposable Income	-0.022

Using these three different utility price increases – 1 percent, 4.5 percent and 5.25 percent – we simulated each of the six STAMP models to determine what outcome these utility price increases would have on each of the six states' economy. We then averaged the percent changes together to determine what the average effect of the three utility increases. Table 11 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state of Maine discussed above.

We applied the elasticities to percentage increase in electricity price and then applied the result to Maine economic variables to determine the effect of the RPS. These variables were gathered from the Bureau of Economic Analysis Regional and National Economic Accounts as well as the Bureau of Labor Statistics Current Employment Statistics.[30]

Life Cycle Analysis

For our LCA we used various studies to determine what the cradle to grave emissions per MWh was, taking into account construction, decommission, operation and maintenance.

For coal we reviewed three different system types: An 'average system' that accounts for emissions from typical coal fired generation in 1995; New Source Performance Standards based on requirements put into effect for all plants built after 1978; and Low Emission Boiler Systems, which are newer, more efficient coal plants.[31] The LCA calculations account for various inputs including, but not limited to, mining, transportation of minerals, power plant operation as well as decommissions and disposal of a plant. Natural gas plants' LCAs were based on the LCA for Gas Combined Cycle Power Generation plants, a type of plant that is similar to the majority of the natural gas plants in the United States.[32]

The LCA for wind power accounted for both onshore and offshore wind power, which has different values for manufacturing, dismantling, operation and transportation for each type.[33] Solar photovoltaic estimates were wide ranging, but a Science Direct paper supplied an in-depth, comprehensive review.[34] It reviewed three different types of crystalline silicone modules as well as a CdTe thin film version and induced many different costs such as emissions from building the module and frame (for the crystalline silicone version) as well as operation and maintenance emissions. For biomass and wood waste LCA we used a report that looked at the production of energy using wood and biomass byproducts to produce energy.[35] Different types of delivery systems (lorry, train and barge) for the fuel were identified, as well as construction, operation and decommissioning.

With total emissions per MWh calculated, we were able to use our in-house model to calculate the total emissions that would be added to and removed from the Maine energy system. The first calculation used the amount of renewable energy added per the Class I RPS law, as well as the amount of conventional power that would be removed, after accounting for capacity factor requirements to keep a constant amount of energy produced. Each MWh added was multiplied by its respective LCA emission, and then we subtracted the amount of conventional time LCA emissions. With a basic conversion from grams to metric tons, we had calculated the results seen in Table 5. An identical calculation was done, but not accounting for capacity factors.

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