Renewable Energy in Rhode Island

Big Cost, Little Difference

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TABLE OF CONTENTS

Preface...1

Executive Summary.........................2

Introduction.....................................8

Rhode Island 9

Methodology.................................13

Relevant Legislation 26

Appendices....................................27

PREFACE

The RI Center for Freedom & Prosperity has occasionally weighed in over the years on the energy and related regulatory issues facing Rhode Island, finding that "green" policies cost Rhode Islanders both their wealth and their jobs.[1] Already suffering from one of the worst business climates and Jobs & Opportunity Index (JOI) ratings in the nation,[2] Ocean State families and businesses cannot afford further increases in energy costs or losses in job opportunities.

Yet, as the list of legislation at the end of this document shows, Rhode Island lawmakers are poised to make a deteriorated situation even worse.

Existing renewable portfolio energy standards (RPS), combined with an aggressive 2016 energy policy, will take even more taxpayer and ratepayer dollars out of the general economy in order to fund a special interest climate agenda and result in higher energy costs and a negative drag on the state's economy. As this document shows, the harm done by these costs will all be in the name of a very low-impact, inefficient policy.

Based on this study's findings, the Center strongly recommends that lawmakers reject all proposed new energy mandates in 2016 and, instead, repeal those that are currently written into law.

Findings

Because of its high dependence on electricity generation via natural gas production (98% of in-state generation), Rhode Island can boast a relatively low carbon footprint. However, to increase its renewable energy portfolio from its current level to its RPS-mandated target of 14.5% by 2019, for only a slight improvement, a massive influx of taxpayer and ratepayer dollars will be required, leading to higher electricity prices and a net loss of jobs.

Rhode Island, despite its ocean proximity, is rated as having a low capacity utilization factor for wind and solar. This means it could be very difficult — and costly — to reach its 14.5% target over the next three years.

Exacerbating this condition, "renewable" energy is considerably more expensive to produce than "fossil fuel" energy, meaning that an increase in the renewable portion of the state's energy portfolio necessarily means an increase in electricity costs. Rhode Islanders are well aware of this phenomenon with the controversial Deepwater Wind project, which alone is expected to cost ratepayers upwards of $440 million dollars over its first 20 years.[3]

Overall, the high cost of complying with existing state RPS mandates, combined with the low benefit of a minor reduction of our carbon footprint, should lead reasonable lawmakers to conclude that this so-called "investment" does not present a good value for Rhode Island.

Because of this poor cost-benefit "value proposition," up to five times less than the Environmental Protection Agency (EPA)–suggested standard, Rhode Island should reconsider its existing energy policy approach. Given its highly unfavorable return on investment, the money targeted to meet its RPS goals could be better spent on sorely needed broad-based tax cuts that would benefit every Rhode Islander and actually spur economic growth.

By the numbers, national research by Dr. Timothy Considine comparing projects to a base case without energy mandates finds that if existing RPS capacity targets are to be met, Rhode Island will experience:

- **4,401–6,068 lower employment levels,** despite the few hundred energy jobs created
- **$141–190 million per year in total costs** required to raise renewable production to targets through 2040
- **49–73% as the range for the sustained increase in the cost of electricity** from new solar and wind capacities
- **13–18% as the sustained increase in actual electricity rates** expected to be passed on to consumers
- **$670–893 million per year extracted from the economy** in the form higher electricity rate payments by private sector businesses and families, with the "services" and "construction" industry sectors shouldering the largest burdens
- **$134–205 per ton as the projected cost of carbon dioxide emission reductions** for Rhode Island, well beyond the $40–60 cost standard that the EPA itself recommends

The high costs of achieving small carbon dioxide emission reductions using RPS in Rhode Island prove that it is an inefficient means to address global climate change and represents a poor investment for state taxpayers and ratepayers. As in many other states, the costs of carbon reduction in the Ocean State are significantly higher than EPA standards, while the small stimulus from RPS investment is not large enough to offset the negative effects of higher electricity prices.

EXECUTIVE SUMMARY

Renewable portfolio standards (RPS), now existing in 29 states and the District of Columbia, require utilities to provide a certain percentage of electricity consumption from wind, solar, and other forms of renewable energy. Federal policies, such as the wind production tax credit and the solar investment tax credit, also promote the production of wind and solar power. Given the widespread use of rate-of-return regulation based upon average cost pricing, the costs of these policies are less than transparent. Moreover, to the extent that these policies drive up electricity prices, output and employment could be adversely affected. The objective of this study is to understand and estimate these costs and economic effects.

Central to this effort is the estimation of the opportunity costs of higher-cost, intermittent renewable power in terms of the foregone electricity from lower cost, deployable fossil fuel–fired electricity. These opportunity costs vary considerably by state based upon the cost of existing capacity and availability of wind and solar resources. Accordingly, this study estimates these costs for the twelve states identified in Figure 1. The timing and stringency of the RPS goals varies considerably by state. Moreover, there is wide variation in the size and composition of electricity generation for this sample of states.[4]

To estimate the costs and benefits of RPS, this study develops models of electricity supply and demand for each state. These models are projected using forecasts for coal and natural gas prices out to 2040 from the U.S. Energy Information Administration. The baseline forecast assumes existing electricity production capacity remains in place with new generation requirements met by natural gas integrated combined cycle (NGCC) plants. The RPS scenario imposes the goals identified in Figure 1. Average electricity generation costs, power consumption, and retail rates under the baseline and RPS scenarios are then compared.

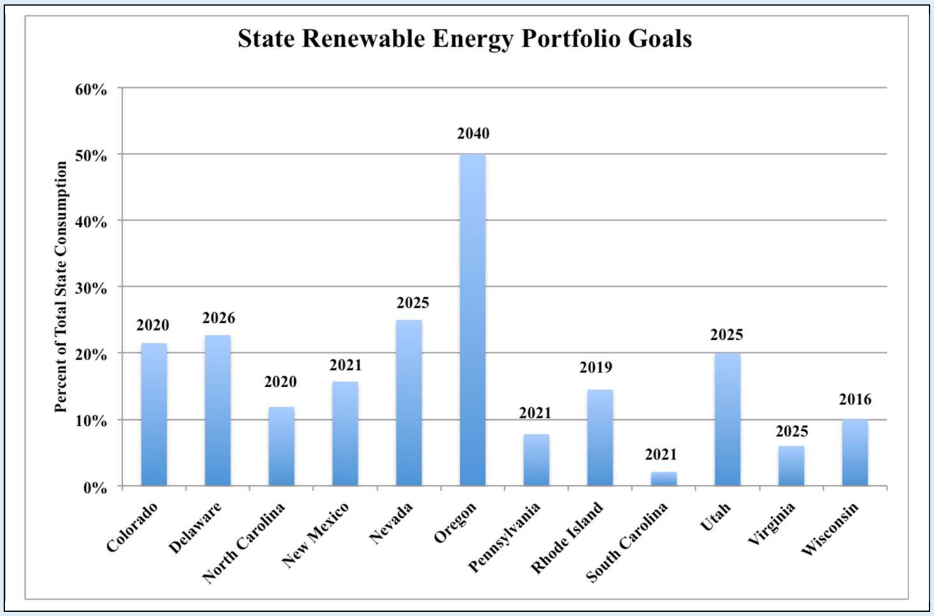
The costs of RPS policies depend upon the opportunity costs of electricity generation from wind and solar. For states with fleets of low-cost electricity generation capacity, imposition of RPS could raise electricity costs significantly because higher-cost wind and solar generation displace low-cost sources of power. While this displacement reduces expenditures on fossil fuels, coal and natural gas plants are cycled to accommodate the intermittent generation of renewable generators, which reduces their thermal efficiency and raises generation costs. On the other hand, building more renewable energy plants to meet RPS goals reduces the need to build new NGCC plants. Finally, investments in RPS capacity earn federal tax subsidies. Wind power receives a production tax credit of $23 per megawatt hour (Mwh) while solar plants receive a 30% investment tax credit. Hence, RPS policies contribute to lower federal tax revenue.

These costs are summarized in Table 1 for all 12 states included in the study. For example, in 2016, the RPS goals involve $5.4 billion in additional expenditures to build and operate the required RPS facilities, $271 million in cycling costs, and $1.8 billion of tax subsidies. These costs are partially offset by $1.5 billion in fossil fuel cost savings and $261 in avoided new NGCC generation costs. Hence, the total net cost of RPS policies is $5.8 billion in 2016. The total net costs of RPS policies reach $8.7 billion in 2025 and then decline to $8.1 billion in 2040 after RPS goals are met and the unit costs of solar and wind decline because of technological improvements.

These higher costs are passed on to customers in the form of higher retail electricity prices, summarized in Table 2. States with modest RPS goals, such as

Figure 1: RPS Goals by State

Of the states included in this study, Rhode Island's RPS percentage is in the middle of the pack, but its target date is among the earliest.



South Carolina, experience moderate rate increases. Similarly, states meeting their RPS goals with wind, such as Colorado, face rate increases of roughly 5%. On the other hand, states meeting rather ambitious RPS goals with relatively higher-cost solar power, such as North Carolina, Nevada, Utah, and Virginia, incur much steeper electricity rate increases.

Electricity rate increases peak as RPS goals are reached in the early 2020s for most states. Thereafter, electricity rate increases begin to taper off as the costs of wind and solar decline due to technological improvements. Despite these expected reductions in the cost of wind and solar technology, RPS polices increase prices for electricity.

Many economic studies in the peer-reviewed literature demonstrate that higher energy prices reduce economic growth and employment. Energy is an essential factor of production and consumption activities. Given limited substitution possibilities, higher electricity prices raise business costs and consumer energy bills, which reduces spending on other goods and services. Investments in renewable energy, however, constitute an economic stimulus.

A comparison of these economic impacts is summarized in Table 3 for the 12-state sample. For example, in 2025 higher electricity prices associated with RPS policies reduce value added by $23.1 billion. Investments required for new renewable

Table 1: Costs of RPS for 12 State Sample ($M, 2013 Dollars)

	2016	2020	2025	2030	2035	2040
Renewable energy costs	5,400.0	7,815.2	8,881.6	9,283.8	9,693.2	10,119.0
Cycling costs	271.1	316.0	339.6	371.9	409.2	452.6
Tax subsidies	1,830.1	2,672.2	3,098.0	3,287.2	3,485.7	3,698.8
New fuel costs	-1,478.3	-2,319.5	-2,966.3	-3,493.3	-4,071.0	-4,687.0
New fossil fuel costs	-260.7	-462.0	-597.5	-619.6	-642.1	-652.3
Total net costs	5,762.2	8,022.0	8,755.4	8,829.9	8,875.0	8,931.1

Table 2: Impact of RPS Policies on Retail Electricity Prices (% Change)

	2016	2020	2025	2030	2035	2040
Colorado	6.12	8.23	7.69	7.32	6.69	5.93
Delaware	11.02	14.50	14.99	12.50	10.14	8.20
North Carolina	10.04	16.06	14.12	12.55	11.03	9.79
New Mexico	6.18	6.77	5.95	5.30	4.54	3.92
Nevada	14.77	15.60	15.14	13.28	11.21	9.12
Oregon	9.41	10.00	11.09	14.13	16.42	18.13
Pennsylvania	2.14	2.56	2.54	2.40	2.25	2.08
Rhode Island	13.61	18.16	16.62	15.55	14.46	13.17
South Carolina	0.39	1.52	2.08	1.97	1.85	1.75
Utah	5.13	9.07	12.78	11.78	10.67	9.47
Virginia	5.45	7.75	9.85	8.76	7.74	6.93
Wisconsin	4.34	4.29	4.01	3.70	3.39	3.08

energy plants increase value added by $668 million. With a small offset from reductions in required NGCC plants to meet load growth, the net reduction in value added is nearly $22.5 billion. Similarly, gross employment losses are over 160 thousand in 2025 but over 9,000 jobs are created building and operating new solar and wind capacity to meet RPS goals. But again the net change involves over 150 thousand jobs lost in 2025. Overall, this study finds that the stimulus from building and operating renewable energy facilities is offset by the negative effects that higher electricity rates have on employment and value added.

The estimated losses in value added for each of the twelve states are summarized in Table 4. The largest losses occur in North Carolina with value-added reductions between $3.9 billion in 2016 to nearly $7.1 billion in 2020. Losses in annual value added exceed $1 billion in eight other states.

The employment effects of RPS policies are summarized in Table 5. The jobs lost by state mirror

Table 3: RPS Effects on Value Added and Employment for Studied States

	2016	2020	2025	2030	2035	2040
Net value added ($M, 2013 dollars)	-14,856	-21,543	-22,495	-21,124	-19,346	-17,642
Electric prices	-16,779	-22,799	-23,140	-21,555	-19,786	-18,100
RPS investment	2,069	1,290	668	432	439	456
NGCC investment	-146	-34	-22	-2	1	2
Employment effect (# of jobs)	-90,026	-141,066	-152,727	-145,830	-134,318	-123,116
Electric prices	-118,606	-159,094	-161,595	-151,605	-140,199	-129,223
RPS investment	29,826	18,332	9,073	5,796	5,870	6,092
NGCC investment	-1,246	-305	-206	-21	10	15

Table 4: RPS Effect on Value Added by State ($M, 2013 Dollars)

	2016	2020	2025	2030	2035	2040
Colorado	-1,442	-1,996	-1,992	-1,895	-1,730	-1,530
Delaware	-603	-812	-839	-715	-578	-466
North Carolina	-3,899	-7,145	-6,664	-5,918	-5,196	-4,606
New Mexico	-239	-444	-390	-348	-298	-251
Nevada	-1,711	-1,792	-1,715	-1,534	-1,287	-1,038
Oregon	-1,451	-1,571	-1,636	-2,022	-2,374	-2,636
Pennsylvania	-1,226	-1,503	-1,640	-1,545	-1,449	-1,337
Rhode Island	-629	-890	-813	-760	-707	-643
South Carolina	-63	-198	-349	-318	-298	-283
Utah	-662	-1,420	-2,025	-1,964	-1,777	-1,575
Virginia	-1,865	-2,655	-3,390	-3,149	-2,778	-2,486
Wisconsin	-1,065	-1,116	-1,041	-958	-874	-791
Total	-14,856	-21,543	-22,495	-21,124	-19,346	-17,642

the losses in value added. Again, the magnitudes differ by state, depending upon the stringency of the RPS goals, the size of the state, and the technologies available for each state to meet its RPS goals. Solar energy is the only feasible means to attain RPS goals for eastern states because of limited wind resources.

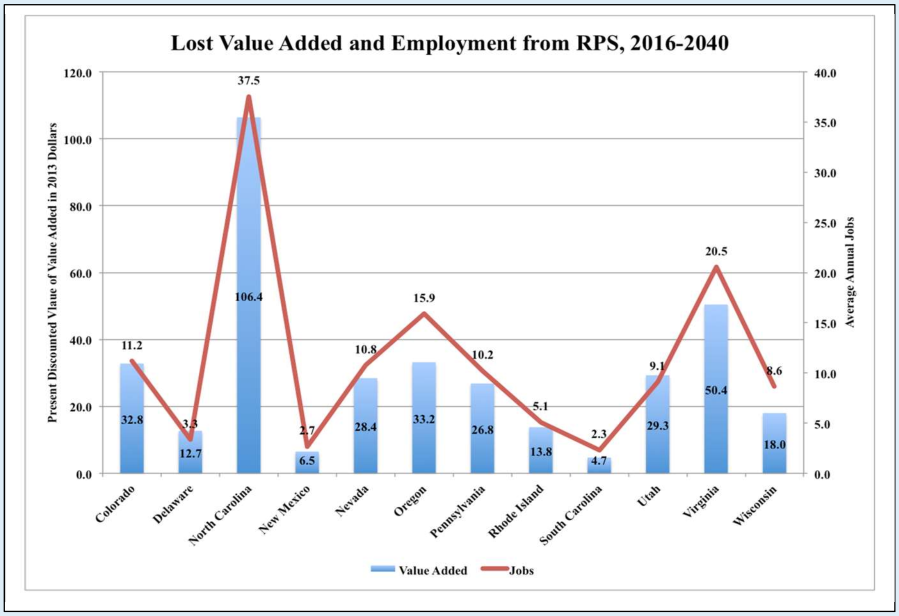
Figure 2 summarizes the economic effects using the present discounted value of lost value added and average annual job losses from 2016 to 2040. The largest losses occur in North Carolina, with a cumulative loss in value added of over $106 billion and annual average job losses of more than 37,000. The next-largest losses occur in Virginia, with over $50 billion in lost value added and more than

Table 5: RPS Effect on Employment by State

	2016	2020	2025	2030	2035	2040
Colorado	-8,060	-11,619	-12,445	-11,823	-10,779	-9,516
Delaware	-2,705	-3,845	-3,970	-3,536	-2,846	-2,272
North Carolina	-17,821	-43,277	-44,093	-39,107	-34,289	-30,345
New Mexico	-743	-3,483	-3,060	-2,724	-2,333	-1,921
Nevada	-11,827	-12,540	-11,868	-10,813	-9,037	-7,237
Oregon	-12,309	-13,459	-13,547	-16,428	-19,422	-21,637
Pennsylvania	-7,781	-9,712	-11,396	-10,726	-10,046	-9,255
Rhode Island	-4,003	-6,023	-5,496	-5,137	-4,771	-4,339
South Carolina	-561	-1,331	-3,084	-2,794	-2,617	-2,480
Utah	-1,912	-7,137	-10,517	-11,153	-10,077	-8,916
Virginia	-13,182	-18,779	-24,060	-23,144	-20,399	-18,241
Wisconsin	-9,121	-9,862	-9,193	-8,447	-7,701	-6,957
Total	-90,026	-141,066	-152,727	-145,830	-134,318	-123,116

Figure 2: Cumulative Economic Effects of RPS

Rhode Island's cumulative value-added loss will nearly reach $15 billion dollars, with over 5,000 jobs lost annually.



20,000 lost jobs per year. Five other states — Colorado, Nevada, Oregon, Pennsylvania, and Utah — incur losses exceeding $25 billion in value added and 9,000 jobs per year from 2016 to 2040 based on the economic burdens associated with RPS policies.

RPS policies do generate benefits by reducing carbon dioxide emissions. These savings, however, come at a relatively high price, with the avoided cost of carbon of between $38 and $235 per ton in 2016 and between $31 and $136 per ton in 2040 (see Table 6). An emissions weighted average of CO2 abatement costs across states is $78 in 2016 and $62 dollars per ton in 2040.

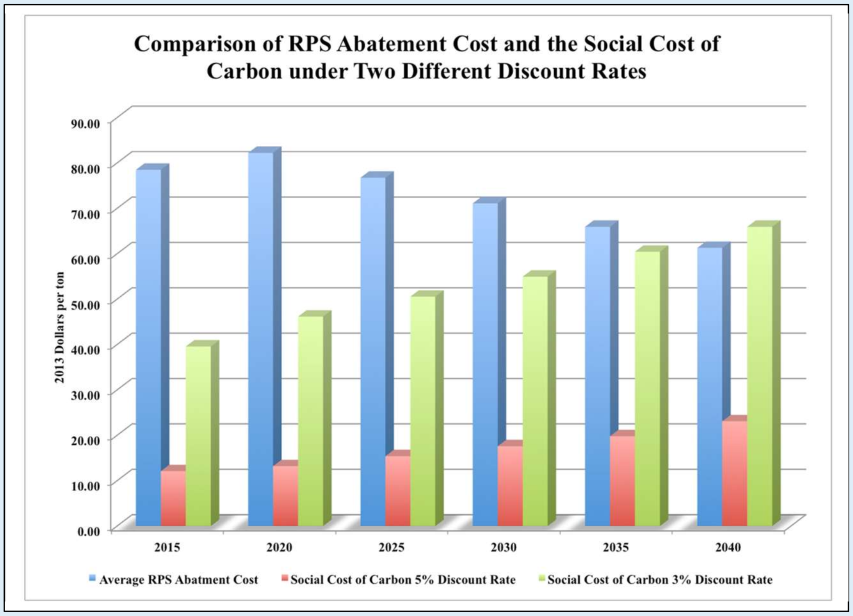
Figure 3 shows that the social cost of carbon estimated by the U.S. Environmental Protection Agency is well below these average avoided

Table 6: Costs of CO2 Reductions Using RPS

	2016	2020	2025	2030	2035	2040
Colorado	37.92	41.89	40.22	39.79	38.56	36.78
Delaware	105.74	88.83	77.70	68.22	60.16	53.31
North Carolina	199.03	183.27	162.12	147.65	134.22	122.56
New Mexico	45.92	39.80	37.09	35.02	32.46	30.59
Nevada	76.82	56.83	51.17	46.68	42.64	38.66
Oregon	45.89	49.06	45.93	47.68	47.40	46.51
Pennsylvania	44.05	44.21	42.37	41.43	40.50	39.41
Rhode Island	205.42	172.39	156.73	148.99	141.55	133.72
South Carolina	103.38	156.21	133.88	127.07	120.60	115.27
Utah	97.22	85.42	82.54	76.74	71.33	65.94
Virginia	234.91	203.97	181.92	161.71	147.34	136.03
Wisconsin	54.22	51.15	49.46	47.67	45.88	44.06

Figure 3: RPS Abatement Costs and the Social Cost of Carbon

The cost of carbon abatement is well above the estimated social cost of failing to do so as determined by the U.S. Environmental Protection Agency.



emissions costs, suggesting that RPSs are a relatively expensive strategy to cut greenhouse gas emissions. In summary, this study finds that the economic impacts of Renewable Portfolio Standards vary significantly across states depending upon the goals and the availability of solar and wind resources. Across all states, however, RPS policies increase electricity prices.

Although RPS investments stimulate some economic activity, the negative effects associated with higher electricity prices offset the economic stimulus from these RPS investments. In many cases, especially for states that must utilize solar energy technology to meet RPS goals, the cost per ton of carbon is much higher than the social cost of carbon estimated by the U.S. federal government. Avoided carbon costs are lower for wind power but still involve net losses in value added and employment. These findings suggest that Renewable Portfolio Standards for the twelve states examined in this study are a costly and inefficient means to reduce greenhouse gas emissions, and they reduce economic growth and employment.

INTRODUCTION

Thirty states and the District of Columbia have adopted renewable portfolio standards (RPSs) specifying shares of electricity consumption provided by renewable energy. RPS proponents argue that these policies are needed to reduce greenhouse gas emissions. They also argue that the construction of renewable energy facilities increases employment opportunities. Opponents assert that RPSs increase electricity generation costs and rates paid by customers, which reduces regional economic activity. The objective of this study is to provide a balanced look at this issue, weighing the costs and benefits of RPS.

Our focus is on 12 states in four regions of the United States: the Northeast and Mid-Atlantic states of Rhode Island, Pennsylvania, and Delaware; the South Atlantic states of Virginia and North and South Carolina; the Midwestern state of Wisconsin; and five western states, including Colorado, New Mexico, Utah, Nevada, and Oregon. These states are quite diverse both in respect to their sources of electric power generation and to their economies. Moreover, their RPS policies also differ in terms of timelines, goals, and an array of special provisions. This sample of states, therefore, provides a rather robust sample from which to determine the net social costs and benefits of RPS.

There are several components of these benefits and costs. On the benefit side, there are avoided greenhouse gas emissions and additional economic activity generated by the construction of renewable energy plants. The costs include three components:

- First, the foregone state and federal tax revenue from renewable energy tax credits
- Second, the lost consumer surplus from higher electricity rates induced by the RPS
- Finally, higher electricity rates' effect on regional economic activity, reducing output, income, employment, and state and local tax revenue

The methods used to estimate these costs and benefits are described in the first appendix. The following section discusses the findings specifically for Rhode Island, presenting the effects on electricity markets and the environmental and economic impacts.

RHODE ISLAND

Rhode Island generates 6.2 million MWh (see Table 7). Natural gas provides more than 98% of this electricity generation. Wind and solar capacity in Rhode Island is currently is very limited. The following two subsections summarize the effects of existing and future RPS goals on the electricity market and state's value added and employment.

Table 7: Capacity, Generation, and Utilization Rates for Rhode Island, 2013

Energy Source	Capacity MW	Generation MWh	Utiliza-tion %
Coal	0	0	0.0000
Geothermal	0	0	0.0000
Hydroelectric	3	4,447	0.1813
Natural gas	1,971	6,139,090	0.3555
Nuclear	0	0	0.0000
Other	0	0	0.0000
Other biomass	40	48,132	0.1360
Other gas	0	0	0.0000
Petroleum	18	50,540	0.3260
Pumped storage	0	0	0.0000
Solar	7	2,007	0.0332
Wind	3	2,590	0.0986
Wood	0	0	0.0000
Total	2,042	6,246,807	0.3492

Effects on Electricity Sector

The RPS goal for RI is 14.5% of total consumption by 2019. The effects on electricity markets from the enactment of these goals are presented in Table 8. The RPS goals reduce the need for additional new NGCC. For instance, in the base case without additional RPS capacity, new NGCC capacity required to balance the market is 36.1 MW in the base case, while under the RPS incremental NGCC capacity declines to 17.6 MW in 2025.

Table 8: Effects of RPS on Rhode Island Electricity Market

	2016	2020	2025	2030	2035	2040
New capacity (megawatts)						
NGCC without RPS	36.1	16.3	14.8	16.0	16.7	17.1
NGCC with RPS	17.6	12.8	14.8	16.1	16.9	17.4
RPS Wind	63.0	5.9	6.8	7.4	7.8	8.0
RPS Solar	55.7	5.2	6.0	6.6	6.9	7.1
Generation (million megawatt hours)						
New NGCC without RPS	0.7	1.3	1.9	2.5	3.1	3.7
New NGCC with RPS	0.5	0.9	1.5	2.0	2.7	3.3
Legacy RPS	0.0	0.0	0.0	0.0	0.0	0.0
New RPS	0.9	1.3	1.4	1.5	1.6	1.7
Change from base case (%)						
Average costs	57.54	73.17	64.68	60.52	55.60	48.71
Electricity consumption	-1.90	-3.72	-3.78	-3.57	-3.35	-3.08
Average rates	13.55	18.11	16.57	15.51	14.42	13.13
Average rates + legacy costs	13.61	18.16	16.62	15.55	14.46	13.17

Slightly over 56% of new RPS capacity for Rhode Island is supplied by solar power, with the remainder met by new wind generating plants. RPS wind and solar capacity to meet the RPS goals are 63.0 and 55.7 MW, respectively, in 2016 and 5.9 and 5.2 MW, respectively, in 2020. The electricity generation from these new facilities rises from 0.9 million MWh in 2016 to 1.7 million MWh in 2040.

The increases in average electricity costs from new RPS capacity additions are 58% in 2016, 73% in 2020, and between 49 and 65 percent after 2025 (see Table 8). These steep increases in costs are due to the low capacity factors for wind and solar in Rhode Island. With legacy costs, average electricity rates in Rhode Island increase 13.6% in 2016 due to RPS. After 2016, rates increase 13–18% thereafter compared to the base case without RPS standards. These substantial rate increases reflect the low capacity utilization rates for wind and solar in Rhode Island and the rather ambitious 14.5% RPS goal.

The decomposition of RPS costs for the Rhode Island electricity sector appear in Table 9. RPS legacy costs are negligible, given the very small amount of existing wind and solar capacity. The costs for additional renewable capacity to meet Rhode Island's RPS goals are also summarized.

The direct costs to achieve 7.8% of consumption supplied by renewable energy are $108.9 million in 2016 and rise to over $142 million in 2020, $135 million in 2025, and around $130 million after 2030. After adding cycling costs and deducting for fossil fuel and NGCC capacity costs, the net costs to meet the RPS goal are $109 million in 2016 and over $125 million per year thereafter. With subsidies, the total costs of Rhode Island's RPS are $141 million in 2016, $190 million in 2020, $183 million in 2025, and more than $179 million per year from 2030 to 2040.

The RPS policies in Rhode Island reduce carbon dioxide emissions by 0.69 million tons in 2016 and over 1.3 million tons per year by 2040. The direct

Table 9: Costs of Rhode Island RPS

	2016	2020	2025	2030	2035	2040
Total cost ($M, 2013 dollars)	140.9	190.1	183.3	182.7	181.8	179.1
Net legacy costs	0.6	0.5	0.5	0.5	0.5	0.4
Direct legacy costs	0.6	0.6	0.6	0.6	0.5	0.5
Cycling legacy costs	0.0	0.0	0.0	0.0	0.0	0.0
Legacy fuel costs	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Net new costs	108.9	142.4	135.2	134.0	132.3	128.9
Direct new costs	118.2	174.1	176.6	179.8	183.0	186.1
Cycling new costs	0.3	0.4	0.4	0.4	0.5	0.5
New fuel costs	-3.9	-21.3	-29.8	-34.3	-39.1	-45.4
New NGCC costs	-5.6	-10.8	-12.0	-12.0	-12.0	-12.3
RPS tax subsidies	31.4	47.1	47.6	48.3	49.0	49.7
CO2 reduction (million tons)	0.69	1.10	1.17	1.23	1.28	1.34
Cost per ton (2013 dollars)	205.42	172.39	156.73	148.99	141.55	133.72
Direct costs	159.59	129.65	116.05	109.64	103.40	96.62
Subsidy costs	45.84	42.74	40.68	39.36	38.15	37.11

costs per ton of avoided emissions are $159.59 per ton in 2016, declining to $96.62 per ton in 2040 as wind and solar costs decline over time. Tax subsidies, however, are over $45.84 per ton in 2016 and remain over $37 per ton in 2040. The total cost of avoided carbon emissions, therefore, is $205.42 per ton in 2016, which gradually declines to $133.72 per ton in 2040. These large unit costs of carbon emission reductions reflect the low capacity utilization rates for wind and solar in Rhode Island. Another factor is the predominance of natural gas in total generation so that any generation displaced by renewables has relatively low emissions.

These RPS carbon abatement costs are far above the EPA social cost of carbon, which is estimated at $12 to $24 per ton, assuming a 5% discount rate, suggesting that RPS policies in Rhode Island are an inefficient greenhouse gas emission strategy. Even under a 3% discount rate, EPA's social cost of carbon is around $40 per ton in 2016 and gradually increases to $60 per ton in 2040. So from a global cost-benefit perspective, adopting RPS policies in Rhode Island is not cost effective. There are also economic effects from higher electricity rates that lead to losses in economic output and employment. These impacts are presented and discussed in the next section.

Economic Effects

By raising retail prices for electricity, RPS goals increase consumer electricity bills and the cost of providing goods and services in the Rhode Island economy. These effects of higher electricity prices are summarized by sector from 2016 to 2040 in Table 10. Annual losses in Rhode Island value added range from $648 million in 2040 to $893 million in 2025. Employment levels are 4,000–5,000 jobs below employment in the base case without RPS (see Table 11).

These losses from higher electricity prices are partially offset by output and employment gains from building and operating electricity capacity needed to meet RPS goals. These different effects of RPS on Rhode Island value added and employment are summarized in Table 12. For example, in 2020 RPS investments contributed $4.1 million in value added and 53 jobs.

Table 10: Effects of RPS on Rhode Island Value Added by Sector ($M, 2013 Dollars)

	2016	2020	2025	2030	2035	2040
Metals	-51.72	-69.00	-63.16	-59.11	-54.95	-50.04
Paper	-10.89	-14.53	-13.30	-12.44	-11.57	-10.53
Wood	-2.72	-3.63	-3.32	-3.11	-2.89	-2.63
Other Man	-32.66	-43.58	-39.89	-37.33	-34.70	-31.60
Textiles	-6.80	-9.08	-8.31	-7.78	-7.23	-6.58
Minerals	-2.72	-3.63	-3.32	-3.11	-2.89	-2.63
Const.	-100.71	-134.37	-122.99	-115.10	-107.00	-97.44
Trans.	-21.78	-29.05	-26.59	-24.89	-23.13	-21.07
Services	-496.75	-662.77	-606.64	-567.75	-527.76	-480.61
Utilities	57.16	76.26	69.81	65.33	60.73	55.30
Total	-669.59	-893.37	-817.72	-765.29	-711.40	-647.83

As in other states, however, the stimulus from RPS investment is not large enough to offset the negative effects of higher electricity prices. On balance, therefore, net annual losses in value added from Rhode Island's RPS goals are $629 million in 2016, $890 million in 2020, $813 million in 2025, and remain over $640 million through the end of the forecast horizon. Employment levels are over 4,000–6,000 jobs lower during the forecast period compared to the base case.

In summary, the cost of avoiding carbon dioxide emissions using RPS in Rhode Island is much higher than EPA estimates of the social cost of carbon, assuming a 5% discount rate, or even assuming a 3% discount rate after 2025. From a global perspective, therefore, RPS in Rhode Island is an inefficient means to address global climate change.

Households and businesses in Rhode Island pay a price for RPS. Such policies raise electricity costs

Table 11: Effects of RPS on Rhode Island Employment by Sector (# of Jobs)

	2016	2020	2025	2030	2035	2040
Metals	-71	-94	-86	-81	-75	-68
Paper	-86	-114	-105	-98	-91	-83
Wood	-42	-56	-52	-48	-45	-41
Other Man	-554	-739	-676	-633	-588	-536
Textiles	-52	-69	-63	-59	-55	-50
Minerals	-8	-11	-10	-9	-9	-8
Const.	-520	-694	-635	-594	-552	-503
Trans.	-365	-487	-445	-417	-388	-353
Services	-2,978	-3,973	-3,637	-3,403	-3,164	-2,881
Utilities	128	171	156	146	136	124
Total	-4,548	-6,068	-5,554	-5,198	-4,832	-4,401

Table 12: Net Effects of RPS on Rhode Island Value Added and Employment

	2016	2020	2025	2030	2035	2040
RPS investment ($M, 2013 dollars)	230.48	20.97	23.23	24.36	24.54	24.40
Net value-added change ($M, 2013 dollars)	-629.46	-890.22	-813.16	-760.50	-706.55	-642.97
Electric prices	-669.59	-893.37	-817.72	-765.29	-711.40	-647.83
RPS investment	45.39	4.12	4.56	4.78	4.81	4.77
NGCC investment	-5.26	-0.97	-0.01	0.02	0.04	0.09
Net employment change (# of jobs)	-4,003	-6,023	-5,496	-5,137	-4,771	-4,339
Electric prices	-4,548	-6,068	-5,554	-5,198	-4,832	-4,401
RPS investment	587	53	59	61	61	61
NGCC investment	-42	-8	0	0	0	1

that, on balance, result in a net reduction in the state's value added and employment, even after accounting for the economic stimulus from building and operating renewable energy facilities. These economic effects are significant because wind and solar capacity factors in Rhode Island are low and nearly all existing generation is from natural gas. As renewable goals are met, wind and solar generation displaces relatively low-emission natural gas. Hence, the emissions savings are relatively small, and the unit abatements costs are large.

APPENDIX A: METHODOLOGY

Renewable portfolio standards (RPSs) are generally met with wind and solar electric generating technologies. Relatively small amounts of biomass and other renewable sources of generation are also used to meet these standards. Given this fact and the limited information available on alternatives to wind and solar, this study assumes that RPS goals are met by building wind and solar generation capacity.

Adding these facilities to a generation fleet incurs opportunity costs, which vary depending upon the cost, efficiency, and composition of existing generation capacity. The benefits in terms of avoided emissions will also vary with the characteristics of the generation fleet. Hence, the opportunity costs of RPS policies could vary considerably by state. If a state has a high cost of generation, adding wind and solar would involve relatively lower costs than those incurred for a system with very low costs. These costs are also affected by coal, oil, and natural gas prices among, other factors. If these prices rise, the increase in average generation costs from adopting RPS policies would be relatively lower.

Another important adjustment affecting the opportunity costs of RPS policies is how the demand for electricity adjusts to the higher electricity rates that would be required to recover the additional costs of building and operating renewable energy plants. This price-induced energy conservation would reduce the costs of RPS policies.

To estimate these electricity supply and demand adjustments in response to RPS policies, this study develops a simplified version of the models developed by Considine and Manderson (2014 and 2015), in which electricity demand models are integrated with engineering-economic models of electric power generation. Electricity demand is projected based upon assumptions for the growth of gross state product and upon retail electricity prices that are determined based upon average generation costs determined from the engineering-economic model of electricity generation.

These costs are calculated based upon observed levels of installed generation capacity, utilization rates, and unit costs of generation that include operating and capital cost recovery. In other words, available generation from existing natural gas, coal, nuclear, hydro, and renewable capacity are estimated by multiplying the respective capacities by their utilization rates. The displacement of fossil fuel generation and associated efficiency losses due to suboptimal cycling of these plants to balance system load with rising levels of intermittent renewable energy generation are estimated using the Avoided Emissions and Generation Tool developed by the U.S. Environmental Protection Agency (EPA; 2015). For this document, these models are estimated for each of the 12 states included in the study.

These electricity supply and demand models for each state are simulated from 2016 to 2040 under two scenarios. The first scenario is the base case defined as the existing generation fleet without RPS policies in place. For existing wind and solar capacity, which are assumed to reflect current RPS, costs and benefits are computed separately and are designated as RPS legacy costs. Electricity supply and demand are balanced by new investment and generation from natural gas integrated combined cycle (NGCC) plants. The second scenario assumes the RPS goals are phased in over the forecast horizon, specifying an amount of wind and solar generation equal to the RPS share multiplied by projected electricity consumption. In this case, the required amount of new NGCC capacity would be reduced due to the rising share of renewable energy in the generation portfolio. The effects of RPS policies on retail electricity prices are determined by comparing retail electricity prices in these two scenarios.

These retail electricity price changes, and the net changes in new power plant investments will affect local economic activity. Value added and employment multipliers reported by recent economic studies will be used to estimate the state-level economic effects of RPS policies. The Jobs and Economic Development Impact (JEDI) modeling tool developed by the National Renewable Energy Laboratory (2015) is used to estimate the effects of power plant investments on value added and employment. The net effects on employment and value added are then estimated.

Benefits are the avoided air emissions, which are estimated by taking the difference between emissions in the base case and the RPS scenario including the emissions saved from existing wind and solar capacity. The total cost of RPS policies defined above divided by these emission savings provide an estimate of the unit cost of greenhouse gas reductions from RPS policies.

The following five subsections describe the results obtained from the econometric estimation of the electricity demand models, the specification of the electricity generation cost models, average cost calculations under RPS policies, the decomposition of RPS opportunity costs, and the parameters used for the economic impact analysis.

Electricity Demand

The demand for electricity is a simple partial adjustment model in log-linear form, in which total electricity consumption in state *i*, Q_{it} , is a function of the real price for electricity, P_{it}, gross state product or total value added, Y_{it}, and lagged consumption, Q_{it-1}:

$$\ln Q_{it} = \alpha_i + \beta_i \ln P_{it} + \gamma_i \ln Y_{it} + \lambda_i \ln Q_{it-1} \qquad (1)$$

where α_i, β_i, γ_i, and λ_i are parameters estimated with ordinary least squares. The results for alternative specifications including a first differenced version, a specification with natural gas prices, and fixed and random effects models appear in Appendix A: References section below and are not substantially different from those reported in Tables 13–15.

The econometric estimates for equation (1) are reported in Table 13. As expected, the coefficients on price for all 12 states are negative, indicating an inverse relationship between electricity consumption and retail prices. Eight out of the 12 price coefficients are statistically different from zero at either the one- or five-percent level of significance. Similarly, the coefficients on gross state product are positive, which reflects the well-known positive relationship between economic growth and electricity use. Eleven of the 12 estimated income coefficients are statistically significant.

Table 13: Net Effects of RPS on Rhode Island Value Added and Employment

	Estimate	Constant	Log of Real Price	Log of Real GSP	Lagged Quantity
Colorado	Estimate	-0.4902	-0.0379	0.1447	0.7701
	t-Statistic	-1.9138	-2.4042	3.2219	12.8862
	P-Value	[.063]	[.021]	[.003]	[.000]
Delaware	Estimate	-0.6542	-0.1395	0.2465	0.5723
	t-Statistic	-2.9194	-4.7098	4.8575	7.0174
	P-Value	[.006]	[.000]	[.000]	[.000]
North Carolina	Estimate	-0.2608	-0.0278	0.1706	0.6959
	t-Statistic	-1.0556	-1.1898	2.3595	6.1758
	P-Value	[.298]	[.241]	[.023]	[.000]
New Mexico	Estimate	0.0475	-0.0280	0.0392	0.9099
	t-Statistic	0.1156	-0.5632	0.7022	13.3443
	P-Value	[.909]	[.577]	[.487]	[.000]
Nevada	Estimate	-1.0216	-0.1686	0.2877	0.6216
	t-Statistic	-4.8414	-6.2297	6.2116	10.2848
	P-Value	[.000]	[.000]	[.000]	[.000]
Oregon	Estimate	0.5212	-0.0491	0.0849	0.7277
	t-Statistic	2.7591	-1.5102	2.2751	7.4734
	P-Value	[.009]	[.139]	[.028]	[.000]
Pennsylvania	Estimate	0.1410	-0.0814	0.2132	0.5643
	t-Statistic	1.1377	-3.9395	3.7515	5.2630
	P-Value	[.262]	[.000]	[.001]	[.000]
Rhode Island	Estimate	-0.4151	-0.1020	0.1981	0.5877
	t-Statistic	-3.1521	-6.3470	6.2642	9.4167
	P-Value	[.003]	[.000]	[.000]	[.000]
South Carolina	Estimate	-1.4600	-0.0864	0.4437	0.3557
	t-Statistic	-3.5542	-3.5018	4.5002	2.6698
	P-Value	[.001]	[.001]	[.000]	[.011]
Utah	Estimate	-0.9474	-0.0228	0.2057	0.6969
	t-Statistic	-1.8262	-1.3388	2.4048	6.2836
	P-Value	[.075]	[.188]	[.021]	[.000]
Virginia	Estimate	-0.4332	-0.0385	0.1711	0.7208
	t-Statistic	-1.4929	-1.9802	2.6287	7.8650
	P-Value	[.144]	[.055]	[.012]	[.000]
Wisconsin	Estimate	-1.1833	-0.0816	0.3342	0.5010
	t-Statistic	-3.0000	-3.1200	3.8977	4.2555
	P-Value	[.005]	[.003]	[.000]	[.000]

The summary statistics reported in Table 14 reflect a very good fit of the models to the observed data and the absence of autocorrelation. Eight of the 12 models have very low probabilities of unit roots in the residuals. The own price and output elasticities appear in Table 15. The short-run and long-run own price elasticities average -0.07 and -0.20, respectively — quite similar to those found in the economic literature. Output elasticities average 0.2 and 0.5 in the short and long run, respectively, and again are very close to estimates found in many other studies. With projections of future gross state product and retail prices, equation (1) can be used to project future electricity consumption.

Table 14: Electricity Demand Model Summary Fit Statistics by State

	Adj. R-Squared	Durbin H Probability Value	Weighted Symmetric Unit Root Prob.
Colorado	0.998	0.029	0.010
Delaware	0.990	0.481	0.000
North Carolina	0.993	0.576	0.274
New Mexico	0.990	0.494	0.000
Nevada	0.998	0.288	0.001
Oregon	0.943	0.780	0.739
Pennsylvania	0.987	0.975	0.031
Rhode Island	0.992	0.259	0.416
South Carolina	0.995	0.931	0.021
Utah	0.997	0.738	0.008
Virginia	0.996	0.224	0.143
Wisconsin	0.994	0.308	0.004

Table 15: Short- and Long-Run Price and Income Elasticities of Electricity Demand

	Own Price Elasticity		Gross State Product Elasticity	
	Short Run	Long Run	Short Run	Long Run
Colorado	-0.038	-0.165	0.145	0.629
Delaware	-0.139	-0.326	0.246	0.576
North Carolina	-0.028	-0.092	0.039	0.129
New Mexico	-0.028	-0.311	0.039	0.435
Nevada	-0.169	-0.445	0.288	0.760
Oregon	-0.049	-0.180	0.085	0.312
Pennsylvania	-0.081	-0.187	0.213	0.489
Rhode Island	-0.102	-0.247	0.198	0.480
South Carolina	-0.086	-0.134	0.444	0.689
Utah	-0.023	-0.075	0.206	0.679
Virginia	-0.023	-0.082	0.206	0.737
Wisconsin	-0.082	-0.163	0.334	0.670
Average	-0.071	-0.201	0.204	0.549

Generation Costs

The supply of electricity is determined by simple engineering-economic relationships and generation cost calculations. Generation is determined by multiplying installed capacity by utilization rates. Costs of electricity generation are determined on the basis of the levelized costs of generation, which include operating costs and capital cost recovery charges. Retail electricity prices equal average generation cost plus a fixed markup for transmission and distribution charges.

Installed capacity for each state is adjusted for planned additions and retirements reported by the U.S. Energy Information Administration (2016) from 2014 to 2025. Total generation from various types of capacity is defined as:

$$G_{it} = \sum_{j=cl}^{wo} G_{ijt} \qquad (2)$$

where the index j includes 13 different type of electricity generation, including coal (cl), geothermal (gt), hydro (hy), natural gas (ng), nuclear (nu), other (ot), other biomass (ob), other gas (og), petroleum (pe), pumped storage (ps), solar (sl), wind (wn), and wood (wo). The base year of generation is 2013.

Under the base case scenario, new generation requirements are met with new natural gas combined cycle generation (nc), G_{inct}, which is determined as follows:

$$G_{inct} = Q_{it} - B_{it} - G_{it} \qquad (3)$$

where, B_{it} is a balance term that includes net electricity imports and other miscellaneous adjustments, which is held fixed at base year values of 2013 over the forecast horizon.

The average cost of generation is defined as:

$$AC_{it} = \frac{\left[\sum_{j=cl}^{wo} c_{ijt} G_{ijt} + c_{inct} G_{inct}\right]}{G_{it} + G_{inct}} \qquad (4)$$

Where c_{ijt} is the levelized cost of existing generation in state i for capacity type j in year t and c_{inct} is the levelized cost of new natural gas combined cycle generation, defined as operating costs plus capital and maintenance costs:

$$c_{inct} = HR_{nc} \times P_{ingt} + \frac{p_{nc} K_{nc}\left[\frac{r(1+r)^t}{(1+r)^t - 1} + OM_{nc}\right]}{\left[K_{nc} U_{nc} \times 365 \times 24\right]} \qquad (5)$$

where HR_{nc} is the heat rate for new NGCC capacity in million BTU per Mwhr assumed to be 6.43, P_{ngt} is the price of natural gas paid by electric utilities in 2013 dollars per million BTU, p_{nc} is the so-called overnight capital costs of NGCC capacity equal to $1,023 per kilowatt (KW) capacity, K_{nc} is installed capacity of 400 KW, r is the discount rate assumed to be 7.1% per annum, t is the capital cost recovery period of 20 years, OM_{nc} is operating and maintenance expenditures per KW of capacity, and U_{nc} is the capacity utilization rate for NGCC units, which is assumed to be 85%. The last two terms in the denominator of the second term in equation (5) computes the number of hours in a calendar year so that levelized costs are in terms of dollars per megawatt hours of electricity generation. The values of these cost parameters are based upon data provided by EIA (2013). The first term in the brackets in the numerator of (5) is the capital cost recovery factor.

The average retail price for electricity is defined as a fixed markup over average costs of generation:

$$P_{it} = AC_{it} + M_{i2013} \qquad (6)$$

where M_{i2013} is the margin for transmission and distribution costs to customers in 2013. The base case model consists of equations (1)–(6).

For existing fossil fuel generation plants, actual observed heat rates and observed prices paid by electricity companies are used to calculate operating costs by state. Operating costs are simply the product of heat rates and the cost of fuels. Heat rates and operating costs in 2013 are reported in Tables 16 and 17, respectively.

Capital and maintenance costs for existing coal, natural gas, and nuclear plants are reported in Table 18 based upon Stacy and Taylor (2015), who collected actual observed costs for existing power plants based upon data reported by the Federal Energy Regulatory Commission (2016). Levelized costs to 2040 are projected on the basis of forecasts from the Energy Information Administration (2015).

The high oil and gas scenario, which results in relatively low natural gas prices, is used as the base case in this study because the EIA's reference case scenario consistently overestimates natural gas prices in recent years, as Figure 4 illustrates. Nevertheless, the models are computed using the EIA reference case with higher fossil fuel prices, and the results are compared in Appendix B.

Figure 5 presents the 12-state average projected levelized generation costs for existing coal and natural gas plants and new NGCC plants. Notice that all three series are relatively close, with NGCC costs the lowest due to greater thermal efficiency than existing fossil fuel plants. Levelized costs for new NGCC capacity are lowest given high efficiency. Coal-fired generation costs are highest given relatively low gas prices in the base case scenario.

Table 16: Heat Rates for Fossil Fuel Generation (Heat Rate in Million BTU/MWh)

	Coal	Natural Gas	Oil
Colorado	10.58	8.77	10.39
Delaware	11.81	7.37	8.89
North Carolina	10.03	7.25	10.39
New Mexico	10.57	8.57	11.04
Nevada	10.89	7.57	10.45
Oregon	9.80	7.28	9.58
Pennsylvania	10.23	7.56	8.50
Rhode Island	NA	7.79	6.93
South Carolina	10.00	8.09	10.18
Utah	9.92	7.75	10.11
Virginia	10.63	7.83	9.89
Wisconsin	10.41	7.69	4.29

Table 17: Fuel Operating Costs for Fossil Fuel Generation, 2013 ($/MWh)

	Coal	Natural Gas	Oil
Colorado	20.21	41.04	245.29
Delaware	37.81	29.76	192.04
North Carolina	38.12	36.16	234.41
New Mexico	24.41	36.27	269.67
Nevada	29.84	32.34	254.10
Oregon	19.21	27.72	211.35
Pennsylvania	25.27	30.26	200.84
Rhode Island	NA	44.03	152.35
South Carolina	37.48	37.05	235.13
Utah	20.24	30.76	226.91
Virginia	35.28	32.50	184.18
Wisconsin	24.14	33.76	35.64

The cost for hydroelectric generation is $14.70 per MWh, based upon observed data reported by Stacy and Taylor (2015). Generation from petroleum-fired capacity is computed on the basis of observed heat rates and oil prices and maintenance and capital recovery costs of $10.50 per MWh reported by Stacy and Taylor (2015).

The levelized costs for wind generation, c_{iwnt}, are defined as follows:

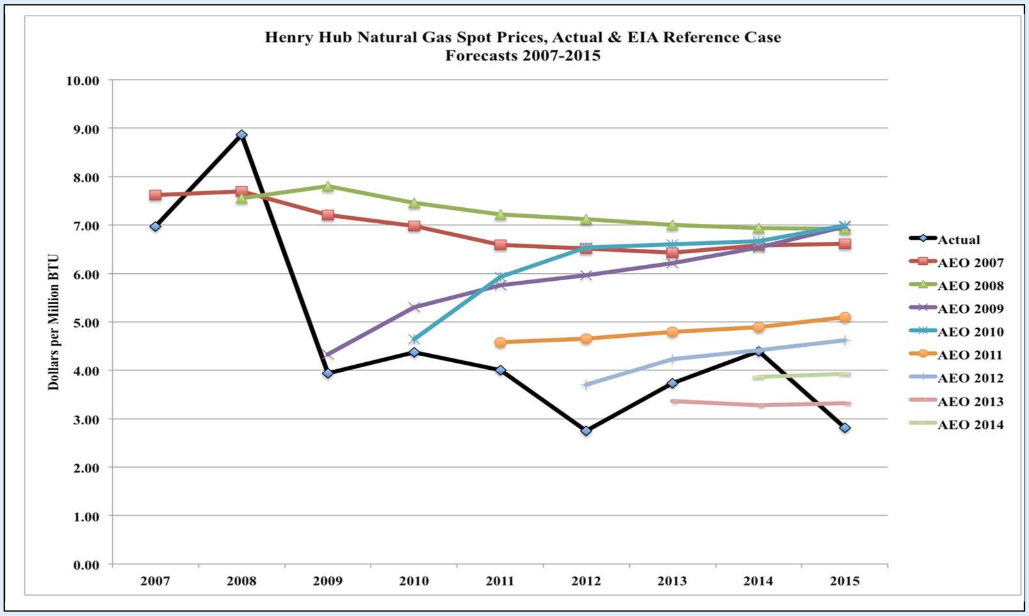
$$c_{iwnt} = \frac{p_{wnt}K_{wn}\left[\frac{r(1+r)^t}{(1+r)^t-1}+OM_{wn}\right]}{\left[K_{wn}U_{iwn}\times 365\times 24\right]} - \tau_{wn} \qquad (7)$$

Table 18: Capital and Maintenance Costs Fossil Fuel and Nuclear Plants, 2013 ($/MWh)

	Coal		Natural Gas		Nuclear	
	CapEx	**O&M**	**CapEx**	**O&M**	**CapEx**	**O&M**
Colorado	4.60	6.62	9.61	7.09		
Delaware	6.08	6.55	5.47	5.03		
North Carolina	7.91	5.33	5.47	5.03	5.54	14.19
New Mexico	3.10	5.91	5.47	5.03		
Nevada	15.92	13.96	5.83	4.60		
Oregon	6.27	6.47	4.81	4.35		
Pennsylvania	4.59	4.45	5.47	5.03	3.84	18.15
Rhode Island	6.08	6.55	5.47	5.03		
South Carolina	9.40	4.83	3.50	2.79	2.24	15.42
Utah	6.08	6.55	5.47	5.03		
Virginia	5.88	6.54	5.47	5.03	4.76	11.51
Wisconsin	50.86	47.75	5.47	5.03	7.81	23.81

Figure 4: EIA Forecast Accuracy of Henry Hub Prices

EIA's reference case scenario consistently over-estimates natural gas prices.



where p_{wnt} is equal to $2,213 per KW for capital construction costs in 2013, OM_{wn} is $39.55 per KW for operation and maintenance costs, K_{wn} is 100 megawatts, and the capacity factors, U_{iwn}, are reported below in Table 19 based upon data from EIA (2016). Note that levelized costs for wind are reduced by the production tax credit for wind power, τ_{wn}, which is equal to $23 per MWh.

Notice the wide dispersion in capacity factors for wind across states. Windier western states have generally higher-capacity factors compared to the eastern regions of the United States. The highest wind capacity factor is in Colorado, followed by Pennsylvania, New Mexico, Wisconsin, and Oregon. Also, reported in Table 19 are the shares of new capacity supplied by wind for each state. These

Figure 5: Projected Levelized Costs for Fossil Fuel Generation, 2016–2040

all three series are relatively close with NGCC costs the lowest due to greater thermal efficiency than existing fossil fuel plants.

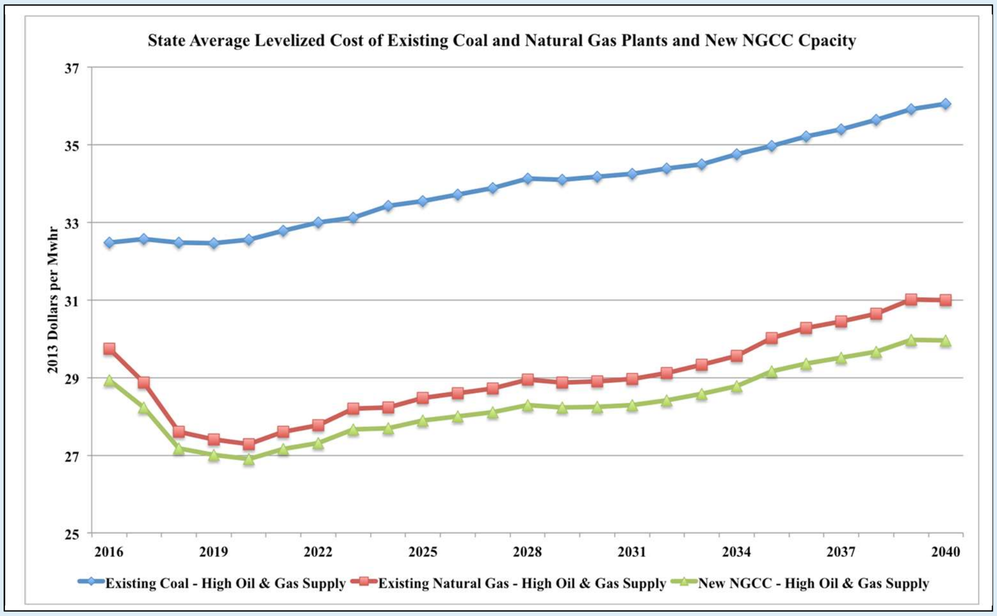


Table 19: Capacity Utilization and Shares of New RPS Capacity

	Capacity Utilization		Shares of RPS Capacity	
	Wind	**Solar**	**Wind**	**Solar**
Colorado	0.353	0.233	0.448	0.552
Delaware	0.255	0.180	0.909	0.091
North Carolina	0.151	0.117	0.885	0.115
New Mexico	0.322	0.233	0.110	0.890
Nevada	0.191	0.230	0.873	0.127
Oregon	0.269	0.219	0.036	0.963
Pennsylvania	0.285	0.153	0.018	0.982
Rhode Island	0.151	0.132	0.437	0.563
South Carolina	0.351	0.132	0.500	0.500
Utah	0.217	0.184	0.735	0.265
Virginia	0.151	0.117	0.680	0.320
Wisconsin	0.280	0.132	0.020	0.980

shares are determined based upon recent and planned mix of renewable capacity. Wind power is likely to play a major role in meeting RPS goals in Colorado, New Mexico, Oregon, Pennsylvania, Rhode Island, and Wisconsin.

The levelized costs for wind power appear in Table 20. Wind power technology is reaching maturity as noted by EIA (2013), so future overnight capital costs are assumed to decline 0.3% annually from 2016 to 2040. This reduces wind power costs by slightly more than 7.7% over the forecast horizon.

The levelized costs for solar photovoltaic generation, $c_{islt,}$ is defined as follows:

$$c_{islt} = \frac{p_{slt}\tau_{sl}K_{sl}\left[\frac{r(1+r)^t}{(1+r)^t-1}+OM_{sl}\right]}{\left[K_{sl}U_{isl}\times 365\times 24\right]} \quad (8)$$

where p_{isl} is equal to $2,479 per KW for capital construction costs, OM_{sl} is $39.90 per KW for operation and maintenance costs, K_{sl} is 150 megawatts, τ_{sl} is the investment tax credit of 30%, and the capacity factors, U_{isl}, are reported in Table 21 based upon data from EIA (2016). Given the lack of wind resources, most new renewable capacity is supplied by solar in some eastern states, such as Delaware, the Carolinas, and Virginia.

Projected levelized costs for solar power assume a 1.5% annual decline, which reduces solar costs by 30% from 2016 to 2040. Also note that the projected levelized costs for solar assume the investment tax credit remains in place. Despite this favorable treatment, levelized costs for several states, such as North Carolina, Rhode Island, and South Carolina are substantially higher than other states due to relatively low solar capacity factors.

Grid Disruption Costs

Additional renewable electricity generation displaces coal and natural gas generation and reduces the operational efficiency of existing fossil fuel facilities. To estimate these impacts, this study uses an open-access tool available from EPA (2014). This modeling tool is based upon statistical analysis by Fisher, et al. (2015), of the behavioral characteristics of individual electric generation units

Table 20: Projected Levelized Costs for Wind Power After Tax Credit by State, 2016–2040 ($/MWh, 2013 Dollars)

	2016	2020	2025	2030	2035	2040
Colorado	44.47	43.61	42.55	41.51	40.48	39.47
Delaware	70.52	69.33	67.86	66.42	65.00	63.60
North Carolina	134.84	132.83	130.35	127.91	125.51	123.15
New Mexico	50.92	49.98	48.82	47.68	46.55	45.45
Nevada	101.81	100.22	98.26	96.34	94.44	92.57
Oregon	65.42	64.29	62.90	61.54	60.19	58.87
Pennsylvania	60.60	59.54	58.23	56.93	55.66	54.41
Rhode Island	134.84	132.83	130.35	127.91	125.51	123.15
South Carolina	180.55	177.96	174.76	171.62	168.52	165.48
Utah	86.58	85.19	83.47	81.78	80.11	78.47
Virginia	134.84	132.83	130.35	127.91	125.51	123.15
Wisconsin	61.92	60.83	59.50	58.19	56.90	55.63

(EGUs) from publicly available hourly historical generation and emissions data. This tool tracks the generation and heat rates for each fossil EGU within 10 separate electricity generation systems within the United States.

For this study, this tool is used to simulate coal and natural gas generation displaced by renewable electricity generation. The percentage changes in heat rates for coal and gas generation are also estimated for various RPS goals. The AVERT tool is simulated for each region and state combination under four different RPS shares from one to twenty percent. Quadratic functions are then fitted to these model outcomes to estimate how fossil fuel displacement shares and the percentage changes in coal and natural gas heat rates adjust as the share of renewable energy approach the RPS goals presented in Table 22.

The average fossil fuel generation displacement shares and percentages changes in heat rates from the RPS goals are summarized in Table 23. For example, on average, a megawatt of renewable electricity generation displaces 0.7337 megawatts of coal-fired electricity generation and 0.2663 megawatts of natural gas generation in Pennsylvania. Likewise, the RPS goals for coal heat rates in Pennsylvania are 1.11% higher than the base case without RPS while the corresponding heat rates for natural gas are 1.64% higher.

Table 22: RPS Goals by State

	RPS Goal (%)	Year
Colorado	21.5	2020
Delaware	22.7	2026
North Carolina	11.9	2020
New Mexico	15.7	2021
Nevada	25.0	2025
Oregon	50.0	2040
Pennsylvania	7.8	2021
Rhode Island	14.5	2019
South Carolina	2.1	2021
Utah	20.0	2025
Virginia	6.0	2025
Wisconsin	10.0	2016

Table 21: Projected Levelized Costs for Solar Power After Investment Tax Credit by State, 2016–2040 ($/MWh, 2013 Dollars)

	2016	2020	2025	2030	2035	2040
Colorado	77.32	72.79	67.49	62.58	58.02	53.80
Delaware	99.83	93.97	87.13	80.79	74.91	69.46
North Carolina	153.92	144.89	134.35	124.57	115.50	107.10
New Mexico	77.46	72.91	67.61	62.69	58.12	53.89
Nevada	78.30	73.71	68.34	63.37	58.76	54.48
Oregon	82.38	77.55	71.91	66.67	61.82	57.32
Pennsylvania	118.01	111.09	103.01	95.51	88.56	82.11
Rhode Island	136.22	128.23	118.90	110.25	102.22	94.78
South Carolina	136.22	128.23	118.90	110.25	102.22	94.78
Utah	97.66	91.93	85.24	79.04	73.29	67.95
Virginia	153.92	144.89	134.35	124.57	115.50	107.10
Wisconsin	136.22	128.23	118.90	110.25	102.22	94.78

The shares of coal and natural gas generation displaced by renewables vary by state based upon the mix of capacity within each region. Likewise, heat rates also vary depending upon the existing level of renewable generation. States with higher levels of existing or legacy RPS generation, such as Colorado and Wisconsin, face higher increases in heat rates with additional levels of RPS generation. These displacement rates and percentage changes in heat rates are used to compute average system-wide costs under RPS, which are now discussed.

Average Costs Under RPS

Under renewable energy portfolio standards, new renewable electricity generation is given by:

$$R_{it} = \rho_{it} Q_{it} - \left(G_{islt} + G_{iwnt}\right) \geq 0 \qquad (9)$$

The inequality on the right indicates that new renewable generation is either positive or zero. Under the RPS, the equation for new generation from natural gas combined cycle capacity is given by:

$$G_{inct} = Q_{it} - B_{it} - G_{it} - R_{it} \qquad (10)$$

Hence, the RPS standard reduces the need for additional new natural gas combined cycle capacity and generation. So, while additional renewable generation would raise costs, some of these additional expenditures would be offset by lower outlays for new natural gas combined cycle generation to meet future electricity demand growth.

An additional benefit would occur from reduced generation from coal and natural gas powered generation units, D_{iclt} and D_{ingt}, respectively, which are calculated as follows:

$$\begin{aligned} D_{iclt} &= \delta_{iclt} R_{it} \\ D_{ingt} &= \delta_{ingt} R_{it} \end{aligned} \qquad (11)$$

where δ_{iclt} and δ_{ingt} are the shares of renewable generation displacing existing coal and natural gas generation summarized in Table 23. Total generation from existing capacity, therefore, becomes:

$$G_{it}^{rps} = \sum_{j \neq cl,ng} G_{ijt} - D_{iclt} - D_{ingt} \qquad (12)$$

Table 23: Average Fossil Fuel Displacement and Changes in Heat Rates from RPS

	RPS Displacement Shares		% Change in Heat Rates	
	Coal	**Natural Gas**	**Coal**	**Natural Gas**
Colorado	0.5546	0.4454	6.78	14.05
Delaware	0.6960	0.3040	0.09	0.14
North Carolina	0.4932	0.5068	0.44	0.58
New Mexico	0.2412	0.7588	0.66	2.81
Nevada	0.4627	0.5373	1.22	2.62
Oregon	0.4908	0.5092	1.92	4.11
Pennsylvania	0.7337	0.2663	1.11	1.64
Rhode Island	0.1343	0.8657	0.55	0.42
South Carolina	0.4931	0.5069	0.12	0.18
Utah	0.4973	0.5027	1.18	2.51
Virginia	0.4531	0.5469	0.50	0.83
Wisconsin	0.8183	0.1817	2.15	10.26

Additional electricity generation from renewable sources, however, would impose cycling costs on existing generation capacity to accommodate the intermittency of renewable generation. These costs raise the heat rates for existing coal and natural gas capacity. In this case, the levelized costs for existing coal and natural gas generation are defined as:

$$c_{iclt}^{rps} = \left(1+\theta_{iclt}\right) H_{iclt} w_{iclt} + x_{iclt} + o_{iclt}$$
$$c_{ingt}^{rps} = \left(1+\theta_{ingt}\right) H_{ingt} w_{ingt} + x_{ingt} + o_{ingt} \qquad (13)$$

where θ_{iclt} and θ_{ingt} are the percentage increases in heat rates, defined as million British Thermal Units (BTUs) per megawatt hour (MWh) summarized in Table 23, and x_{iclt}, x_{ingt}, o_{iclt}, and o_{ingt} are capital expenses and operating and maintenance costs per MWh for existing coal and natural gas generation, respectively.

Average generation costs under the RPS scenario, therefore, is as follows:

$$AC_{it}^{rps} = \frac{\left[\sum_{j \neq cl,ng} c_{ijt} G_{ijt} + c_{inct} G_{ingt} + c_{iclt}^{rps}\left(G_{iclt} - D_{iclt}\right) + c_{ingt}^{rps}\left(G_{ingt} - D_{ingt}\right) + c_{irt} R_{it}\right]}{G_{it}^{rps} + G_{inct}^{rps} + R_{it}} \qquad (14)$$

where c_{irt} is a weighted average the levelized costs generation from of solar and wind capacity. These weights vary by state and are based upon observations on capacity and generation in 2013.

Finally, retail electricity prices under the RPS are given by:

$$P_{it} = AC_{it}^{rps} + M_{i2013} \qquad (15)$$

In summary the RPS model is given by the demand equation (1) and the electricity supply model given by (9)–(15).

Net Costs of RPS

The costs of the RPS goals are estimated by calculating the difference in retail electricity expenditures between the base case and the RPS scenarios for each state. To understand the sources of changes in costs arising from the RPS goals, a cost decomposition is calculated for each state.

The first component of this decomposition is the cost associated with existing renewable energy capacity, which is assumed to be the result of RPS goals implemented prior to 2016. These costs are called net RPS legacy costs and include the direct costs of operating legacy RPS capacity including cycling costs less fuel cost savings arising from the displacement of coal and natural gas generation by renewable electricity generation.

The second component of the cost of RPS policies is incurred in the future as higher RPS goals are met. These are costs are defined in the same way as RPS legacy costs, but with avoided NGCC costs included.

The third cost component is the cost of federal renewable energy subsidies. For wind power, the subsidy is the $23 per megawatt hour production tax credit. Similarly, solar electricity generation units receive a 30% investment tax credit.

The total cost of RPS goals equals RPS legacy costs plus new RPS costs and subsidies. Reductions in carbon dioxide emissions are also calculated based upon the two scenarios and the direct (both legacy and new RPS) costs and subsidies per ton of avoided emissions are calculated.

Economic Effects

The changes in electricity prices and investments in both renewable energy and NGCC capacity will affect regional value added and employment. Changes in value added and employment for a 10% increase in electricity prices are presented in Tables 24 and 25 based upon the econometric analysis conducted by Patrick et al. (2015). These estimates vary by state and industry so that the economic effects of electricity price changes vary by state based in part upon the mix of industries. States with electricity-intensive industries would be most affected by changes in electricity prices.

Investment multipliers are reported in Table 26 based upon the estimates from the Jobs and Economic Development Impact Models (JEDI)

Table 24: Changes in Value Added for 10% Increase in Electricity Prices ($M, 2013 Dollars)

	Total	Metals	Paper	Wood	Man	Textiles	Minerals	Const.	Trans.	Other	Utilities
Colorado	-2,623	-32	-11	-12	-130	-6	-24	-390	-157	-2159	298
Delaware	-579	-6	-19	-1	-71	-2	-2	-54	-17	-458	50
North Carolina	-4,760	-105	-140	-71	-1321	-88	-53	-539	-203	-2682	443
New Mexico	-656	-2	-6	-2	-10	-1	-4	-117	-47	-552	86
Nevada	-1,185	-9	-6	-3	-13	-2	-8	-187	-109	-977	129
Oregon	-1,571	-110	-80	-111	-30	-2	-19	-222	-101	-1,128	232
Pennsylvania	-6,553	-642	-306	-72	-629	-18	-64	-740	-371	-4,438	725
Rhode Island	-492	-38	-8	-2	-24	-5	-2	-74	-16	-365	42
South Carolina	-1,638	-93	-190	-36	-186	-57	-24	-252	-82	-1,043	327
Utah	-1,681	-368	-45	-4	-115	-2	-21	-223	-93	-901	92
Virginia	-3,628	-39	-76	-57	-195	-36	-26	-534	-219	-2,834	386
Wisconsin	-2,643	-140	-326	-66	-193	-9	-42	-305	-157	-1,714	312

Table 25: Changes in Employment for 10% Increase in Electricity Prices (Jobs)

	Total	Metals	Paper	Wood	Man	Textiles	Minerals	Const.	Trans.	Other	Utilities
Colorado	-16,577	-86	-80	-162	-1,396	-107	-73	-2,759	-1,751	-10,705	542
Delaware	-2,923	-22	-44	-17	-261	-6	-6	-442	-288	-1,952	114
North Carolina	-31,868	-265	-859	-889	-3,903	-2,396	-143	-4,090	-3,012	-17,060	750
New Mexico	-5,140	-14	-29	-49	-310	-11	-18	-980	-527	-3,440	238
Nevada	-8,544	-49	-42	-53	-400	-35	-26	-1,236	-1,363	-5,596	257
Oregon	-13,463	-288	-261	-1,126	-1,629	-80	-45	-1,644	-1,374	-7,367	352
Pennsylvania	-46,032	-1,385	-1,288	-1,044	-5,229	-530	-215	-5,379	-6,053	-26,308	1,398
Rhode Island	-3,342	-52	-63	-31	-407	-38	-6	-382	-268	-2,188	94
South Carolina	-14,605	-204	-687	-413	-1,894	-1,289	-72	-1,848	-1,376	-7,618	796
Utah	-9,669	-154	-149	-102	-1,169	-84	-51	-1,649	-1,274	-5,312	276
Virginia	-26,843	-147	-419	-721	-2,210	-520	-86	-4,211	-2,892	-16,302	666
Wisconsin	-23,543	-620	-1,668	-920	-4,567	-211	-89	-2,229	-2,516	-11,305	583

developed by National Energy Renewable Energy Laboratory (2016). Considine and Manderson (2014, 2015) also use these models to estimate the employment impacts from RPS policies in Arizona and California.

The JEDI models are based upon estimates for investment expenditures and operation costs for various types of electricity generation technology. Given these expenditures, which vary by state, economic input-output models are used to estimate effects on value added and employment.

The JEDI value-added multipliers appear in Table 26, which are defined in terms of dollars of value added per dollar of investment. Similarly, the employment multipliers are expressed in number of full-time equivalent jobs per dollar of investment. Notice, that the value-added and employment multipliers are somewhat higher than the corresponding multipliers for investments in wind power and NGCC capacity. This finding suggest a solar technology has more extensive local supply chain linkages than wind and NGCC technologies that are supported either imports from outside each states' boundaries. Also, there is some variation in these multipliers across states, reflecting the presence of absence of industries and services supporting the supply chains for each technology.

RELEVANT LEGISLATION

The following energy-related bills are currently graded on the RI Center for Freedom & Prosperity's Freedom Index and may contribute to the negative policy approach described in this report.[5] Note that this list is not exhaustive or final, representing only the current status of the Freedom Index.

- **H7413 & S2185 (-3):** to extend the phase-in of the state's renewable energy standard so, instead of ending at 16% of energy by 2019, it will continue until it reaches 40% of energy by 2035
- **H7325 (-3):** to create a new tax (called a "fee") on all fuel and electricity based deriving from carbon to fund green-energy programs for low-income residents and make payments to residents and employers regardless of their energy use

Table 26: Value-Added and Employment Investment Multipliers for Solar, Wind, and NGCC

	Solar		Wind		Natural Gas	
	Value-Add/$	**Jobs/$**	**Value-Add/$**	**Jobs/$**	**Value-Add/$**	**Jobs/$**
Colorado	0.2258	2.9565	0.2078	2.4459	0.2923	2.5876
Delaware	0.1921	2.7415	0.1761	2.1248	0.2569	2.0132
North Carolina	0.2071	3.3325	0.1892	2.4138	0.2777	2.4237
New Mexico	0.1817	3.4155	0.1607	2.1836	0.2416	2.1972
Nevada	0.2131	2.9768	0.1969	2.1299	0.2713	2.1653
Oregon	0.2055	3.3672	0.1857	2.3990	0.2720	2.4211
Pennsylvania	0.2194	3.2295	0.2091	2.4543	0.2977	2.5412
Rhode Island	0.2097	3.0812	0.1884	2.1906	0.2774	2.1944
South Carolina	0.1853	3.4696	0.1630	2.3973	0.2553	2.4998
Utah	0.2101	3.3548	0.2059	2.5244	0.2848	2.6915
Virginia	0.2081	2.7776	0.1919	2.2536	0.2751	2.2895
Wisconsin	0.2012	3.2736	0.1938	2.5226	0.2839	2.6010

- **H7815 & S2483 (-3):** to create a new requirement for suppliers of electricity to buy a minimum amount of energy from "thermal" sources or to pay a fee instead
- **H7070 & S2747 (-2):** to create a new Green Energy Revolving Fund under the state's infrastructure bank using $60 million in new public debt to give loans between $2,500 and $40,000 for favored projects
- **H7262 (-2):** to create a revolving fund for low-interest loans and "grants" to small businesses seeking to install solar panels, to provide tax credits to companies developing or manufacturing solar technology, and to make all state-owned property available for solar farms
- **S2177 (-2):** to require municipalities to exempt larger renewable energy systems from taxation
- **H7473 & S2181 (-2):** to extend the Renewable Energy Growth Program for an additional 10 years, continuing fees charged to energy users with higher energy goals
- **S2450 (-2):** to extend the surcharge charged to all electricity customers for renewable energy programs for an additional 10 years
- **H7158 & S2165 (-2):** to remove the requirement that a municipal government receive direct voter approval before creating new aggregated energy agreements within the city/town or with other cities or towns
- **H7585 & 2592 (-1):** to expand the state's net-metering program to allow energy credits to be transferred to other location and to include potential credits (or charges) for estimated effects such as "improved local liability" of the grid overall
- **S2190 (-1):** to bring back the income tax credit for residential renewable energy systems
- **S2351 (-1):** to create an "incentive" fund to hand out $500 subsidies to Rhode Islanders who install small-scale solar energy units, with a maximum of $100,000
- **H7954 (-1):** to require cities and towns to exempt from taxation small-scale renewable energy systems (10 KW residential; 100 KW commercial) for 20 years or until transfer of the property

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APPENDIX B: ECONOMETRIC RESULTS FOR ALTERNATIVE DEMAND MODELS

Table 27: Elasticities of Electricity Demand for First Difference Model

	Own Price Elasticity	Gross State Product Elasticity
Colorado	-0.161	0.682
Delaware	-0.219	0.378
North Carolina	-0.222	0.610
New Mexico	-0.350	0.421
Nevada	-0.217	0.673
Oregon	-0.323	0.584
Pennsylvania	-0.204	0.519
Rhode Island	-0.118	0.363
South Carolina	-0.259	0.783
Utah	-0.145	0.752
Virginia	-0.188	0.652
Wisconsin	-0.302	0.720
Average	-0.226	0.595

Table 28: Panel Data Estimates for Electricity Demand

	Constant	Log real Price	Log GSP
Pooled OLS*	0.0118	-0.2011	0.4329
Estimate	5.3474	-10.2083	10.6906
t-Statistic	[.000]	[.000]	[.000]
P-Value			
Fixed Effects		-0.1943	0.4008
Estimate		-9.9058	9.7130
t-Statistic		[.000]	[.000]
P-Value			
Random Effects	0.0124	-0.1983	0.4197
Estimate	4.9162	-10.1332	10.3339
t-Statistic	[.000]	[.000]	[.000]
P-Value	5.3474	-10.2083	10.6906

Note: Hausman test: Ho: RE vs. FE: Chisq(2) - 9.0028, Prob. Value = 0.0111
* Best Schwarz-Bayes Information Criterion

Table 29: Electricity Demand First Difference Model Parameter Estimates by State

	Estimate	Log of Real Price	Log of Real GSP
Colorado	Estimate	-0.161	0.682
	t-Statistic	-2.677	11.640
	P-Value	[.011]	[.000]
Delaware	Estimate	-0.219	0.378
	t-Statistic	-3.334	3.040
	P-Value	[.002]	[.004]
North Carolina	Estimate	-0.222	0.610
	t-Statistic	-2.706	6.007
	P-Value	[.010]	[.000]
New Mexico	Estimate	-0.350	0.421
	t-Statistic	-2.806	3.603
	P-Value	[.008]	[.001]
Nevada	Estimate	-0.217	0.673
	t-Statistic	-3.203	8.735
	P-Value	[.003]	[.000]
Oregon	Estimate	-0.323	0.584
	t-Statistic	-4.133	5.903
	P-Value	[.000]	[.000]
Pennsylvania	Estimate	-0.204	0.519
	t-Statistic	-3.373	4.512
	P-Value	[.002]	[.000]
Rhode Island	Estimate	-0.118	0.363
	t-Statistic	-2.934	3.661
	P-Value	[.005]	[.001]
South Carolina	Estimate	-0.259	0.783
	t-Statistic	-3.532	8.175
	P-Value	[.001]	[.000]
Utah	Estimate	-0.145	0.752
	t-Statistic	-2.100	11.473
	P-Value	[.042]	[.000]
Virginia	Estimate	-0.188	0.652
	t-Statistic	-3.362	7.937
	P-Value	[.002]	[.000]
Wisconsin	Estimate	-0.302	0.720
	t-Statistic	-3.795	7.415
	P-Value	[.000]	[.000]

Table 30: Comparison of RPS Impacts

		% Change in Prices		% in Value Added		% Change in Jobs	
		HOG	REF	HOG	REF	HOG	REF
Colorado	2016	6.12	5.78	-1,442	-1,354	-8,060	-7,507
	2020	8.23	7.10	-1,996	-1,703	-11,619	-9,774
	2025	7.69	6.23	-1,992	-1,612	-12,445	-10,048
	2030	7.32	5.89	-1,895	-1,520	-11,823	-9,458
	2035	6.69	5.14	-1,730	-1,323	-10,779	-8,214
	2040	5.93	4.10	-1,530	-1,052	-9,516	-6,501
Delaware	2016	11.02	10.20	-603	-556	-2,705	-2,479
	2020	14.50	11.89	-812	-663	-3,845	-3,108
	2025	14.99	11.46	-839	-635	-3,970	-2,953
	2030	12.50	9.27	-715	-528	-3,536	-2,588
	2035	10.14	6.78	-578	-384	-2,846	-1,871
	2040	8.20	4.23	-466	-238	-2,272	-1,143
North Carolina	2016	10.04	9.50	-3,899	-3,641	-17,821	-16,103
	2020	16.06	13.77	-7,145	-6,060	-43,277	-36,048
	2025	14.12	11.46	-6,664	-5,399	-44,093	-35,644
	2030	12.55	10.08	-5,918	-4,740	-39,107	-31,227
	2035	11.03	8.28	-5,196	-3,887	-34,289	-25,541
	2040	9.79	6.22	-4,606	-2,908	-30,345	-19,009
New Mexico	2016	6.18	5.71	-239	-208	-743	-500
	2020	6.77	5.29	-444	-347	-3,483	-2,719
	2025	5.95	4.13	-390	-271	-3,060	-2,122
	2030	5.30	3.60	-348	-237	-2,724	-1,853
	2035	4.54	2.82	-298	-185	-2,333	-1,450
	2040	3.92	1.88	-251	-117	-1,921	-874
Nevada	2016	14.77	13.86	-1,711	-1,601	-11,827	-11,064
	2020	15.60	13.08	-1,792	-1,499	-12,540	-10,484
	2025	15.14	11.48	-1,715	-1,285	-11,868	-8,803
	2030	13.28	9.82	-1,534	-1,124	-10,813	-7,869
	2035	11.21	7.69	-1,287	-873	-9,037	-6,071
	2040	9.12	5.26	-1,038	-585	-7,237	-4,014
Oregon	2016	9.41	9.08	-1,451	-1,399	-12,309	-11,866
	2020	10.00	9.08	-1,571	-1,427	-13,459	-12,226
	2025	11.09	9.32	-1,636	-1,366	-13,547	-11,236
	2030	10.55	8.77	-1,646	-1,365	-14,048	-11,646
	2035	9.83	7.86	-1,532	-1,222	-13,077	-10,423
	2040	9.11	6.82	-1,418	-1,060	-12,095	-9,034

Table 30: Comparison of RPS Impacts (Continued)

		% Change in Prices		% in Value Added		% Change in Jobs	
		HOG	REF	HOG	REF	HOG	REF
Pennsylvania	2016	2.02	2.01	-1,142	-1,140	-7,138	-7,121
	2020	2.39	2.24	-1,385	-1,287	-8,827	-8,158
	2025	2.34	2.10	-1,508	-1,351	-10,458	-9,366
	2030	2.20	1.99	-1,412	-1,274	-9,784	-8,812
	2035	2.04	1.79	-1,308	-1,146	-9,046	-7,913
	2040	1.86	1.52	-1,187	-966	-8,194	-6,660
Rhode Island	2016	12.60	12.37	-579	-568	-3,649	-3,574
	2020	16.47	14.10	-805	-689	-5,423	-4,651
	2025	14.75	11.38	-718	-554	-4,831	-3,720
	2030	13.59	11.08	-661	-537	-4,442	-3,600
	2035	12.43	9.59	-604	-465	-4,059	-3,116
	2040	11.04	7.34	-536	-355	-3,598	-2,377
South Carolina	2016	2.40	2.39	-312	-312	-2,063	-2,057
	2020	2.94	2.67	-330	-288	-1,668	-1,293
	2025	3.75	3.23	-435	-346	-2,325	-1,534
	2030	3.14	2.62	-485	-400	-4,073	-3,318
	2035	2.54	1.92	-389	-286	-3,232	-2,321
	2040	2.05	1.14	-309	-160	-2,522	-1,217
Utah	2016	4.81	4.79	-818	-815	-4,745	-4,728
	2020	8.28	7.68	-1,147	-1,046	-4,049	-3,471
	2025	11.19	9.78	-1,618	-1,382	-6,683	-5,331
	2030	9.97	8.57	-1,644	-1,408	-9,126	-7,772
	2035	8.64	7.14	-1,421	-1,168	-7,854	-6,402
	2040	7.28	5.47	-1,192	-888	-6,551	-4,807
Virginia	2016	4.95	4.94	-1,601	-1,599	-10,800	-10,784
	2020	6.96	6.24	-2,241	-1,982	-15,040	-13,146
	2025	8.52	7.28	-2,769	-2,322	-18,731	-15,444
	2030	7.32	6.23	-2,608	-2,212	-19,042	-16,121
	2035	6.22	4.96	-2,213	-1,758	-16,133	-12,773
	2040	5.38	3.61	-1,906	-1,271	-13,873	-9,197
Wisconsin	2016	4.13	4.13	-1,014	-1,014	-8,694	-8,699
	2020	4.03	3.91	-1,048	-1,017	-9,257	-8,992
	2025	3.73	3.52	-966	-912	-8,533	-8,052
	2030	3.41	3.18	-881	-821	-7,764	-7,232
	2035	3.07	2.80	-790	-722	-6,958	-6,348
	2040	2.74	2.41	-703	-617	-6,176	-5,414

Notes: HOG = EIA High Oil and Gas Scenario
REF = EIA Reference Case Scenario

[1] RI Center for Freedom and Prosperity. “The Economic Impact of Rhode Island’s Renewable Energy Standard: How Energy Mandates Will Harm the Economy.” February 2014. Available at: rifreedom.org/2014/02/economic-impact-of-rhode-islands-renewable-energy-standard/

[2] RI Center for Freedom and Prosperity. “The Jobs & Opportunity Index (JOI).” Available at: rifreedom.org/JOI/

[3] Donnis, Ian. “Is Deepwater Wind's Block Island Project Worth The Cost To Ratepayers?” Rhode Island Public Radio. 2/23/16. Available at: ripr.org/post/deepwater-winds-block-island-project-worth-cost-ratepayers

[4] The selection of these states is determined by the states expressing an interest in this study to the Interstate Policy Alliance, which sponsored this study.

[5] RI Center for Freedom and Prosperity. “The Rhode Island Freedom Index.” Available at: rifreedom.org/freedomindex/